THIS FILING IS		
Item 1: ☒ An Initial (Original) Submission	OR ☐	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)

Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)

Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Entergy Arkansas, Inc.	End of 2013/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/eforms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ___________ , we have also reviewed schedules ___________________of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year/Period of Report
Entergy Arkansas, Inc.	End of 2013/Q4

03 Previous Name and Date of Change *(if name changed during year)*

/ /

04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)*
425 West Capitol Avenue, Little Rock, Arkansas 72201

05 Name of Contact Person	06 Title of Contact Person
Gina G. Bellott	Sr. Lead Accountant

07 Address of Contact Person *(Street, City, State, Zip Code)*
639 Loyola Avenue, New Orleans, Louisiana 70113

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(504) 576-6753	(1) ☒ An Original (2) ☐ A Resubmission	/ /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Alyson M. Mount	Alyson M. Mount	04/17/2014
02 Title Sr. VP & Chief Accounting Officer		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	NA
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	NA
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	NA
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	NA
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	NA
66	Generating Plant Statistics Pages	410-411	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	NA
	Stockholders' Reports Check appropriate box: [ ] Two copies will be submitted [X] No annual report to stockholders is prepared		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Alyson M. Mount
Senior Vice President and Chief Accounting Officer
639 Loyola Avenue
New Orleans, Louisiana 70113

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Arkansas
October 2, 1926

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

None

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Arkansas - Electric Utility Service
Missouri - Electric Utility Service
Tennessee - Electric Utility Service

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

As of December 31, 2013, Entergy Corporation owned 46,980,196 shares of the Respondent's common stock which represented 100% of the voting rights.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	System Fuels, Inc.			(1)
2	Entergy Arkansas Restoration Funding, LLC		100%	
3	Transmission Company Arkansas, LLC		100%	
4				
5				
6				
7				
8				
9				
10	(1) Entergy Arkansas, Entergy Louisiana			
11	Properties, LLC, Entergy Mississippi, and			
12	Entergy New Orleans own 35%, 33%, 19%, and			
13	13%, respectively of all the common stock			
14	of System Fuels, Inc., a subsidiary			
15	incorporated in Louisiana that until the first			
16	quarter of 2011 implemented and/or			
17	maintained certain programs to procure,			
18	deliver, and store fuel supplies for those			
19	companies.			
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President and Chief Executive Officer		
2	of Entergy Arkansas, Inc.	Hugh T. McDonald	342,791
3			
4	Chief Executive Officer and Chairman of the Board		
5	of Entergy Corporation (1)	J. Wayne Leonard	
6			
7	Executive VP and Chief Financial Officer		
8	of Entergy Corporation (2)	Leo P. Denault	
9			
10	Chief Executive Officer and Chairman of the Board		
11	of Entergy Corporation (3)	Leo P. Denault	
12			
13	Executive VP and Chief Financial Officer		
14	of Entergy Corporation (3)	Andrew S. Marsh	
15			
16	Sr. VP and Chief Accounting Officer of Entergy Corp.	Alyson M. Mount	
17			
18	Executive VP & Chief Operating Officer		
19	of Entergy Corporation	Mark T. Savoff	
20			
21	Exec. VP and General Counsel of Entergy Corp.	Marcus V. Brown	
22			
23	Group President Utility Operations of Entergy Corp.	Theodore H. Bunting, Jr.	
24			
25	Exec VP and Chief Nuclear Officer of Entergy Corp. (4)	John T. Herron	
26			
27	Exec VP and Chief Nuclear Officer of Entergy Corp. (5)	Jeffrey S. Forbes	
28			
29	Executive VP - Human Resources and Administration		
30	of Entergy Corporation (6)	E. Renae Conley	
31			
32	Sr. VP - Human Resources and Chief Diversity		
33	Officer of Entergy Corporation (7)	Donald W. Vinci	
34			
35	Executive VP & Chief Administrative Officer		
36	of Entergy Corporation	Roderick K. West	
37			
38	(1) retired January 2013		
39	(2) ceased January 2013		
40	(3) elected February 2013	* Officers whose salaries are not	
41	(4) resigned January 2013	presented were compensated by	
42	(5) elected January 2013	other System companies and not	
43	(6) retired September 2013	by Entergy Arkansas, Inc.	
44	(7) elected September 2013		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Hugh T. McDonald - President and Chief Executive Officer	
2	of Entergy Arkansas, Inc.	425 W. Capitol Avenue, 40th Floor, Little Rock, AR 72201
3		
4	Theodore H. Bunting, Jr. - Group President	
5	Utility Operations of Entergy Corporation	639 Loyola Avenue, New Orleans, LA 70113
6		
7	Leo P. Denault - Executive VP & Chief Financial Officer	
8	of Entergy Corporation (1)	639 Loyola Avenue, New Orleans, LA 70113
9		
10	Andrew S. Marsh - Executive VP & Chief Financial Officer	
11	of Entergy Corporation (2)	639 Loyola Avenue, New Orleans, LA 70113
12		
13	Mark T. Savoff - Executive VP & Chief Operating Officer	
14	of Entergy Corporation	639 Loyola Avenue, New Orleans, LA 70113
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16		
17	(1) ceased January 2013	
18	(2) elected February 2013	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates? [X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Electric Rate Schedule No. 94 --	
2	Entergy System Agreement (Service Schedules	
3	MSS-1 and MSS-4 containing formula rates)	
4	Baseline Tariff Filing	Docket No. ER13-432
5	Spindletop Regulatory Asset amendment	Docket No. ER11-2131
6	Little Gypsy Costs Amendment	Docket No. ER12-1384
7	Interuptible Load Amendment	Docket No. ER12-1881
8	River Bend 30 A&G Amendment	Docket No. ER12-1888
9		
10		
11	FERC Electric Tariff (OATT)	
12	Baseline Tariff Filing	Docket No. ER12-1895
13	Amendment to Schedule 7 and Attachment H	Docket No. ER12-1428
14		
15	Electric Rate Schedule No. 82--	
16	PCITSA with Arkansas Electric Cooperative Corp.	
17	Baseline Tariff Filing	Docket No. ER13-1194
18		
19	Electric Rate Schedule No. 99 -	Docket No. ER13-1195
20	with the Cities of West Memphis and Prescott,	
21	Arkansas	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[X] Yes
[ ] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20130530-5246	05/30/2013	ER13-1595	2013 System Agmt	RS No. 94
2				Sch.MSS-3 - RPCE	PP 30.11-30.13
3					
4					
5	20130531-5385	05/31/2013	ER13-1623	2013 OATT Rate Update	OATT
6					
7					
8	20130329-5161	03/29/2013	ER13-1194	2013 Update - AECC	RS No. 82
9					
10	20130329-5162	03/29/2013	ER13-1195	2013 Update - Cities	RS No. 99
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
1	111	Comparative Balance Sheet	(c)	57
2	117	Statement of Income for the Year	(d)	70
3	117	Statement of Income for the Year	(c)	70
4	118	Statement of Retained Earnings	(d)	29
5	118	Statement of Retained Earnings	(d)	29
6	118	Statement of Retained Earnings	(d)	36
7	118	Statement of Retained Earnings	(c)	36
8	204, 206	Electric Plant in Service	(b)	8-14, 50
9	204, 206	Electric Plant in Service	(b)	8-14, 18-24, 27-34, 37-43
10				and 50
11	206	Electric Plant in Service	(b)	48-57
12	204, 206	Electric Plant in Service	(b)	4, 86-95
13	206	Electric Plant in Service	(b)	97
14	219	Accumulated Provision for Depreciation	(b)	1
15	219	Accumulated Provision for Depreciation	(b)	1
16	219	Accumulated Provision for Depreciation	(b)	1
17	227	Materials and Supplies	(c)	1, 2
18	227	Materials and Supplies	(c)	12, 16
19	234	Accumulated Deferred Income Taxes (Account 190)	(c)	2
20	262	Taxes Accrued, Prepaid and Charged During Year	(d)	17, 18
21	262	Taxes Accrued, Prepaid and Charged During Year	(d)	17, 18
22	262	Taxes Accrued, Prepaid and Charged During Year	(d)	18
23	262	Taxes Accrued, Prepaid and Charged During Year	(d)	17
24	262	Taxes Accrued, Prepaid and Charged During Year	(d)	2, 9
25	262	Taxes Accrued, Prepaid and Charged During Year	(d)	3, 4 10
26	266	Accumulated Deferred Investment Tax Credits	(f)	8
27	275	Accumulated Deferred Income Taxes (Account 282)	(k)	2
28	277	Accumulated Deferred Income Taxes (Account 283)	(k)	3
29	320	Electric Operations and Maintenance Expense	(c)	4, 6-11, 15-19
30	320-321	Electric Operations and Maintenance Expense	(b)	5, 25, 63
31	320-321	Electric Operations and Maintenance Expense	(c)	4, 6-11, 15-19, 24, 26-32
32				35-39, 44-49, 53-57, 62
33				64-66, and 69-72
34	321	Electric Operations and Maintenance Expense	(c)	112
35	321	Electric Operations and Maintenance Expense	(c)	93,107
36	323	Electric Operations and Maintenance Expense	(c)	181-193
37	323	Electric Operations and Maintenance Expense	(c)	181-184 and 186-193
38	323	Electric Operations and Maintenance Expense	(c)	185
39	323	Electric Operations and Maintenance Expense	(c)	185
40	336	Depreciation Expense	(f)	2
41	336	Depreciation Expense	(f)	7
42	336	Depreciation Expense	(f)	2-7
43	336	Depreciation Expense	(f)	10
44	402-403	Steam-Electric Generating Plant Instructions	All	5

Name of Respondent Entergy Arkansas, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

INFORMATION ON FORMULA RATES (continued)
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
1		Footnotes explaining the differences are attached		
2				
3				
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Schedule Page: 1062.1 Line No.: 3 Column: b

Line No.	Page No(s).	Schedule	Column	Line No.
1	111	**Comparative Balance Sheet** Prepayments used in 4th Rev. RS No. 94, Service Schedule MSS-4, differs from Form 1 amounts because the formula rate reflects an allocation of the balance at the last day of the previous month, allocated using plant ratios	(c)	57
2	117	**Statement of Income for the Year** Interest expense used in 4th Rev. RS No. 94, Service Schedules MSS-1 and MSS-3, differs from Form 1 amounts because the formula rate reflects the embedded cost of debt at December 31 of the previous year times the Debt Capitalization ratio at December 31 of the previous year	(d)	70
3	117	**Statement of Income for the Year** Interest expense used in 4th Rev. RS No. 94, Service Schedule MSS-4, differs from Form 1 amounts because the formula rate reflects the embedded cost of debt at the last day of the previous month times the Debt Capitalization ratio at the last day of the previous month	(c)	70
4	118	**Statement of Retained Earnings** Return on Preferred Stock used in 4th Rev. RS No. 94, Service Schedules MSS-1 and MSS-2, differs from Form 1 amounts because the formula rate calculates Return on Preferred Stock using the embedded cost of Preferred Stock at December 31 of the previous year times the Preferred Stock Capitalization ratio at December 31 of the previous year	(d)	29
5	118	**Statement of Retained Earnings** Return on Preferred Stock used in 4th Rev. RS No. 94, Service Schedule MSS-4, differs from Form 1 amounts because the formula rate calculate Return on Preferred Stock using the embedded cost of Preferred Stock at the last day of the previous month times the Preferred Stock Capitalization ratio at the last day of the previous month	(d)	29
6	118	**Statement of Retained Earnings**	(d)	36

		Return on Common Equity used in RS No. 94, Service Schedules MSS-1 and MSS-2, differs from Form 1 amounts because the formula rate calculates Return on Common Equity using a stated Return on Equity of 11.0 percent times the Common Stock Capitalization ratio at December 31 of the previous year		
7	118	**Statement of Retained Earnings** Return on Common Equity used in 4th Rev. RS No. 94, Service Schedules MSS-4, differs from Form 1 amounts because the formula rate calculates Return on Common Equity using a stated Return on Equity of 11.0 percent times the Common Stock Capitalization ratio at the last day of the previous year	(c)	36
8	204, 206	**Electric Plant in Service** Plant investment used in 4th Rev. RS No. 94, Service Schedules MSS-1, differs from Form 1 amounts because the formula rate only reflects the cost of intermediate gas and oil units, plus the cost of step-up transformers and associated transmission equipment related to the intermediate gas and oil units, less the proportionate share of ADIT in Account 282	(b)	8-14, 50
9, 10	204, 206	**Electric Plant in Service** Plant investment used in 4th Rev. RS No. 94, Service Schedules MSS-4, differs from Form 1 amounts because the formula rate only reflects the cost of the Designated Generating Unit, plus the cost of step-up transformers and associated transmission equipment related to the Designated Generating Unit, at the last day of the previous month	(b)	8-14, 18-24, 27-34, 37-43 and 50
11	206	**Electric Plant in Service** Plant investment used in 4th Rev. RS No. 94, Service Schedule MSS-2, differs from Form 1 amounts because the formula rate only reflects Inter-Transmission Investment (i.e. (1) the cost of transmission lines operated at 115 kV and above that connect to another company’s transmission system, (2) all other lines operated at 230 kV and above, and (3) certain substation equipment)	(b)	48-57
12	204, 206	**Electric Plant in Service** Plant investment used in 4th Rev. RS No. 94, Service Schedule MSS-4,	(b)	4, 86-95

		differs from Form 1 amounts because the formula rate reflects an allocation of Misc. Intangible and General Plant investment at the last day of the previous month using a Labor Ratio		
13	206	**Electric Plant in Service** Plant investment used in 4th Rev. RS No. 94, Service Schedule MSS-4, differs from Form 1 amounts because the formula rate includes a direct assignment of the cost of any coal mining equipment associated with the Designated Generating Unit at the last day of the previous month	(b)	97
14	219	**Accumulated Provision for Depreciation (“APD”)** APD used in 4th Rev. RS No. 94, Service Schedule MSS-1, differs from Form 1 amounts because the formula rate only reflects the APD related to the intermediate gas and oil units, plus the APD related to the step-up transformers and associated transmission equipment related to the intermediate gas and oil units	(b)	1
15	219	**Accumulated Provision for Depreciation** APD used in 4th Rev. RS No. 94, Service Schedule MSS-2, differs from Form 1 amounts because the formula rate only reflects the APD related to the Inter-Transmission Investment	(b)	1
16	219	**Accumulated Provision for Depreciation** APD used in 4th Rev. RS No. 94, Service Schedule MSS-4, differs from Form 1 amounts because the formula rate only reflects the APD related to the Designated Generating Unit at the last day of the previous month	(b)	1
17	227	**Materials and Supplies** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-4, differ from Form 1 amounts because the formula rate only reflects the Fuel Inventory related to the Designated Generating Unit at the last day of the previous month	(c)	1-2
18	227	**Materials and Supplies** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-4, differ from Form 1 amounts because the formula rate only reflects the Materials and Supplies related to the	(c)	12, 16

FOOTNOTE DATA

		Designated Generating Unit at the last day of the previous month		
19	234	**Accumulated Deferred Income Taxes(Account 190)** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-4, differ from Form 1 amounts because the formula rate either directly assigns any ADIT related to the Designated Generating Unit or allocates ADIT based on a Plant Ratio	(c)	2
20	262	**Taxes Accrued, Prepaid and Charged During Year** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-1, differ from Form 1 amounts because the formula rate only reflects the corporate franchise and ad valorem taxes related to the intermediate gas and oil units	(d)	17, 18
21	262	**Taxes Accrued, Prepaid and Charged During Year** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-2, differ from Form 1 amounts because the formula rate only reflects the corporate franchise and ad valorem taxes related to the Inter-Transmission Investment	(d)	17, 18
22	262	**Taxes Accrued, Prepaid and Charged During Year** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-4, differ from Form 1 amounts because the formula rate allocates Corporate Franchise Taxes based on a Plant Ratio	(d)	18
23	262	**Taxes Accrued, Prepaid and Charged During Year** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-4, differ from Form 1 amounts because the formula rate only reflects the ad valorem taxes related to the Designated Generating Unit	(d)	17
24	262	**Taxes Accrued, Prepaid and Charged During Year** Costs used in 4th Rev. RS No. 94, Service Schedules MSS-1, MSS-2 and MSS-4, differ from Form 1 amounts because the formula rates calculate State and Federal income taxes using the incremental statutory rate	(d)	2, 9
25	262	**Taxes Accrued, Prepaid and Charged During Year** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-4, differ from Form 1 amounts because the formula	(d)	3, 4, 10

		rate allocates Payroll Taxes based on a Labor Ratio		
26	266	**Accumulated Deferred Investment Tax Credits** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-4, differ from Form 1 amounts because the formula rate either directly assigns any ITC Amortization related to the Designated Generating Unit or allocates ITC Amortization based on a Plant Ratio	(f)	8
27	275	**Accumulated Deferred Income Taxes (Account 282)** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-4, differ from Form 1 amounts because the formula rate either directly assigns any ADIT related to the Designated Generating Unit or allocates ADIT based on a Plant Ratio	(k)	2
28	277	**Accumulated Deferred Income Taxes (Account 283)** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-4, differ from Form 1 amounts because the formula rate either directly assigns any ADIT related to the Designated Generating Unit or allocates ADIT based on a Plant Ratio	(k)	3
29	320	**Electric Operations and Maintenance Expense** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-1, differ from Form 1 amounts because the formula rate only reflects the Production O&M Expenses related to intermediate gas and oil units	(c)	4, 6-11, 15-19
30	320-321	**Electric Operations and Maintenance Expense** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-3, Paragraphs 30.02 through 30.10, differ from Form 1 amounts because the formula rate: (1) assigns the cost of fuel and purchased power on an hourly basis; (2) develops the cost of fuel for each generating unit by multiplying the average BTU/kWh for the previous year times the current estimated cost of fuel per BTU, and (3) includes an adder that is based on: (a) the System cost of fixed Production O&M expenses for the previous 3 years divided by the System net steam generation for those three years, (b) incremental replacement SO_2 costs for each	(b)	5, 25, 63

		generating unit, adjusted weekly, and (c) incremental replacement NO_X costs for each generating unit, adjusted weekly.		
31, 32, 33	320-321	**Electric Operations and Maintenance Expense** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-4, differ from Form 1 amounts because the formula rate only reflects the non-fuel Production O&M Expenses related to the Designated Generating Unit	(c)	4, 6-11, 15-19, 24, 26-32, 35-39, 44-49, 53-57, 62, 64-66 and 69-72
34	321	**Electric Operations and Maintenance Expense** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-2, differ from Form 1 amounts because the formula rate only reflects the Transmission O&M Expenses related to the Inter-Transmission Investment	(c)	112
35	321	**Electric Operations and Maintenance Expense** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-4, differ from Form 1 amounts because the formula rate only reflects the Transmission O&M Expenses related to the step-up transformers and associated transmission equipment related to the Designated Generating Unit	(c)	93, 107
36	323	**Electric Operations and Maintenance Expenses** Costs used in 4th Rev. RS No. 94, Service Schedules MSS-1 and MSS-2, differ from Form 1 amounts because the formula rates allocate A&G costs using a Labor Ratio	(c)	181-193
37	323	**Electric Operations and Maintenance Expenses** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-4, differ from Form 1 amounts because the formula rate allocate A&G costs using a Labor Ratio	(c)	181-184 and 186-193
38	323	**Electric Operations and Maintenance Expense** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-1, differ from Form 1 amounts because the formula rate only reflects the Insurance Expense related to the intermediate gas and oil units	(c)	185
39	323	**Electric Operations and Maintenance Expense** Costs used in 4th Rev. RS No. 94,	(c)	185

		Service Schedule MSS-4, differ from Form 1 amounts because the formula rate only reflects the Insurance Expense related to the Designated Generating Unit		
40	336	**Depreciation Expense** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-1, differ from Form 1 amounts because the formula rate only reflects the Depreciation Expense related to intermediate gas and oil units, plus the Depreciation Expense related to the step-up transformers and associated transmission equipment related to the intermediate gas and oil units	(f)	2
41	336	**Depreciation Expense** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-2, differ from Form 1 amounts because the formula rate only reflects the Depreciation Expense related to the Inter-Transmission Investment	(f)	7
42	336	**Depreciation Expense** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-4, differ from Form 1 amounts because the formula rate only reflects the monthly Depreciation Expense related to the Designated Generating Unit, plus the Depreciation Expense for the step-up transformers and associated transmission equipment related to the Designated Generating Unit	(f)	2-7
43	336	**Depreciation Expense** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-4, differ from Form 1 amounts because the formula rate only reflects an allocation of the monthly General Plant Depreciation Expense using a Labor Ratio	(f)	10
44	402-403	**Steam-Electric Generating Plant Statistics** Costs used in 4th Rev. RS No. 94, Service Schedule MSS-1, differ from Form 1 amounts because the formula rate only reflects the capacity related to intermediate gas and oil units	All	5

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

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SEE PAGE 109 FOR REQUIRED INFORMATION.

1. None

2. None

3. In November 2012, Entergy Arkansas purchased the Hot Spring Energy Facility, a 620 MW combined-cycle natural gas turbine unit located in Malvern, Arkansas, from KGen Hot Spring LLC for approximately $253 million. The FERC approved the transaction in Docket No. ER12-1102-000. The APSC approved the acquisition in APSC Docket No. 11-069-U. Entergy Arkansas filed journal entries with the FERC in May 2013 in Docket No. EC11-113-000.

4. None. See Entergy Arkansas's 2013 FERC Form 1 Notes to Financial Statements, Note 10 regarding capital leases.

5. Entergy Arkansas joined the Midcontinent Independent System Operator, Inc. (“MISO”) on December 19, 2013. As of that date, the Entergy OATT was cancelled and MISO is the Transmission Provider for transmission service over Entergy Arkansas’s transmission facilities under the MISO Tariff.

6. See Entergy Arkansas's 2013 FERC Form 1 Notes to Financial Statements, Notes 4, 5, 6, and 8.

7. None

8. Fossil operating and clerical employees are represented by the International Brotherhood of Electrical Workers AFL-CIO, Local Unions 647, 750, and 1703. The Company and the Union agreed to a contract effective October 1, 2012 through October 1, 2015. Effective October 1, 2013, the wage increase was 2.0%.

   Transmission, distribution, and utility support employees are represented by the International Brotherhood of Electrical Workers AFL-CIO, Local Unions 647, 750, 1439, and 1703. The Company and the Union agreed to a contract effective October 1, 2012 through October 1, 2015. Effective October 1, 2013, the wage increase was 2.0%.

   Effective April 1, 2013, executive and senior management, middle management, professionals, and non-represented operating, maintenance, and support staff pay increases averaged approximately 1.9%.

   <u>Arkansas Nuclear One</u>

   Operating, maintenance, engineering, technical, and administrative employees are represented by the International Brotherhood of Electrical Workers AFL-CIO, Local Union 647. The Company and the Union agreed to a contract effective March 1, 2012 through March 1, 2015. Effective March 1, 2013, the wage increase was 2.0%.

   Security employees are represented by the United Government Security Officers of America, Local Union 23. The Company and the Union agreed to a contract effective June 21, 2009 through March 31, 2013. The Company and the Union agreed to a new contract effective April 1, 2013 through March 31, 2016. Effective April 1, 2013, the wage increase was 2.0%.

9. See Entergy Corporation and Subsidiaries 2013 Form 10-K Part I, Legal Proceedings.

10. None

11. Not applicable

12. See Entergy Arkansas's 2013 FERC Form 1 Notes to Financial Statements.

13. See Entergy Arkansas’s 2013 FERC Form 1 pages 104 and 105 for Officer and Director changes that occurred in 2013.

14. Not applicable

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	8,903,890,831	8,700,437,756
3	Construction Work in Progress (107)	200-201	217,578,963	212,264,065
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		9,121,469,794	8,912,701,821
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	4,110,040,882	4,117,262,820
6	Net Utility Plant (Enter Total of line 4 less 5)		5,011,428,912	4,795,439,001
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	84,250,776	70,124,176
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		235,575,893	229,196,765
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	-2,074,097	-4,503,409
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		321,900,766	303,824,350
14	Net Utility Plant (Enter Total of lines 6 and 13)		5,333,329,678	5,099,263,351
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		1,777,206	1,777,206
19	(Less) Accum. Prov. for Depr. and Amort. (122)		112,727	106,439
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	-194,861	90,000
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		2,976,050	2,976,050
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		736,912,938	638,577,571
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		741,358,606	643,314,388
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		849,278	9,411,462
36	Special Deposits (132-134)		220,000	210,000
37	Working Fund (135)		88,867	105,857
38	Temporary Cash Investments (136)		122,762,851	24,935,277
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		101,203,460	97,089,419
41	Other Accounts Receivable (143)		94,256,351	71,956,238
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		30,113,390	28,342,982
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		68,875,410	67,276,884
45	Fuel Stock (151)	227	38,687,468	44,975,227
46	Fuel Stock Expenses Undistributed (152)	227	2,706,461	3,914,439
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	131,385,551	127,617,207
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	110,246	85,810

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	21,043,896	21,064,545
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		6,979,063	6,053,403
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		5,395	5,096
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		82,298,469	72,901,912
62	Miscellaneous Current and Accrued Assets (174)		82,205,414	42,107,015
63	Derivative Instrument Assets (175)		15,134	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		723,579,924	561,366,809
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		25,420,461	20,282,461
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	1,093,324,755	1,340,015,387
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	0
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		-15,146	-71,895
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	16,853,250	14,149,701
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		28,835,843	31,498,981
82	Accumulated Deferred Income Taxes (190)	234	581,685,024	716,793,200
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,746,104,187	2,122,667,835
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		8,544,372,395	8,426,612,383

Schedule Page: 110 Line No.: 5 Column: c

Includes removal costs accrual of $18,605,769.

Schedule Page: 110 Line No.: 5 Column: d

Includes removal costs accrual of ($12,245,562).

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2013/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	469,802	469,802
3	Preferred Stock Issued (204)	250-251	116,350,000	116,350,000
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		3,464,414	3,464,414
7	Other Paid-In Capital (208-211)	253	586,782,648	586,782,648
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	1,802,833	1,802,833
11	Retained Earnings (215, 215.1, 216)	118-119	1,131,716,202	991,306,448
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-938,933	-604,472
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	0	0
16	Total Proprietary Capital (lines 2 through 15)		1,836,041,300	1,695,966,007
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,600,000,000	1,525,000,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	533,054,842	282,971,778
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,216,972	626,754
24	Total Long-Term Debt (lines 18 through 23)		2,131,837,870	1,807,345,024
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		59,608,622	130,188,656
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		4,499,082	4,145,062
29	Accumulated Provision for Pensions and Benefits (228.3)		26,399,335	129,115,666
30	Accumulated Miscellaneous Operating Provisions (228.4)		1,247,000	1,676,844
31	Accumulated Provision for Rate Refunds (229)		1,771,913	1,214,767
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		723,770,504	680,712,153
35	Total Other Noncurrent Liabilities (lines 26 through 34)		817,296,456	947,053,148
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		228,160,062	200,964,200
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		175,997,485	65,058,177
41	Customer Deposits (235)		86,512,360	85,198,175
42	Taxes Accrued (236)	262-263	-29,183,241	144,321,074
43	Interest Accrued (237)		34,141,778	46,700,344
44	Dividends Declared (238)		1,718,306	1,718,306
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2013/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		15,211,140	15,068,699
48	Miscellaneous Current and Accrued Liabilities (242)		23,700,067	12,726,628
49	Obligations Under Capital Leases-Current (243)		99,772,934	99,982,180
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		636,030,891	671,737,783
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	38,958,373	40,947,160
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	342,175,689	538,193,894
60	Other Regulatory Liabilities (254)	278	254,147,372	196,714,837
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		1,635,492,991	1,596,621,901
64	Accum. Deferred Income Taxes-Other (283)		852,391,453	932,032,629
65	Total Deferred Credits (lines 56 through 64)		3,123,165,878	3,304,510,421
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		8,544,372,395	8,426,612,383

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

STATEMENT OF INCOME

Quarterly
1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	2,175,606,016	2,111,727,865		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,338,382,943	1,327,968,476		
5	Maintenance Expenses (402)	320-323	189,661,076	175,213,862		
6	Depreciation Expense (403)	336-337	212,094,281	203,174,811		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	-161,986	-159,200		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	17,571,825	19,353,071		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	1,014,303	84,578		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		11,160,904	1,765,144		
13	(Less) Regulatory Credits (407.4)		34,137,842	52,287,391		
14	Taxes Other Than Income Taxes (408.1)	262-263	89,408,531	89,481,096		
15	Income Taxes - Federal (409.1)	262-263	12,884,901	277,546,454		
16	- Other (409.1)	262-263	9,539,248	4,159,598		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	837,629,918	1,489,791,407		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	761,545,563	1,668,223,190		
19	Investment Tax Credit Adj. - Net (411.4)	266	-2,014,476	-2,017,142		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		143	353		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		43,058,351	40,484,059		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,964,546,271	1,906,335,280		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		211,059,745	205,392,585		

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
2,175,606,016	2,111,727,865					2
						3
1,338,382,943	1,327,968,476					4
189,661,076	175,213,862					5
212,094,281	203,174,811					6
-161,986	-159,200					7
17,571,825	19,353,071					8
1,014,303	84,578					9
						10
						11
11,160,904	1,765,144					12
34,137,842	52,287,391					13
89,408,531	89,481,096					14
12,884,901	277,546,454					15
9,539,248	4,159,598					16
837,629,918	1,489,791,407					17
761,545,563	1,668,223,190					18
-2,014,476	-2,017,142					19
						20
						21
143	353					22
						23
43,058,351	40,484,059					24
1,964,546,271	1,906,335,280					25
211,059,745	205,392,585					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		211,059,745	205,392,585		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)		6,286	6,546		
35	Nonoperating Rental Income (418)		120,000			
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-334,242	-138,305		
37	Interest and Dividend Income (419)		30,143,920	15,160,915		
38	Allowance for Other Funds Used During Construction (419.1)		14,549,748	12,441,441		
39	Miscellaneous Nonoperating Income (421)		822,047	806,952		
40	Gain on Disposition of Property (421.1)			71,106		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		45,295,187	28,335,563		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		2,548,998	39,869		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		1,949,653	1,520,647		
46	Life Insurance (426.2)					
47	Penalties (426.3)		114,024	362,552		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,583,447	2,532,316		
49	Other Deductions (426.5)		7,835,729	7,006,251		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		15,031,851	11,461,635		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	9	83		
53	Income Taxes-Federal (409.2)	262-263	48,000	-19,403,000		
54	Income Taxes-Other (409.2)	262-263	1,844,673	2,367,172		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277				
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277				
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		1,892,682	-17,035,745		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		28,370,654	33,909,673		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		82,282,568	73,116,669		
63	Amort. of Debt Disc. and Expense (428)		1,816,333	1,495,994		
64	Amortization of Loss on Reaquired Debt (428.1)		3,223,224	3,249,653		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		72,448	202,138		
68	Other Interest Expense (431)		-5,200,557	12,571,981		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		4,712,130	3,699,136		
70	Net Interest Charges (Total of lines 62 thru 69)		77,481,886	86,937,299		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		161,948,513	152,364,959		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		161,948,513	152,364,959		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		991,306,448	855,675,922
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		162,282,755	152,503,264
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24		238	-6,873,220	(6,873,220)
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-6,873,220	(6,873,220)
30	Dividends Declared-Common Stock (Account 438)			
31		238	-15,000,000	(10,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-15,000,000	(10,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		219	482
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,131,716,202	991,306,448
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,131,716,202	991,306,448
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-604,472	(465,685)
50	Equity in Earnings for Year (Credit) (Account 418.1)		-334,242	(138,305)
51	(Less) Dividends Received (Debit)		219	482
52				
53	Balance-End of Year (Total lines 49 thru 52)		-938,933	(604,472)

Schedule Page: 118 Line No.: 24 Column: c

For the Year Ended December 31, 2013

$100 Preferred Stock:	
4.32% Series, $4.32 per share	$302,400
4.72% Series, $4.72 per share	441,320
4.56% Series, $4.56 per share	342,000
4.56% Series, (1965 Series) $4.56 per share	342,000
6.08% Series, $6.08 per share	608,000
$25 Preferred Stock:	
6.45% Series	4,837,500
Total Preferred Stock Dividends	$6,873,220

Schedule Page: 118 Line No.: 24 Column: d

For the Year Ended December 31, 2012

$100 Preferred Stock:	
4.32% Series, $4.32 per share	$302,400
4.72% Series, $4.72 per share	441,320
4.56% Series, $4.56 per share	342,000
4.56% Series, (1965 Series) $4.56 per share	342,000
6.08% Series, $6.08 per share	608,000
$25 Preferred Stock:	
6.45% Series	4,837,500
Total Preferred Stock Dividends	$6,873,220

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	161,948,513	152,364,959
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	273,576,774	262,937,319
5	Amortization of debt discount and expense and loss on reacquired debt	5,039,557	4,745,647
6			
7			
8	Deferred Income Taxes (Net)	76,084,355	-178,431,783
9	Investment Tax Credit Adjustment (Net)	-2,014,476	-2,017,142
10	Net (Increase) Decrease in Receivables	-26,143,087	-30,870,884
11	Net (Increase) Decrease in Inventory	3,748,042	-5,409,772
12	Net (Increase) Decrease in Allowances Inventory	-24,436	-14,788
13	Net Increase (Decrease) in Payables and Accrued Expenses	-47,927,711	169,580,887
14	Net (Increase) Decrease in Other Regulatory Assets	246,690,632	16,797,455
15	Net Increase (Decrease) in Other Regulatory Liabilities	57,432,535	42,693,762
16	(Less) Allowance for Other Funds Used During Construction	14,549,748	12,441,441
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
19	Working Capital	-28,619,427	26,274,242
20	Other	-394,485,010	-34,581,279
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	310,756,513	411,627,182
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-489,078,856	-361,858,004
27	Gross Additions to Nuclear Fuel	-88,636,517	-215,968,339
28	Gross Additions to Common Utility Plant		-253,042,992
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-14,549,748	-12,441,441
31	Other (provide details in footnote):		
32	Decomissioning tust funds - Net	-8,128,400	-10,333,055
33	Proceeds from sale of nuclear fuel	45,051,834	248,801,341
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-526,242,191	-579,959,608
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-49,600	-2,000
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Counterparty collateral deposit	9,000,000	
54	Changes in money pool receivable - net	-9,495,742	9,326,975
55	Litigation proceeds for reimb. - spent nuclear fuel storage costs	10,270,697	
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-516,516,836	-570,634,633
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	716,595,363	192,346,712
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	716,595,363	192,346,712
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-399,713,420	
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Other		-12,869
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock	-6,873,220	-6,873,220
81	Dividends on Common Stock	-15,000,000	-10,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	295,008,723	175,460,623
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	89,248,400	16,453,172
87			
88	Cash and Cash Equivalents at Beginning of Period	34,452,596	17,999,424
89			
90	Cash and Cash Equivalents at End of period	123,700,996	34,452,596

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

A. CASH FLOW STATEMENT, ADDITIONAL INFORMATION:

Cash and Cash Equivalents at December 31, 2013

Cash (Account 131)	$849,278
Working Fund (Account 135)	88,867
Temporary Cash Investments (Account 136)	122,762,851
Total Cash and Cash Equivalents	$123,700,996
	==========

SUPPLEMENTAL DISCLOSURE OF CASH FLOW STATEMENT (in 000's)

Cash paid during the period for:

Interest – net of amt capitalized	$96,312
Income Taxes	$184,592

B. FERC FORM 1 PRESENTATION COMPARED TO GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The accompanying financial statements have been prepared in accordance with the accounting requirements of the FERC as set forth in the Uniform System of Accounts and accounting releases, which differs from GAAP. Additional comparative data, including the 2012 data for the statement of retained earnings and cash flows, are needed to present the financial position and results of operations in order to satisfy GAAP. In addition, GAAP requires the disclosure of the current and long-term portion of assets and liabilities. In accordance with FERC reporting requirements, the aforementioned disclosures were not included in these financial statements.

As required by the FERC, Entergy Arkansas, Inc. classifies certain items in the balance sheet (primarily the classification of the components of accumulated deferred income taxes, taxes accrued, certain other miscellaneous current and accrued liabilities, maturities of long-term debt, deferred debits, deferred credits, and accumulated depreciation) in a manner different than that required by GAAP.

GAAP requires Entergy Arkansas to consolidate the company from which it leases nuclear fuel, whereas this company is not consolidated for the FERC Form 1 presentation. The significant difference that results from this is the elimination from the GAAP balance sheet of the obligations under capital leases with the nuclear fuel companies and the addition to the GAAP balance sheet of the nuclear fuel companies' credit facility borrowings, commercial paper, and notes payable.

Finally, GAAP requires that Entergy Arkansas consolidate it majority owned subsidiary, Entergy Arkansas Restoration Funding, LLC, whereas the investment in the company is presented in the Form 1 using the equity method. The significant difference that results from this is the inclusion on Entergy Arkansas's GAAP-basis balance sheet of storm cost regulatory assets that are the property of and securitization bonds that are the obligations of the subsidiary.

C. The Notes to the Financial Statements included herein are adapted from the Entergy Corporation and subsidiaries Form 10-K for the Year Ended December 31, 2013. The Form 10-K Notes to the Financial Statements are prepared in conformity with GAAP, and thus may differ in certain instances from the financial statements contained herein.

"Entergy" when used in these Notes means Entergy Corporation and its direct and indirect subsidiaries.

"Registrant Subsidiaries" when used in these Notes means Entergy Arkansas, Inc., Entergy Gulf States Louisiana, L.L.C., Entergy Louisiana, LLC, Entergy Mississippi, Inc., Entergy New Orleans, Inc., Entergy Texas, Inc., and System Energy Resources, Inc.

"Utility" when used in the Notes means Entergy's business segment that generates, transmits, distributes, and sells electric power, with a small amount of natural gas distribution.

"Utility operating companies" when used in these Notes means Entergy Arkansas, Entergy Gulf States Louisiana, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, and Entergy Texas.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates in the Preparation of Financial Statements

In conformity with generally accepted accounting principles in the United States of America, the preparation of Entergy Corporation's consolidated financial statements and the separate financial statements of the Registrant Subsidiaries requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, and expenses and the disclosure of contingent assets and liabilities. Adjustments to the reported amounts of assets and liabilities may be necessary in the future to the extent that future estimates or actual results are different from the estimates used.

Revenues and Fuel Costs

Entergy Arkansas, Entergy Gulf States Louisiana, Entergy Louisiana, Entergy Mississippi, and Entergy Texas generate, transmit, and distribute electric power primarily to retail customers in Arkansas, Louisiana, Louisiana, Mississippi, and Texas, respectively. Entergy Gulf States Louisiana also distributes natural gas to retail customers in and around Baton Rouge, Louisiana. Entergy New Orleans sells both electric power and natural gas to retail customers in the City of New Orleans, except for Algiers, where Entergy Louisiana is the electric power supplier.

Entergy recognizes revenue from electric power and natural gas sales when power or gas is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, Entergy's Utility operating companies accrue an estimate of the revenues for energy delivered since the latest billings. The Utility operating companies calculate the estimate based upon several factors including billings through the last billing cycle in a month, actual generation in the month, historical line loss factors, and prices in effect in Entergy's Utility operating companies' various jurisdictions. Changes are made to the inputs in the estimate as needed to reflect changes in billing practices. Each month the estimated unbilled revenue amounts are recorded as revenue and unbilled accounts receivable, and the prior month's estimate is reversed. Therefore, changes in price and volume differences resulting from factors such as weather affect the calculation of unbilled revenues from one period to the next, and may result in variability in reported revenues from one period to the next as prior estimates are reversed and new estimates recorded.

Entergy records revenue from sales under rates implemented subject to refund less estimated amounts accrued for probable refunds when Entergy believes it is probable that revenues will be refunded to customers based upon the status of the rate proceeding as of the date the financial statements are prepared.

Entergy's Utility operating companies' rate schedules include either fuel adjustment clauses or fixed fuel factors, which allow either current recovery in billings to customers or deferral of fuel costs until the costs are billed to customers. Where the fuel component of revenues is billed based on a pre-determined fuel cost (fixed fuel factor), the fuel factor remains in effect until changed as part of a general rate case, fuel reconciliation, or fixed fuel factor filing. System Energy's operating revenues are intended to recover from Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans operating expenses and capital costs attributable to Grand Gulf. The capital costs are computed by allowing a return on System Energy's common equity funds allocable to its net investment in Grand Gulf, plus System Energy's effective interest cost for its debt allocable to its investment in Grand Gulf.

Accounting for MISO transactions

In December 2013, Entergy joined MISO, a regional transmission organization that maintains functional control over the combined transmission systems of its members and manages one of the largest energy markets in the U.S. In the MISO market, Entergy offers its generation and bids its load into the market on an hourly basis. MISO settles these hourly offers and bids based on locational marginal prices, which is pricing for energy at a given location based on a market clearing price that takes into account physical limitations on the transmission system, generation, and demand throughout the MISO region. MISO evaluates the market participants' energy offers and demand bids to economically and reliably dispatch the entire MISO system. Entergy accounts for these hourly offers and bids, on a net basis, in operating revenues when in a net selling position and in operating expenses when in a net purchasing position.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost. Depreciation is computed on the straight-line basis at rates based on the applicable estimated service lives of the various classes of property. For the Registrant Subsidiaries, the original cost of plant retired or removed, less salvage, is charged to accumulated depreciation. Normal maintenance, repairs, and minor replacement costs are charged to operating expenses. Substantially all of the Registrant Subsidiaries' plant is subject to mortgage liens.

Details of property, plant, and equipment by functional category are presented on FERC Form 1 pages 204-207 and details of accumulated depreciation by functional category are presented on FERC Form 1 page 219.

Depreciation rates on average depreciable property for the Registrant Subsidiaries are shown below:

Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy

2013	2.5%	1.8%	2.5%	2.6%	3.0%	2.5%	2.8%
2012	2.5%	1.8%	2.4%	2.6%	3.0%	2.4%	2.8%
2011	2.6%	1.8%	2.5%	2.6%	3.0%	2.2%	2.8%

As of December 31, 2013, construction expenditures included in accounts payable are $61.9 million for Entergy Arkansas, $13.1 million for Entergy Gulf States Louisiana, $31.1 million for Entergy Louisiana, $2.8 million for Entergy Mississippi, $1.7 million for Entergy New Orleans, $10.9 million for Entergy Texas, and $6.7 million for System Energy. As of December 31, 2012, construction expenditures included in accounts payable are $56.3 million for Entergy Arkansas, $9.7 million for Entergy Gulf States Louisiana, $110.4 million for Entergy Louisiana, $4.8 million for Entergy Mississippi, $1.9 million for Entergy New Orleans, $8.6 million for Entergy Texas, and $13.5 million for System Energy.

Jointly-Owned Generating Stations

Certain Entergy subsidiaries jointly own electric generating facilities with affiliates or third parties. The investments and expenses associated with these generating stations are recorded by the Entergy subsidiaries to the extent of their respective undivided ownership interests. As of December 31, 2013, the subsidiaries' investment and accumulated depreciation in each of these generating stations were as follows:

Generating Stations		Fuel-Type	Total Megawatt Capability (a)	Ownership	Investment	Accumulated Depreciation
					(In Millions)	
Utility business:						
Entergy Arkansas -						
Independence	Unit 1	Coal	838	31.50%	$129	$97
	Common Facilities	Coal		15.75%	$33	$25
White Bluff	Units 1 and 2	Coal	1,637	57.00%	$502	$348
Ouachita (b)	Common Facilities	Gas		66.67%	$169	$144
Entergy Gulf States Louisiana -						
Roy S. Nelson	Unit 6	Coal	551	40.25%	$255	$176
Roy S. Nelson	Unit 6 Common Facilities	Coal		15.92%	$8	$3
Big Cajun 2	Unit 3	Coal	603	24.15%	$143	$102
Ouachita (b)	Common Facilities	Gas		33.33%	$87	$73
Entergy Louisiana -						
Acadia	Common Facilities	Gas		50.00%	$19	$—

Entergy Mississippi -						
Independence	Units 1 and 2 and Common Facilities	Coal	1,679	25.00%	$250	$144
Entergy Texas -						
Roy S. Nelson	Unit 6	Coal	551	29.75%	$183	$113
Roy S. Nelson	Unit 6 Common Facilities	Coal		11.77%	$6	$2
Big Cajun 2	Unit 3	Coal	603	17.85%	$107	$71
System Energy -						
Grand Gulf	Unit 1	Nuclear	1,413	90.00% (c)	$4,696	$2,699

(a) "Total Megawatt Capability" is the dependable load carrying capability as demonstrated under actual operating conditions based on the primary fuel (assuming no curtailments) that each station was designed to utilize.

(b) Ouachita Units 1 and 2 are owned 100% by Entergy Arkansas and Ouachita Unit 3 is owned 100% by Entergy Gulf States Louisiana. The investment and accumulated depreciation numbers above are only for the common facilities and not for the generating units.

(c) Includes a leasehold interest held by System Energy. System Energy's Grand Gulf lease obligations are discussed in Note 10 to the financial statements.

Nuclear Refueling Outage Costs

Nuclear refueling outage costs are deferred during the outage and amortized over the estimated period to the next outage because these refueling outage expenses are incurred to prepare the units to operate for the next operating cycle without having to be taken off line.

Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction by the Registrant Subsidiaries. AFUDC increases both the plant balance and earnings and is realized in cash through depreciation provisions included in the rates charged to customers.

Income Taxes

Entergy Corporation and the majority of its subsidiaries file a United States consolidated federal income tax return. Each tax-paying entity records income taxes as if it were a separate taxpayer and consolidating adjustments are allocated to the tax filing entities in accordance with Entergy's intercompany income tax allocation agreement. Deferred income taxes are recorded for all temporary differences between the book and tax basis of assets and liabilities, and for certain credits available for carryforward.

Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion of the deferred tax assets will not be realized. Deferred tax assets and liabilities are adjusted for the effects of changes in tax laws and rates in the period in which the tax or rate was enacted.

Investment tax credits are deferred and amortized based upon the average useful life of the related property, in accordance with ratemaking treatment.

Accounting for the Effects of Regulation

Entergy's Utility operating companies and System Energy are rate-regulated enterprises whose rates meet three criteria specified in accounting standards. The Utility operating companies and System Energy have rates that (i) are approved by a body (its regulator) empowered to set rates that bind customers; (ii) are cost-based; and (iii) can be charged to and collected from customers. These criteria may also be applied to separable portions of a utility's business, such as the generation or transmission functions, or to specific classes of customers. Because the Utility operating companies and System Energy meet these criteria, each of them capitalizes costs that would otherwise be charged to expense if the rate actions of its regulator make it probable that those costs will be recovered in future revenue. Such capitalized costs are reflected as regulatory assets in the accompanying financial statements. When an enterprise concludes that recovery of a regulatory asset is no longer probable, the regulatory asset must be removed from the entity's balance sheet.

An enterprise that ceases to meet the three criteria for all or part of its operations should report that event in its financial statements. In general, the enterprise no longer meeting the criteria should eliminate from its balance sheet all regulatory assets and liabilities related to the applicable operations. Additionally, if it is determined that a regulated enterprise is no longer recovering all of its costs, it is possible that an impairment may exist that could require further write-offs of plant assets.

Regulatory Asset for Income Taxes

Accounting standards for income taxes provide that a regulatory asset be recorded if it is probable that the currently determinable future increase in regulatory income tax expense will be recovered from customers through future rates. The primary source of Entergy's regulatory asset for income taxes is book depreciation of AFUDC equity that has been capitalized to property, plant, and equipment but for which there is no corresponding tax basis. AFUDC equity is a component of property, plant, and equipment that is included in rate base when the plant is placed in service.

Cash and Cash Equivalents

Entergy considers all unrestricted highly liquid debt instruments with an original or remaining maturity of three months or less at date of purchase to be cash equivalents.

Allowance for Doubtful Accounts

The allowance for doubtful accounts reflects Entergy's best estimate of losses on the accounts receivable balances. The allowance is based on accounts receivable agings, historical experience, and other currently available evidence. Utility operating company customer accounts receivable are written off consistent with approved regulatory requirements.

Investments

Entergy records decommissioning trust funds on the balance sheet at their fair value. Because of the ability of the Registrant Subsidiaries to recover decommissioning costs in rates and in accordance with the regulatory treatment for decommissioning trust funds, the Registrant Subsidiaries record an offsetting amount in other regulatory liabilities/assets to the unrealized gains/(losses) on investment securities. For the portion of River Bend that is not rate-regulated, Entergy Gulf States Louisiana has recorded an offsetting amount in other deferred credits to the unrealized gains/(losses). The assessment of whether an investment in a debt security has suffered an other-than-temporary impairment is based on whether Entergy has the intent to sell or more likely than not will be required to sell the debt security before recovery of its amortized costs. Further, if Entergy does not expect to recover the entire amortized cost basis of the debt security, an other-than-temporary impairment is considered to have occurred and it is measured by the present value of cash flows expected to be collected less the amortized cost basis (credit loss). The assessment of whether an investment in an equity security has suffered an other-than-temporary impairment is based on a number of factors including, first, whether Entergy has the ability and intent to hold the investment to recover its value, the duration and severity of any losses, and, then, whether it is expected that the investment will recover its value within a reasonable period of time. Entergy's trusts are managed by third parties who operate in accordance with agreements that define investment guidelines and place restrictions on the purchases and sales of investments. See Note 17 to the financial statements for details on the decommissioning trust funds.

Derivative Financial Instruments and Commodity Derivatives

The accounting standards for derivative instruments and hedging activities require that all derivatives be recognized at fair value on the balance sheet, either as assets or liabilities, unless they meet various exceptions including the normal purchase, normal sales criteria. The changes in the fair value of recognized derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and the type of hedge transaction.

Contracts for commodities that will be physically delivered in quantities expected to be used or sold in the ordinary course of business, including certain purchases and sales of power and fuel, meet the normal purchase, normal sales criteria and are not recognized on the balance sheet. Revenues and expenses from these contracts are reported on a gross basis in the appropriate revenue and expense categories as the commodities are received or delivered.

For other contracts for commodities in which Entergy is hedging the variability of cash flows related to a variable-rate asset, liability, or forecasted transactions that qualify as cash flow hedges, the changes in the fair value of such derivative instruments are reported in other comprehensive income. To qualify for hedge accounting, the relationship between the hedging instrument and the hedged item must be documented to include the risk management objective and strategy and, at inception and on an ongoing basis, the effectiveness of the hedge in offsetting the changes in the cash flows of the item being hedged. Gains or losses accumulated in other comprehensive income are reclassified to earnings in the periods when the underlying transactions actually occur. The ineffective portions of all hedges are recognized in current-period earnings.

Entergy has determined that contracts to purchase uranium do not meet the definition of a derivative under the accounting standards for derivative instruments because they do not provide for net settlement and the uranium markets are not sufficiently liquid to conclude that forward contracts are readily convertible to cash. If the uranium markets do become sufficiently liquid in the future and Entergy begins to account for uranium purchase contracts as derivative instruments, the fair value of these contracts would be accounted for consistent with Entergy's other derivative instruments.

Fair Values

The estimated fair values of Entergy's financial instruments and derivatives are determined using bid prices, market quotes, and financial modeling. Considerable judgment is required in developing the estimates of fair value. Therefore, estimates are not necessarily indicative of the amounts that Entergy could realize in a current market exchange. Gains or losses realized on financial instruments held by regulated businesses may be reflected in future rates and therefore do not accrue to the benefit or detriment of stockholders. Entergy considers the carrying amounts of most financial instruments classified as current assets and liabilities to be a reasonable estimate of their fair value because of the short maturity of these instruments. See Note 16 to the financial statements for further discussion of fair value.

Impairment of Long-Lived Assets

Entergy periodically reviews long-lived assets held in all of its business segments whenever events or changes in circumstances indicate that recoverability of these assets is uncertain. Generally, the determination of recoverability is based on the undiscounted net cash flows expected to result from such operations and assets. Projected net cash flows depend on the future operating costs associated with the assets, the efficiency and availability of the assets and generating units, and the future market and price for energy over the remaining life of the assets.

Reacquired Debt

The premiums and costs associated with reacquired debt of Entergy's Utility operating companies and System Energy (except that portion allocable to the deregulated operations of Entergy Gulf States Louisiana) are included in regulatory assets and are being amortized over the life of the related new issuances, or over the life of the original debt issuance if the debt is not refinanced, in accordance with ratemaking treatment.

Taxes Imposed on Revenue-Producing Transactions

Governmental authorities assess taxes that are both imposed on and concurrent with a specific revenue-producing transaction between a seller and a customer, including, but not limited to, sales, use, value added, and some excise taxes. Entergy presents these taxes on a net basis, excluding them from revenues, unless required to report them differently by a regulatory authority.

New Accounting Pronouncements

The accounting standard-setting process, including projects between the FASB and the International Accounting Standards Board (IASB) to converge U.S. GAAP and International Financial Reporting Standards, is ongoing and the FASB and the IASB are each currently working on several projects that have not yet resulted in final pronouncements. Final pronouncements that result from these projects could have a material effect on Entergy's future net income, financial position, or cash flows.

NOTE 2. RATE AND REGULATORY MATTERS

Regulatory Assets

Other Regulatory Assets

Regulatory assets represent probable future revenues associated with costs that are expected to be recovered from customers through the regulatory ratemaking process under which the Utility business operates. Details of regulatory assets in FERC account 182.3 are presented on FERC Form 1 page 232.

Fuel and purchased power cost recovery

Entergy Arkansas, Entergy Gulf States Louisiana, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, and Entergy Texas are allowed to recover fuel and purchased power costs through fuel mechanisms included in electric and gas rates that are recorded as fuel cost recovery revenues. The difference between revenues collected and the current fuel and purchased power costs is generally recorded as "Deferred fuel costs" on the Utility operating companies' financial statements. The table below shows the amount of deferred fuel costs as of December 31, 2013 and 2012 that Entergy expects to recover (or return to customers) through fuel mechanisms, subject to subsequent regulatory review.

	2013	2012
	(In Millions)	
Entergy Arkansas	$68.7	$97.3
Entergy Gulf States Louisiana (a)	$109.7	$99.2
Entergy Louisiana (a)	$37.6	$94.6
Entergy Mississippi	$38.1	$26.5
Entergy New Orleans (a)	($19.1)	$1.9

Entergy Texas	($4.1)	($93.3)

(a) 2013 and 2012 include $100.1 million for Entergy Gulf States Louisiana, $68 million for Entergy Louisiana, and $4.1 million for Entergy New Orleans of fuel, purchased power, and capacity costs, which do not currently earn a return on investment and whose recovery periods are indeterminate but are expected to be over a period greater than twelve months.

Entergy Arkansas

Production Cost Allocation Rider

The APSC approved a production cost allocation rider for recovery from customers of the retail portion of the costs allocated to Entergy Arkansas as a result of the System Agreement proceedings, which are discussed in the "**System Agreement Cost Equalization Proceedings**" section below. These costs cause an increase in Entergy Arkansas's deferred fuel cost balance because Entergy Arkansas pays the costs over seven months but collects them from customers over twelve months.

Energy Cost Recovery Rider

Entergy Arkansas's retail rates include an energy cost recovery rider to recover fuel and purchased energy costs in monthly customer bills. The rider utilizes the prior calendar-year energy costs and projected energy sales for the twelve-month period commencing on April 1 of each year to develop an energy cost rate, which is redetermined annually and includes a true-up adjustment reflecting the over- or under-recovery, including carrying charges, of the energy costs for the prior calendar year. The energy cost recovery rider tariff also allows an interim rate request depending upon the level of over- or under-recovery of fuel and purchased energy costs.

In October 2005 the APSC initiated an investigation into Entergy Arkansas's interim energy cost recovery rate. The investigation focused on Entergy Arkansas's 1) gas contracting, portfolio, and hedging practices; 2) wholesale purchases during the period; 3) management of the coal inventory at its coal generation plants; and 4) response to the contractual failure of the railroads to provide coal deliveries. In March 2006 the APSC extended its investigation to cover the costs included in Entergy Arkansas's March 2006 annual energy cost rate filing, and a hearing was held in the APSC investigation in October 2006.

In January 2007 the APSC issued an order in its review of the energy cost rate. The APSC found that Entergy Arkansas failed to maintain an adequate coal inventory level going into the summer of 2005 and that Entergy Arkansas should be responsible for any incremental energy costs that resulted from two outages caused by employee and contractor error. The coal plant generation curtailments were caused by railroad delivery problems and Entergy Arkansas has since resolved litigation with the railroad regarding the delivery problems. The APSC staff was directed to perform an analysis with Entergy Arkansas's assistance to determine the additional fuel and purchased energy costs associated with these findings and file the analysis within sixty days of the order. After a final determination of the costs is made by the APSC, Entergy Arkansas will be directed to refund that amount with interest to its customers as a credit on the energy cost recovery rider. Entergy Arkansas requested rehearing of the order.

In February 2010 the APSC denied Entergy Arkansas's request for rehearing, and held a hearing in September 2010 to determine the amount of damages, if any, that should be assessed against Entergy Arkansas. A decision is pending. Entergy Arkansas expects the amount of damages, if any, to have an immaterial effect on its results of operations, financial position, or cash flows.

The APSC also established a separate docket to consider the resolved railroad litigation, and in February 2010 it established a procedural schedule that concluded with testimony through September 2010. The testimony has been filed, and the APSC will decide the case based on the record in the proceeding.

In January 2014, Entergy Arkansas filed a motion with the APSC relating to its upcoming March 2014 calculation of its revised energy cost rate. In that motion, Entergy Arkansas requested that the APSC authorize Entergy Arkansas to exclude $65.9 million of deferred fuel and purchased energy costs incurred in 2013 from the calculation of its 2014 revised energy cost rate. The $65.9 million is an estimate of the incremental fuel and replacement energy costs that Entergy Arkansas incurred as a result of the ANO stator incident. Entergy Arkansas requested that the APSC authorize Entergy Arkansas to retain that amount in its deferred fuel balance, with recovery to be reviewed in a later period after more information is available regarding various claims associated with the ANO stator incident. The APSC approved Entergy Arkansas's request in February 2014. See the "**ANO Damage and Outage**" section in Note 8 to the financial statements for further discussion of the ANO stator incident.

Retail Rate Proceedings

Filings with the APSC (Entergy Arkansas)

Retail Rates

2013 Base Rate Filing

In March 2013, Entergy Arkansas filed with the APSC for a general change in rates, charges, and tariffs. The filing assumed Entergy Arkansas's transition to MISO in December 2013, and requested a rate increase of $174 million, including $49 million of revenue being transferred from collection in riders to base rates. The filing also proposed a new transmission rider and a capacity cost recovery rider. The filing requested a 10.4% return on common equity. In September 2013, Entergy Arkansas filed testimony reflecting an updated rate increase request of $145 million, with no change to its requested return on common equity of 10.4%. Hearings in the proceeding began in October 2013, and in December 2013 the APSC issued an order. The order authorizes a base rate increase of $81 million and includes an authorized return on common equity of 9.3%. The order allows Entergy Arkansas to amortize its human capital management costs over a three-and-a-half year period, but also orders Entergy Arkansas to file a detailed report of the Arkansas-specific costs, savings and final payroll changes upon conclusion of the human capital management initiative.

The substance of the report will be addressed in Entergy Arkansas's next base rate filing. New rates will be implemented in the first billing cycle of March 2014 and are effective as of January 2014. Additionally, in January 2014, Entergy Arkansas filed a petition for rehearing or clarification of several aspects of the APSC's order, including the 9.3% authorized return on common equity. In February 2014 the APSC granted Entergy Arkansas's petition for the purpose of further consideration.

System Agreement Cost Equalization Proceedings

The Utility operating companies historically have engaged in the coordinated planning, construction, and operation of generating and bulk transmission facilities under the terms of the System Agreement, which is a rate schedule that has been approved by the FERC. Certain of the Utility operating companies' retail regulators and other parties are pursuing litigation involving the System Agreement at the FERC. The proceedings include challenges to the allocation of costs as defined by the System Agreement and allegations of imprudence by the Utility operating companies in their execution of their obligations under the System Agreement.

In June 2005, the FERC issued a decision in System Agreement litigation that had been commenced by the LPSC, and essentially affirmed its decision in a December 2005 order on rehearing. The FERC decision concluded, among other things, that:

- The System Agreement no longer roughly equalizes total production costs among the Utility operating companies.
- In order to reach rough production cost equalization, the FERC imposed a bandwidth remedy by which each company's total annual production costs will have to be within +/- 11% of Entergy System average total annual production costs.
- In calculating the production costs for this purpose under the FERC's order, output from the Vidalia hydroelectric power plant will not reflect the actual Vidalia price for the year but is priced at that year's average price paid by Entergy Louisiana for the exchange of electric energy under Service Schedule MSS-3 of the System Agreement, thereby reducing the amount of Vidalia costs reflected in the comparison of the Utility operating companies' total production costs.
- The remedy ordered by FERC in 2005 required no refunds and became effective based on calendar year 2006 production costs and the first reallocation payments were made in 2007.

The FERC's decision reallocates total production costs of the Utility operating companies whose relative total production costs expressed as a percentage of Entergy System average production costs are outside an upper or lower bandwidth. Under the current circumstances, this will be accomplished by payments from Utility operating companies whose production costs are more than 11% below Entergy System average production costs to Utility operating companies whose production costs are more than the Entergy System average production cost, with payments going first to those Utility operating companies whose total production costs are farthest above the Entergy System average.

The financial consequences of the FERC's decision are determined by the total production cost of each Utility operating company, which are affected by the mix of solid fuel and gas-fired generation available to each company and the costs of natural gas and purchased power. Entergy Louisiana, Entergy Gulf States Louisiana, Entergy Texas, and Entergy Mississippi are more dependent upon gas-fired generation sources than Entergy Arkansas or Entergy New Orleans. Of these, Entergy Arkansas is the least dependent upon gas-fired generation sources. Therefore, increases in natural gas prices generally increased the amount by which Entergy Arkansas's total production costs were below the Entergy System average production costs.

The LPSC, APSC, MPSC, and the Arkansas Electric Energy Consumers appealed the FERC's December 2005 decision to the United States Court of Appeals for the D.C. Circuit. Entergy and the City of New Orleans intervened in the various appeals. The D.C. Circuit issued its decision in April 2008. The D.C. Circuit concluded that the FERC's orders had failed to adequately explain both its conclusion that it was prohibited from ordering refunds for the 20-month period from September 13, 2001 - May 2, 2003 and its determination to implement the bandwidth remedy commencing on January 1, 2006, rather than June 1, 2005. The D.C. Circuit remanded the case to the FERC for further proceedings on these issues.

In October 2011, the FERC issued an order addressing the D.C. Circuit remand on these two issues. On the first issue, the FERC concluded that it did have the authority to order refunds, but decided that it would exercise its equitable discretion and not require refunds for the 20-month period from September 13, 2001 - May 2, 2003. Because the ruling on refunds relied on findings in the interruptible load proceeding, which is discussed in a separate section below, the FERC concluded that the refund ruling will be held in abeyance pending the outcome of the rehearing requests in that proceeding. On the second issue, the FERC reversed its prior decision and ordered that the prospective bandwidth remedy begin on June 1, 2005 (the date of its initial order in the proceeding) rather than January 1, 2006, as it had previously ordered. Pursuant to the October 2011 order, Entergy was required to calculate the additional bandwidth payments for the period June - December 2005 utilizing the bandwidth formula tariff prescribed by the FERC that was filed in a December 2006 compliance filing and accepted by the FERC in an April 2007 order. As is the case with bandwidth remedy payments, these payments and receipts will ultimately be paid by Utility operating company customers to other Utility operating company customers.

In December 2011, Entergy filed with the FERC its compliance filing that provides the payments and receipts among the Utility operating companies pursuant to the FERC's October 2011 order. The filing shows the following payments/receipts among the Utility operating companies:

	Payments (Receipts)
	(In Millions)
Entergy Arkansas	$156
Entergy Gulf States Louisiana	($75)
Entergy Louisiana	$—
Entergy Mississippi	($33)
Entergy New Orleans	($5)

Entergy Texas	($43)

Entergy Arkansas made its payment in January 2012. In February 2012, Entergy Arkansas filed for an interim adjustment to its production cost allocation rider requesting that the $156 million payment be collected from customers over the 22-month period from March 2012 through December 2013. In March 2012 the APSC issued an order stating that the payment can be recovered from retail customers through the production cost allocation rider, subject to refund. The LPSC and the APSC have requested rehearing of the FERC's October 2011 order. In December 2013 the LPSC filed a petition for a writ of mandamus at the United States Court of Appeals for the D.C. Circuit. In its petition, the LPSC requested that the D.C. Circuit issue an order compelling the FERC to issue a final order on pending rehearing requests. In its response to the LPSC petition, the FERC committed to rule on the pending rehearing request before the end of February. In January 2014 the D.C. Circuit denied the LPSC's petition. The APSC, the LPSC, the PUCT, and other parties intervened in the December 2011 compliance filing proceeding, and the APSC and the LPSC also filed protests.

Calendar Year 2013 Production Costs

The liabilities and assets for the preliminary estimate of the payments and receipts required to implement the FERC's remedy based on calendar year 2013 production costs were recorded in December 2013, based on certain year-to-date information. The preliminary estimate was recorded based on the following estimate of the payments/receipts among the Utility operating companies for 2014.

	2014 Payments (Receipts)
	(In Millions)
Entergy Gulf States Louisiana	$—
Entergy Louisiana	$—
Entergy Mississippi	$—
Entergy New Orleans	($16)
Entergy Texas	$16

The actual payments/receipts for 2014, based on calendar year 2013 production costs, will not be calculated until the Utility operating companies' 2013 FERC Form 1s have been filed. Once the calculation is completed, it will be filed at the FERC. The level of any payments and receipts is significantly affected by a number of factors, including, among others, weather, the price of alternative fuels, the operating characteristics of the Entergy System generating fleet, and multiple factors affecting the calculation of the non-fuel related revenue requirement components of the total production costs, such as plant investment. Entergy Arkansas is no longer a participant in the System Agreement and is not part of the calendar year 2013 production costs calculation.

Rough Production Cost Equalization Rates

Each May since 2007 Entergy has filed with the FERC the rates to implement the FERC's orders in the System Agreement proceeding. These filings show the following payments/receipts among the Utility operating companies are necessary to achieve rough production cost equalization as defined by the FERC's orders:

	Payments (Receipts)						
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
				(In Millions)			
Entergy Arkansas	$252	$252	$390	$41	$77	$41	$—
Entergy Gulf States Louisiana	($120)	($124)	($107)	$—	($12)	$—	$—
Entergy Louisiana	($91)	($36)	($140)	($22)	$—	($41)	$—
Entergy Mississippi	($41)	($20)	($24)	($19)	($40)	$—	$—
Entergy New Orleans	$—	($7)	$—	$—	($25)	$—	($15)
Entergy Texas	($30)	($65)	($119)	$—	$—	$—	$15

The APSC has approved a production cost allocation rider for recovery from customers of the retail portion of the costs allocated to Entergy Arkansas. Entergy Texas proposed a rough production cost equalization adjustment rider in its September 2013 rate filing, which is pending. Management believes that any changes in the allocation of production costs resulting from the FERC's decision and related retail proceedings should result in similar rate changes for retail customers, subject to specific circumstances that have caused trapped costs. See "2007 Rate Filing Based on Calendar Year 2006 Production Costs**"** below, however, for a discussion of a FERC decision that could result in trapped costs at Entergy Arkansas related to a contract with AmerenUE.

Entergy Arkansas and, for December 2012 and 2013, Entergy Texas, record accounts payable and Entergy Gulf States Louisiana, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, and Entergy Texas record accounts receivable to reflect the rough production cost equalization payments and receipts required to implement the FERC's remedy. Entergy Arkansas and, for December 2012 and 2013, Entergy Texas, record a corresponding regulatory asset for the right to collect the payments from customers, and Entergy Gulf States Louisiana, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, and Entergy Texas record corresponding regulatory liabilities for their obligations to pass the receipts on to customers. The regulatory asset and liabilities are shown as "System Agreement cost equalization" on the respective balance sheets.

2007 Rate Filing Based on Calendar Year 2006 Production Costs

Several parties intervened in the 2007 rate proceeding at the FERC, including the APSC, the MPSC, the Council, and the LPSC, which also filed protests. The PUCT also intervened. Intervenor testimony was filed in which the intervenors and also the FERC Staff advocated a number of positions on issues that affect the level of production costs the individual Utility operating companies are permitted to reflect in the bandwidth calculation, including the level of depreciation and decommissioning expense for nuclear facilities. The effect of the various positions would be to reallocate costs among the Utility operating companies. The Utility operating companies filed rebuttal testimony explaining why the bandwidth payments are properly recoverable under the AmerenUE contract, and explaining why the positions of FERC Staff and intervenors on the other issues should be rejected. A hearing in this proceeding concluded in July 2008, and the ALJ issued an initial decision in September 2008. The ALJ's initial decision concluded, among other things, that: (1) the decisions to not exercise Entergy Arkansas's option to purchase the Independence plant in 1996 and 1997 were prudent; (2) Entergy Arkansas properly flowed a portion of the bandwidth payments through to AmerenUE in accordance with the wholesale power contract; and (3) the level of nuclear depreciation and decommissioning expense reflected in the bandwidth calculation should be calculated based on NRC-authorized license life, rather than the nuclear depreciation and decommissioning expense authorized by the retail regulators for purposes of retail ratemaking. Following briefing by the parties, the matter was submitted to the FERC for decision. On January 11, 2010, the FERC issued its decision both affirming and overturning certain of the ALJ's rulings, including overturning the decision on nuclear depreciation and decommissioning expense. The FERC's conclusion related to the AmerenUE contract does not permit Entergy Arkansas to recover a portion of its bandwidth payment from AmerenUE. The Utility operating companies requested rehearing of that portion of the decision and requested clarification on certain other portions of the decision.

AmerenUE argued that its wholesale power contract with Entergy Arkansas, pursuant to which Entergy Arkansas sells power to AmerenUE, does not permit Entergy Arkansas to flow through to AmerenUE any portion of Entergy Arkansas's bandwidth payment. The AmerenUE contract expired in August 2009. In April 2008, AmerenUE filed a complaint with the FERC seeking refunds, plus interest, in the event the FERC ultimately determines that bandwidth payments are not properly recovered under the AmerenUE contract. In response to the FERC's decision discussed in the previous paragraph, Entergy Arkansas recorded a regulatory provision in the fourth quarter 2009 for a potential refund to AmerenUE.

In May 2012, the FERC issued an order on rehearing in the proceeding. The order may result in the reallocation of costs among the Utility operating companies, although there are still FERC decisions pending in other System Agreement proceedings that could affect the rough production cost equalization payments and receipts. The FERC directed Entergy, within 45 days of the issuance of a pending FERC order on rehearing regarding the functionalization of costs in the 2007 rate filing, to file a comprehensive bandwidth recalculation report showing updated payments and receipts in the 2007 rate filing proceeding. The May 2012 FERC order also denied Entergy's request for rehearing regarding the AmerenUE contract and ordered Entergy Arkansas to refund to AmerenUE the rough production cost equalization payments collected from AmerenUE. Under the terms of the FERC's order a refund of $30.6 million, including interest, was made in June 2012. Entergy and the LPSC appealed certain aspects of the FERC's decisions to the U.S. Court of Appeals for the D.C. Circuit. On December 7, 2012, the D.C. Circuit dismissed Entergy's petition for review as premature because Entergy filed a rehearing request of the May 2012 FERC order and that rehearing request is still pending. The court also ordered that the LPSC's appeal be held in abeyance and that the parties file motions to govern further proceedings within 30 days of the FERC's completion of the ongoing "Entergy bandwidth proceedings." On October 16, 2013, the FERC issued two orders related to this proceeding. The first order provided clarification with regard to the derivation of the ratio that should be used to functionalize net operating loss carryforwards for purposes of the annual bandwidth filings. The second order denied Entergy's request for rehearing of the FERC's prior determination that interest should be included on recalculated payment and receipt amounts required in this particular proceeding due to the length of time that had passed. Entergy subsequently appealed certain aspects of the FERC's decisions to the U.S. Court of Appeals for the D.C. Circuit. On January 23, 2014, the D.C. Circuit returned the LPSC's appeal to the active docket and consolidated it with Entergy's petition for appellate review. The appeals are pending.

2008 Rate Filing Based on Calendar Year 2007 Production Costs

Several parties intervened in the 2008 rate proceeding at the FERC, including the APSC, the LPSC, and AmerenUE, which also filed protests. Several other parties, including the MPSC and the City Council, intervened in the proceeding without filing a protest. In direct testimony filed in January 2009, certain intervenors and the FERC staff advocated a number of positions on issues that affect the level of production costs the individual Utility operating companies are permitted to reflect in the bandwidth calculation, including the level of depreciation and decommissioning expense for the nuclear and fossil-fueled generating facilities. The effect of these various positions would be to reallocate costs among the Utility operating companies. In addition, three issues were raised alleging imprudence by the Utility operating companies, including whether the Utility operating companies had properly reflected generating units' minimum operating levels for purposes of making unit commitment and dispatch decisions, whether Entergy Arkansas's sales to third parties from its retained share of the Grand Gulf nuclear facility were reasonable, prudent, and non-discriminatory, and whether Entergy Louisiana's long-term Evangeline gas purchase contract was prudent and reasonable.

The parties reached a partial settlement agreement of certain of the issues initially raised in this proceeding. The partial settlement agreement was conditioned on the FERC accepting the agreement without modification or condition, which the FERC did in August 2009. A hearing on the remaining issues in the proceeding was completed in June 2009, and in September 2009 the ALJ issued an initial decision. The initial decision affirms Entergy's position in the filing, except for two issues that may result in a reallocation of costs among the Utility operating companies. In October 2011 the FERC issued an order on the ALJ's initial decision. The FERC's order resulted in a minor reallocation of payments/receipts among the Utility operating companies on one issue in the 2008 rate filing. Entergy made a compliance filing in December 2011 showing the updated payment/receipt amounts. The LPSC filed a protest in response to the compliance filing. In January 2013 the FERC issued an order accepting Entergy's compliance filing. In the January 2013 order the FERC required Entergy to include interest on the recalculated bandwidth payment and receipt amounts for the period from June 1, 2008 until the date of the Entergy intra-system bill that will reflect the bandwidth recalculation amounts for calendar year 2007. In February 2013, Entergy filed a request for rehearing of the FERC's ruling requiring interest. In March 2013 the LPSC filed a petition for review with the U.S. Court of Appeals for the Fifth Circuit seeking appellate review of the FERC's earlier orders addressing the ALJ's initial decision. The Fifth Circuit has scheduled the LPSC petition for oral argument in March 2014.

2009 Rate Filing Based on Calendar Year 2008 Production Costs

Several parties intervened in the 2009 rate proceeding at the FERC, including the LPSC and Ameren, which also filed protests. In July 2009 the FERC accepted Entergy's proposed rates for filing, effective June 1, 2009, subject to refund, and set the proceeding for hearing and settlement procedures. Settlement procedures were terminated and a hearing before the ALJ was held in April 2010. In August 2010 the ALJ issued an initial decision. The initial decision substantially affirms Entergy's position in the filing, except for one issue that may result in some reallocation of costs among the Utility operating companies. The LPSC, the FERC trial staff, and Entergy submitted briefs on exceptions in the proceeding. In May 2012 the FERC issued an order affirming the ALJ's initial decision, or finding certain issues in that decision moot. Rehearing and clarification of FERC's order have been requested. In January 2013 the LPSC filed a protest of Entergy's July 2012 compliance filing submitted in response to the FERC's May 2012 order. In October 2013 the FERC issued orders denying the LPSC's rehearing request with respect to the FERC's May 2012 order and addressing Entergy's compliance filing implementing the FERC's directives in the May 2012 order. The compliance filing order referred to guidance provided in a separate order issued on that same day in the 2007 rate proceeding with respect to the ratio used to functionalize net operating loss carryforwards for bandwidth purposes and directed Entergy to make an additional compliance filing in the 2009 rate proceeding consistent with the guidance provided in that order. In November 2013 the LPSC sought rehearing of the FERC's October 2013 order and Entergy submitted its compliance filing implementing the FERC's directives in the October 2013 order.

Comprehensive Bandwidth Recalculation for 2007, 2008, and 2009 Rate Filing Proceedings

Entergy has committed to file a comprehensive bandwidth recalculation report reflecting the updated payment/receipt amounts in the 2007, 2008, and 2009 rate filing proceedings mentioned above in compliance with the applicable FERC orders. It is probable that these proceedings will result in a reallocation of payments/receipts among the Utility operating companies to achieve production cost equalization as defined by the FERC orders. Based on the progress of the proceedings during the fourth quarter of 2013, Entergy was able to estimate the following range for these payments (receipts) as of December 31, 2013:

	Payments (Receipts)	
	Low	**High**
	(In Millions)	
Entergy Arkansas	$30	$40
Entergy Gulf States Louisiana	($15)	($24)
Entergy Louisiana	($17)	($25)
Entergy Mississippi	$15	$25
Entergy New Orleans	($1)	($1)
Entergy Texas	($12)	($15)

The Utility operating companies recorded payables to/receivables from associated companies based on the low end of the estimated range. Any payments required by the Utility operating companies as a result of these rate filings are expected to be recoverable from customers and any receipts are expected to be credited to customers. Therefore, offsetting regulatory assets/liabilities were also recorded. There is still significant uncertainty regarding the final outcome of these proceedings. As further progress is made, the estimates of the payments/receipts may change. As is the case with bandwidth remedy, these payments and receipts will ultimately be paid by Utility operating company customers to other Utility operating company customers.

2010 Rate Filing Based on Calendar Year 2009 Production Costs

In May 2010, Entergy filed with the FERC the 2010 rates in accordance with the FERC's orders in the System

Agreement proceeding, and supplemented the filing in September 2010. Several parties intervened in the proceeding at the FERC, including the LPSC and the City Council, which also filed protests. In July 2010 the FERC accepted Entergy's proposed rates for filing, effective June 1, 2010, subject to refund, and set the proceeding for hearing and settlement procedures. Settlement procedures have been terminated, and the ALJ scheduled hearings to begin in March 2011. Subsequently, in January 2011 the ALJ issued an order directing the parties and FERC Staff to show cause why this proceeding should not be stayed pending the issuance of FERC decisions in the prior production cost proceedings currently before the FERC on review. In March 2011 the ALJ issued an order placing this proceeding in abeyance. In October 2013 the FERC issued an order granting clarification and denying rehearing with respect to its October 2011 rehearing order in this proceeding. The FERC clarified that in a bandwidth proceeding parties can challenge erroneous inputs, implementation errors, or prudence of cost inputs, but challenges to the bandwidth formula itself must be raised in a Federal Power Act section 206 complaint or section 205 filing. Subsequently in October 2013 the presiding ALJ lifted the stay order holding in abeyance the hearing previously ordered by the FERC and directing that the remaining issues proceed to a hearing on the merits. The hearing is scheduled for March 2014.

2011 Rate Filing Based on Calendar Year 2010 Production Costs

In May 2011, Entergy filed with the FERC the 2011 rates in accordance with the FERC's orders in the System Agreement proceeding. Several parties intervened in the proceeding at the FERC, including the LPSC, which also filed a protest. In July 2011 the FERC accepted Entergy's proposed rates for filing, effective June 1, 2011, subject to refund, set the proceeding for hearing procedures, and then held those procedures in abeyance pending FERC decisions in the prior production cost proceedings currently before the FERC on review. In January 2014 the LPSC filed a petition for a writ of mandamus at the United States Court of Appeals for the Fifth Circuit. In its petition, the LPSC requested that the Fifth Circuit issue an order compelling the FERC to issue a final order in several proceedings related to the System Agreement, including the 2011 rate filing based on calendar year 2010 production costs and the 2012 and 2013 rate filings discussed below.

2012 Rate Filing Based on Calendar Year 2011 Production Costs

In May 2012, Entergy filed with the FERC the 2012 rates in accordance with the FERC's orders in the System Agreement proceeding. Several parties intervened in the proceeding at the FERC, including the LPSC, which also filed a protest. In August 2012 the FERC accepted Entergy's proposed rates for filing, effective June 2012, subject to refund, set the proceeding for hearing procedures, and then held those procedures in abeyance pending FERC decisions in the prior production cost proceedings currently before the FERC on review.

2013 Rate Filing Based on Calendar Year 2012 Production Costs

In May 2013, Entergy filed with the FERC the 2013 rates in accordance with the FERC's orders in the System Agreement proceeding. Several parties intervened in the proceeding at the FERC, including the LPSC, which also filed a protest. The City Council intervened and filed comments related to including the outcome of a related FERC proceeding in the 2013 cost equalization calculation. In August 2013 the FERC issued an order accepting the 2013 rates, effective

June 1, 2013, subject to refund, set the proceeding for hearing procedures, and then held those procedures in abeyance pending FERC decisions in the prior production cost proceedings currently before the FERC on review.

Interruptible Load Proceeding

In April 2007, the U.S. Court of Appeals for the D.C. Circuit issued its opinion in the LPSC's appeal of the FERC's March 2004 and April 2005 orders related to the treatment under the System Agreement of the Utility operating companies' interruptible loads. In its opinion the D.C. Circuit concluded that the FERC (1) acted arbitrarily and capriciously by allowing the Utility operating companies to phase-in the effects of the elimination of the interruptible load over a 12-month period of time; (2) failed to adequately explain why refunds could not be ordered under Section 206(c) of the Federal Power Act; and (3) exercised appropriately its discretion to defer addressing the cost of sulfur dioxide allowances until a later time. The D.C. Circuit remanded the matter to the FERC for a more considered determination on the issue of refunds. The FERC issued its order on remand in September 2007, in which it directed Entergy to make a compliance filing removing all interruptible load from the computation of peak load responsibility commencing April 1, 2004 and to issue any necessary refunds to reflect this change. In addition, the order directed the Utility operating companies to make refunds for the period May 1995 through July 1996. In November 2007 the Utility operating companies filed a refund report describing the refunds to be issued pursuant to the FERC's orders. The LPSC filed a protest to the refund report in December 2007, and the Utility operating companies filed an answer to the protest in January 2008. The refunds were made in October 2008 by the Utility operating companies that owed refunds to the Utility operating companies that were due a refund under the decision. The APSC and the Utility operating companies appealed the FERC decisions to the D.C. Circuit. Because of its refund obligation to its customers as a result of this proceeding and a related LPSC proceeding, Entergy Louisiana recorded provisions during 2008 of approximately $16 million, including interest, for rate refunds. The refunds were made in the fourth quarter 2009.

Following the filing of petitioners' initial briefs, the FERC filed a motion requesting the D.C. Circuit hold the appeal of the FERC's decisions ordering refunds in the interruptible load proceeding in abeyance and remand the record to the FERC. The D.C. Circuit granted the FERC's unopposed motion in June 2009. In December 2009 the FERC established a paper hearing to determine whether the FERC had the authority and, if so, whether it would be appropriate to order refunds resulting from changes in the treatment of interruptible load in the allocation of capacity costs by the Utility operating companies. In August 2010 the FERC issued an order stating that it has the authority and refunds are appropriate. The APSC, MPSC, and Entergy requested rehearing of the FERC's decision. In June 2011 the FERC issued an order granting rehearing in part and denying rehearing in part, in which the FERC determined to invoke its discretion to deny refunds. The FERC held that in this case where "the Entergy system as a whole collected the proper level of revenue, but, as was later established, incorrectly allocated peak load responsibility among the various Entergy operating companies….the Commission will apply here our usual practice in such cases, invoking our equitable discretion to not order refunds, notwithstanding our authority to do so." The LPSC has requested rehearing of the FERC's June 2011 decision. In October 2011 the FERC issued an "Order Establishing Paper Hearing" inviting parties that oppose refunds to file briefs within 30 days addressing the LPSC's argument that FERC precedent supports refunds under the circumstances present in this proceeding. Parties that favor refunds were then invited to file reply briefs within 21 days of the date that the initial briefs are due. Briefs were submitted and the matter is pending.

In September 2010 the FERC had issued an order setting the refund report filed in the proceeding in November 2007 for hearing and settlement judge procedures. In May 2011, Entergy filed a settlement agreement that resolved all issues relating to the refund report set for hearing. In June 2011 the settlement judge certified the settlement as uncontested and the settlement agreement is currently pending before the FERC. In July 2011, Entergy filed an amended/corrected refund report and a motion to defer action on the settlement agreement until after the FERC rules on the LPSC's rehearing request regarding the June 2011 decision denying refunds.

Prior to the FERC's June 2011 order on rehearing, Entergy Arkansas filed an application in November 2010 with the APSC for recovery of the refund that it paid. The APSC denied Entergy Arkansas's application, and also denied Entergy Arkansas's petition for rehearing. If the FERC were to order Entergy Arkansas to pay refunds on rehearing in the interruptible load proceeding the APSC's decision would trap FERC-approved costs at Entergy Arkansas with no regulatory-approved mechanism to recover them. In August 2011, Entergy Arkansas filed a complaint in the United States District Court for the Eastern District of Arkansas asking for a declaratory judgment that the rejection of Entergy Arkansas's application by the APSC is preempted by the Federal Power Act. The APSC filed a motion to dismiss the complaint. In April 2012 the United States district court dismissed Entergy Arkansas's complaint without prejudice stating that Entergy Arkansas's claim is not ripe for adjudication and that Entergy Arkansas did not have standing to bring suit at this time.

In March 2013 the FERC issued an order denying the LPSC's request for rehearing of the FERC's June 2011 order wherein the FERC concluded it would exercise its discretion and not order refunds in the interruptible load proceeding. Based on its review of the LPSC's request for rehearing and the briefs filed as part of the paper hearing established in October 2011, the FERC affirmed its earlier ruling and declined to order refunds under the circumstances of the case. In May 2013 the LPSC filed a petition for review with the U.S. Court of Appeals for the D.C. Circuit seeking review of FERC prior orders in the Interruptible Load Proceeding that concluded that the FERC would exercise its discretion and not order refunds in the proceeding. The appeal is pending.

Entergy Arkansas Opportunity Sales Proceeding

In June 2009, the LPSC filed a complaint requesting that the FERC determine that certain of Entergy Arkansas's sales of electric energy to third parties: (a) violated the provisions of the System Agreement that allocate the energy generated by Entergy System resources, (b) imprudently denied the Entergy System and its ultimate consumers the benefits of low-cost Entergy System generating capacity, and (c) violated the provision of the System Agreement that prohibits sales to third parties by individual companies absent an offer of a right-of-first-refusal to other Utility operating companies. The LPSC's complaint challenges sales made beginning in 2002 and requests refunds. On July 20, 2009, the Utility operating companies filed a response to the complaint requesting that the FERC dismiss the complaint on the merits without hearing because the LPSC has failed to meet its burden of showing any violation of the System Agreement and failed to produce any evidence of imprudent action by the Entergy System. In their response, the Utility operating companies explained that the System Agreement clearly contemplates that the Utility operating companies may make sales to third parties for their own account, subject to the requirement that those sales be included in the load (or load shape) for the applicable Utility operating company. The response further explains that the FERC already has determined that Entergy Arkansas's short-term wholesale sales did not trigger the "right-of-first-refusal" provision of the System Agreement. While the D.C. Circuit recently determined that the "right-of-first-refusal" issue was not properly before the FERC at the time of its earlier decision on the issue, the LPSC has raised no additional claims or facts that would warrant the FERC reaching a different conclusion.

The LPSC filed direct testimony in the proceeding alleging, among other things, (1) that Entergy violated the System Agreement by permitting Entergy Arkansas to make non-requirements sales to non-affiliated third parties rather than making such energy available to the other Utility operating companies' customers; and (2) that over the period 2000 - 2009, these non-requirements sales caused harm to the Utility operating companies' customers and these customers should be compensated for this harm by Entergy. In subsequent testimony, the LPSC modified its original damages claim in favor of quantifying damages by re-running intra-system bills. The Utility operating companies believe the LPSC's allegations are without merit. A hearing in the matter was held in August 2010.

In December 2010, the ALJ issued an initial decision. The ALJ found that the System Agreement allowed for Entergy Arkansas to make the sales to third parties but concluded that the sales should be accounted for in the same manner as joint account sales. The ALJ concluded that "shareholders" should make refunds of the damages to the Utility operating companies, along with interest. Entergy disagreed with several aspects of the ALJ's initial decision and in January 2011 filed with the FERC exceptions to the decision.

The FERC issued a decision in June 2012 and held that, while the System Agreement is ambiguous, it does provide authority for individual Utility operating companies to make opportunity sales for their own account and Entergy Arkansas made and priced these sales in good faith. The FERC found, however, that the System Agreement does not provide authority for an individual Utility operating company to allocate the energy associated with such opportunity sales as part of its load, but provides a different allocation authority. The FERC further found that the after-the-fact accounting methodology used to allocate the energy used to supply the sales was inconsistent with the System Agreement. Quantifying the effect of the FERC's decision will require re-running intra-system bills for a ten-year period, and the FERC in its decision established further hearing procedures to determine the calculation of the effects. In July 2012, Entergy and the LPSC filed requests for rehearing of the FERC's June 2012 decision, which are pending with the FERC.

As required by the procedural schedule established in the calculation proceeding, Entergy filed its direct testimony that included a proposed illustrative re-run, consistent with the directives in FERC's order, of intra-system bills for 2003, 2004, and 2006, the three years with the highest volume of opportunity sales. Entergy's proposed illustrative re-run of intra-system bills shows that the potential cost for Entergy Arkansas would be up to $12 million for the years 2003, 2004, and 2006, and the potential benefit would be significantly less than that for each of the other Utility operating companies. Entergy's proposed illustrative re-run of the intra-system bills also shows an offsetting potential benefit to Entergy Arkansas for the years 2003, 2004, and 2006 resulting from the effects of the FERC's order on System Agreement Service Schedules MSS-1, MSS-2, and MSS-3, and the potential offsetting cost would be significantly less than that for each of the other Utility operating companies. Entergy provided to the LPSC an illustrative intra-system bill recalculation as specified by the LPSC for the years 2003, 2004, and 2006, and the LPSC then filed answering testimony in December 2012. In its testimony the LPSC claims that the damages that should be paid by Entergy Arkansas to the other Utility operating company's customers for 2003, 2004, and 2006 are $42 million to Entergy Gulf States, Inc., $7 million to Entergy Louisiana, $23 million to Entergy Mississippi, and $4 million to Entergy New Orleans. The FERC staff and certain intervenors filed direct and answering testimony in February 2013. In April 2013, Entergy filed its rebuttal testimony in that proceeding, including a revised illustrative re-run of the intra-system bills for the years 2003, 2004, and 2006. The revised calculation determines the re-pricing of the opportunity sales based on consideration of moveable resources only and the removal of exchange energy received by Entergy Arkansas, which increases the potential cost for Entergy Arkansas over the three years 2003, 2004, and 2006 by $2.3 million from the potential costs identified in the Utility operating companies' prior filings in September and October 2012. A hearing was held in May 2013 to quantify the effect of repricing the opportunity sales in accordance with the FERC's decision.

In August 2013 the presiding judge issued an initial decision. The initial decision concludes that the methodology proposed by the LPSC, rather than the methodologies proposed by Entergy or the FERC Staff, should be used to calculate the payments that Entergy Arkansas is to make to the other Utility operating companies. The initial decision also concludes that the other System Agreement service schedules should not be adjusted and that payments by Entergy Arkansas should not be reflected in the rough production cost equalization bandwidth calculations for the applicable years. The initial decision does recognize that the LPSC's methodology would result in an inequitable windfall to the other Utility operating companies and, therefore, concludes that any payments by Entergy Arkansas should be reduced by 20%. The Utility operating companies are currently analyzing the effects of the initial decision. The LPSC, APSC, City Council, and FERC staff filed briefs on exceptions and/or briefs opposing exceptions. Entergy filed a brief on exceptions requesting that FERC reverse the initial decision and a brief opposing certain exceptions taken by the LPSC and FERC staff. The FERC's review of the initial decision is pending. No payments will be made or received by the Utility operating companies until the FERC issues an order reviewing the initial decision and Entergy submits a subsequent filing to comply with that order.

Storm Cost Recovery Filings with Retail Regulators

Entergy Arkansas

Entergy Arkansas December 2012 Winter Storm

In December 2012 a severe winter storm consisting of ice, snow, and high winds caused significant damage to Entergy Arkansas's distribution lines, equipment, poles, and other facilities. Total restoration costs for the repair and/or replacement of Entergy Arkansas's electrical facilities in areas damaged from the winter storm were $63 million, including costs recorded as regulatory assets of approximately $22 million. In the Entergy Arkansas 2013 rate case, the APSC approved inclusion of the construction spending in rate base and approved an increase in the normal storm cost accrual, which will effectively amortize the regulatory asset over a five-year period.

NOTE 3. INCOME TAXES

Details regarding income taxes are presented on FERC Form 1 pages 261-267 and 272-277.

Carryovers

The Registrant Subsidiaries' estimated tax attributes carryovers and their expiration dates as of December 31, 2013 are as follows:

	Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
Federal net operating losses	$1.2 billion	$280 million	$2 billion	$82 million	$56 million	—	$583 million
Year(s) of expiration	2029-2031	2029-2032	2028-2033	2029-2032	2030-2032	N/A	2029-2032
State net operating losses	$109 million	$685 million	$2.8 billion	—	$23 million	—	—
Year(s) of expiration	2024-2026	2025-2027	2024-2027	N/A	2026-2027	N/A	N/A
Misc. federal credits	$2 million	$1 million	$3 million	$1 million	$1 million	—	$2 million
Year(s) of expiration	2024-2032	2024-2032	2026-2032	2024-2032	2024-2032	N/A	2024-2032
State credits	—	—	—	$12.4 million	—	$3.9 million	$18.8 million
Year(s) of expiration	N/A	N/A	N/A	2014-2018	N/A	2014-2027	2015-2018

As a result of the accounting for uncertain tax positions, the amount of the deferred tax assets reflected in the financial statements is less than the amount of the tax effect of the federal and state net operating loss carryovers and tax credit carryovers.

Unrecognized tax benefits

Accounting standards establish a "more-likely-than-not" recognition threshold that must be met before a tax benefit can be recognized in the financial statements. If a tax deduction is taken on a tax return, but does not meet the more-likely-than-not recognition threshold, an increase in income tax liability, above what is payable on the tax return, is required to be recorded.

A reconciliation of the Registrant Subsidiaries' beginning and ending amount of unrecognized tax benefits for 2013, 2012, and 2011 is as follows:

2013	Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy

				(In Thousands)			
Gross balance at January 1, 2013	$344,669	$465,721	$536,673	$16,841	$52,018	$13,954	$260,346
Additions based on tax positions related to the current year	6,427	7,276	10,611	957	583	2,170	4,170
Additions for tax positions of prior years	1,228	7,189	118,025	401	3,506	587	8,391
Reductions for tax positions of prior years	(3,943)	(15,045)	(38,428)	(1,941)	(962)	(4,186)	(967)
Settlements	(668)	(66)	(15,276)	(72)	(3,466)	492	(6,755)
Gross balance at December 31, 2013	347,713	465,075	611,605	16,186	51,679	13,017	265,185
Offsets to gross unrecognized tax benefits:							
Loss carryovers	(345,674)	(136,151)	(611,605)	(16,186)	(22,078)	(266)	(225,286)
Unrecognized tax benefits net of unused tax attributes and payments	$2,039	$328,924	$—	$—	$29,601	$12,751	$39,899

2012	**Entergy Arkansas**	**Entergy Gulf States Louisiana**	**Entergy Louisiana**	**Entergy Mississippi**	**Entergy New Orleans**	**Entergy Texas**	**System Energy**
				(In Thousands)			
Gross balance at January 1, 2012	$335,493	$390,493	$446,187	$11,052	$56,052	$19,225	$281,183
Additions based on tax positions related to the current year	10,409	8,974	67,721	8,401	497	1,656	8,715
Additions for tax positions of prior years	429,232	392,548	331,432	4,057	445	4,834	271,172
Reductions for tax positions of prior years	(39,534)	(50,518)	(169,465)	(5,703)	(2,506)	(11,649)	(20,934)
Settlements	(390,931)	(275,776)	(139,202)	(966)	(2,470)	(112)	(279,790)
Gross balance at December 31, 2012	344,669	465,721	536,673	16,841	52,018	13,954	260,346
Offsets to gross							

unrecognized tax benefits:							
Loss carryovers	(342,127)	(160,955)	(536,673)	(16,841)	(35,511)	(1,593)	(249,424)
Unrecognized tax benefits net of unused tax attributes and payments	$2,542	$304,766	$—	$—	$16,507	$12,361	$ 10,922

2011	Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
				(In Thousands)			
Gross balance at January 1, 2011	$240,239	$353,886	$505,188	$24,163	$18,176	$14,229	$224,518
Additions based on tax positions related to the current year	11,216	9,398	8,748	457	50,212	1,760	44,419
Additions for tax positions of prior years	44,202	50,944	21,052	21,902	7,343	7,533	14,200
Reductions for tax positions of prior years	(3,255)	(21,719)	(27,991)	(5,022)	(12,289)	(3,432)	(4,942)
Settlements	43,091	(2,016)	(60,810)	(30,448)	(7,390)	(865)	2,988
Gross balance at December 31, 2011	335,493	390,493	446,187	11,052	56,052	19,225	281,183
Offsets to gross unrecognized tax benefits:							
Loss carryovers	(146,429)	(26,394)	(216,720)	(5,930)	(1,211)	(10,645)	(10,752)
Cash paid to taxing authorities	(75,977)	(45,493)	—	(7,556)	(1,174)	(1,376)	(41,878)
Unrecognized tax benefits net of used tax attributes and payments	$113,087	$318,606	$229,467	($2,434)	$53,667	$7,204	$228,553

The Registrant Subsidiaries’ balances of unrecognized tax benefits included amounts which, if recognized, would have reduced income tax expense as follows:

	December 31, 2013	December 31, 2012	December 31, 2011
		(In Millions)	

Entergy Arkansas	$0.6	$0.6	$—
Entergy Gulf States Louisiana	$44.0	$44.0	$107.9
Entergy Louisiana	$87.9	$92.4	$281.3
Entergy Mississippi	$3.9	$3.9	$3.8
Entergy New Orleans	$—	$—	$—
Entergy Texas	$10.1	$8.6	$7.3
System Energy	$3.3	$3.5	$—

The Registrant Subsidiaries accrue interest and penalties related to unrecognized tax benefits in income tax expense. Penalties have not been accrued. Accrued balances for the possible payment of interest are as follows:

	December 31, 2013	December 31, 2012	December 31, 2011
		(In Millions)	
Entergy Arkansas	$15.2	$21.8	$11.4
Entergy Gulf States Louisiana	$17.0	$33.1	$14.4
Entergy Louisiana	$1.0	$0.9	$0.8
Entergy Mississippi	$2.1	$2.4	$1.7
Entergy New Orleans	$0.9	$0.1	$2.4
Entergy Texas	$0.8	$0.7	$0.1
System Energy	$19.0	$33.2	$18.5

Income Tax Litigation

2000 Tax Year

In February 2008 the IRS issued a Statutory Notice of Deficiency for the year 2000. The deficiency resulted from a disallowance of foreign tax credits (the same issue discussed above) as well as the disallowance of depreciation deductions on non-utility nuclear plants. Entergy filed a Tax Court petition in May 2008 challenging the IRS treatment of these issues. In June 2010 a trial on the depreciation issue was held in Washington, D.C. In February 2011 a joint stipulation of settled issues was filed under which the IRS conceded its position with respect to the depreciation issue. The outcome of the foreign tax credit matter for the year 2000 is effectively settled in Entergy's favor as determined by the U.S. Supreme Court's unanimous decision in the PPL proceeding in May 2013 as discussed above.

Income Tax Audits

Entergy and its subsidiaries file U.S. federal and various state and foreign income tax returns. IRS examinations are substantially completed for years before 2009. All state taxing authorities' examinations are completed for years before 2005.

2004-2005 IRS Audit

In June 2009, Entergy filed a formal protest with the IRS Appeals Division indicating disagreement with certain issues contained in the 2004-2005 Revenue Agent's Report (RAR). The most significant issue disputed was the inclusion of nuclear decommissioning liabilities in cost of goods sold for the nuclear power plants owned by the Utility resulting from an Application for Change in Accounting Method for tax purposes (the "2004 CAM").

During the fourth quarter 2012, Entergy settled the position relating to the 2004 CAM. Under the settlement Entergy conceded its tax position, resulting in an increase in taxable income of approximately $2.97 billion for the tax years 2004 - 2007. The settlement provides that Entergy Louisiana is entitled to additional tax depreciation of approximately $547 million for years 2006 and beyond. The deferred tax asset net of interest charges associated with the settlement is $155 million for Entergy. There was a related increase to Entergy Louisiana's member's equity account.

2006-2007 IRS Audit

The IRS issued its 2006-2007 RAR in October 2011. In connection with the 2006-2007 IRS audit and resulting RAR, Entergy resolved the significant issues discussed below.

In August 2011, Entergy entered into a settlement agreement with the IRS relating to the mark-to-market income tax treatment of various wholesale electric power purchase and sale agreements, including Entergy Louisiana's contract to purchase electricity from the Vidalia hydroelectric facility. See Note 8 to the financial statements for further details regarding this contract and a previous LPSC-approved settlement regarding the tax treatment of the contract.

With respect to income tax accounting for wholesale electric power purchase agreements, Entergy recognized income for tax purposes of approximately $1.5 billion, which represents a reversal of previously deducted temporary differences on which deferred taxes had been provided. Also in connection with this settlement, Entergy recognized a gain for income tax purposes of approximately $1.03 billion on the formation of a wholly-owned subsidiary in 2005 with a corresponding step-up in the tax basis of depreciable assets resulting in additional tax depreciation at Entergy Louisiana. Because Entergy Louisiana is entitled to deduct additional tax depreciation of $1.03 billion in the future, Entergy Louisiana recorded a deferred tax asset for this additional tax basis. The tax expense associated with the gain is offset by recording the deferred tax asset and by utilization of net operating losses. With the recording of the deferred tax asset, there was a corresponding increase to Entergy Louisiana's member's equity account. The agreement with the IRS effectively settled the tax treatment of various wholesale electric power purchase and sale agreements, resulting in the reversal in third quarter 2011 of approximately $422 million of deferred tax liabilities and liabilities for uncertain tax positions at Entergy Louisiana, with a corresponding reduction in income tax expense. Under the terms of an LPSC-approved final settlement, Entergy Louisiana recorded a $199 million regulatory charge and a corresponding regulatory liability.

After consideration of the taxable income recognition and the additional depreciation deductions provided for in the settlement, Entergy's net operating loss carryover was reduced by approximately $2.5 billion.

2008-2009 IRS Audit

In the third quarter 2008, Entergy Louisiana and Entergy Gulf States Louisiana received $679 million and $274.7 million, respectively, from the Louisiana Utilities Restoration Corporation ("LURC"). These receipts from LURC were from the proceeds of a Louisiana Act 55 financing of the costs incurred to restore service following Hurricane Katrina and Hurricane Rita. See Note 2 to the financial statements for further details regarding the financings.

In June 2012, Entergy effectively settled the tax treatment of the storm restoration, which resulted in an increase to 2008 taxable income of $129 million for Entergy Louisiana and $104 million for Entergy Gulf States Louisiana and a reduction of income tax expense of $172 million, including $143 million for Entergy Louisiana and $20 million for Entergy Gulf States Louisiana. Under the terms of an LPSC-approved settlement related to the Louisiana Act 55 financings, Entergy Louisiana and Entergy Gulf States Louisiana recorded, respectively, a $137 million ($84 million net-of-tax) and a $28 million ($17 million net-of-tax) regulatory charge and a corresponding regulatory liability to reflect their obligations to customers with respect to the settlement.

In the fourth quarter 2009, Entergy filed Applications for Change in Accounting Method (the "2009 CAM") for tax purposes with the IRS for certain costs under Section 263A of the Internal Revenue Code. In the Applications, Entergy proposed to treat the nuclear decommissioning liability associated with the operation of its nuclear power plants as a production cost properly includable in cost of goods sold. The effect of the 2009 CAM was a $5.7 billion reduction in 2009 taxable income. The 2009 CAM was adjusted to $9.3 billion in 2012.

In the fourth quarter 2012 the IRS disallowed the reduction to 2009 taxable income related to the 2009 CAM. In the third quarter 2013, the Internal Revenue Service issued its RAR for the tax years 2008-2009. As a result of the issuance of this RAR, Entergy and the IRS resolved all of the 2008-2009 issues described above except for the 2009 CAM. Entergy disagrees with the IRS's disallowance of the 2009 CAM and filed a protest with the IRS Appeals Division on October 24, 2013. The issuance of the RAR by the IRS effectively settles all other issues, which resulted in an adjustment to the provision for uncertain tax positions.

Other Tax Matters

Entergy regularly negotiates with the IRS to achieve settlements. The results of all pending litigations and audit issues could result in significant changes to the amounts of unrecognized tax benefits, as discussed above.

In March 2010, Entergy filed an Application for Change in Accounting Method with the IRS. In the application, Entergy proposed to change the definition of unit of property for its generation assets to determine the appropriate characterization of costs associated with such units as capital or repair under the Internal Revenue Code and related Treasury Regulations. The effect of this change was an approximate $1.3 billion reduction in 2011 taxable income for Entergy, including reductions of $292 million for Entergy Arkansas, $132 million for Entergy Gulf States Louisiana, $185 million for Entergy Louisiana, $48 million for Entergy Mississippi, $45 million for Entergy Texas, $13 million for Entergy New Orleans, and $180 million for System Energy.

In September 2013 the IRS issued final regulations that provide guidance on the deductibility and capitalization of costs incurred associated with tangible property. Although Entergy continues to analyze these regulations, which contain numerous complex provisions, Entergy currently estimates that the effect of the regulations would result in a $348 million reduction of Entergy's 2014 repairs and maintenance tax deduction, including decreases in the deduction of $114 million for Entergy Arkansas, $34 million for Entergy Gulf States Louisiana, $22 million for Entergy Louisiana, $43 million for Entergy Mississippi, $137 million for Entergy Texas, and an increase of $2 million for Entergy New Orleans.

During the second quarter 2011, Entergy filed an Application for Change in Accounting Method with the IRS related to the allocation of overhead costs between production and non-production activities. The accounting method affects the amount of overhead that will be capitalized or deducted for tax purposes. The accounting method is expected to be implemented for the 2014 tax year.

In March 2013, Entergy Louisiana distributed to its parent, Entergy Louisiana Holdings, Inc., Louisiana income tax credits of $20.6 million which resulted in a decrease in Entergy Louisiana's member's equity account.

NOTE 4. REVOLVING CREDIT FACILITIES, LINES OF CREDIT, AND SHORT-TERM BORROWINGS

Entergy Arkansas, Entergy Gulf States Louisiana, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, and Entergy Texas each had credit facilities available as of December 31, 2013 as follows:

Company	Expiration Date	Amount of Facility	Interest Rate (a)	Amount Drawn as of December 31, 2013
Entergy Arkansas	April 2014	$20 million (b)	1.75%	—
Entergy Arkansas	March 2018	$150 million (c)	1.67%	—
Entergy Gulf States Louisiana	March 2018	$150 million (d)	1.67%	—
Entergy Louisiana	March 2018	$200 million (e)	1.67%	—
Entergy Mississippi	May 2014	$35 million (f)	1.92%	—
Entergy Mississippi	May 2014	$20 million (f)	1.92%	—
Entergy Mississippi	May 2014	$37.5 million (f)	1.92%	—
Entergy New Orleans	November 2014	$25 million (g)	1.64%	—
Entergy Texas	March 2018	$150 million (h)	1.92%	—

(a) The interest rate is the rate as of December 31, 2013 that would be applied to outstanding borrowings under the facility.

(b) The credit facility requires Entergy Arkansas to maintain a debt ratio of 65% or less of its total capitalization. Entergy Arkansas is in compliance with this covenant. Borrowings under this Entergy Arkansas credit facility may be secured by a security interest in its accounts receivable.

(c) The credit facility allows Entergy Arkansas to issue letters of credit against 50% of the borrowing capacity of the facility. As of December 31, 2013, $0.2 million in letters of credit were outstanding. The credit facility requires Entergy Arkansas to maintain a consolidated debt ratio of 65% or less of its total capitalization. Entergy Arkansas is in compliance with this covenant.

(d) The credit facility allows Entergy Gulf States Louisiana to issue letters of credit against 50% of the borrowing capacity of the facility. As of December 31, 2013, $15.2 million in letters of credit were outstanding. The credit facility requires Entergy Gulf States Louisiana to maintain a consolidated debt ratio of 65% or less of its total capitalization. Entergy Gulf States Louisiana is in compliance with this covenant.

(e) The credit facility allows Entergy Louisiana to issue letters of credit against 50% of the borrowing capacity of the facility. As of December 31, 2013, $7.0 million in letters of credit were outstanding. The credit facility requires Entergy Louisiana to maintain a consolidated debt ratio of 65% or less of its total capitalization. Entergy Louisiana is in compliance with this covenant.

(f) The credit facilities require Entergy Mississippi to maintain a debt ratio of 65% or less of its total capitalization. Entergy Mississippi is in compliance with this covenant. Borrowings under the Entergy Mississippi credit facilities may be secured by a security interest in its accounts receivable.

(g) The credit facility requires Entergy New Orleans to maintain a debt ratio of 65% or less of its total capitalization. Entergy New Orleans is in compliance with this covenant.

(h) The credit facility allows Entergy Texas to issue letters of credit against 50% of the borrowing capacity of the facility. As of December 31, 2013, $25 million in letters of credit were outstanding. The credit facility requires Entergy Texas to maintain a consolidated debt ratio of 65% or less of its total capitalization. Entergy Texas is in compliance with this covenant.

The facility fees on the credit facilities range from 0.125% to 0.275% of the commitment amount.

The short-term borrowings of the Registrant Subsidiaries are limited to amounts authorized by the FERC. The current FERC-authorized limits are effective through October 31, 2015. In addition to borrowings from commercial banks, these companies are authorized under a FERC order to borrow from the Entergy System money pool. The money pool is an inter-company borrowing arrangement designed to reduce the Utility subsidiaries' dependence on external short-term borrowings. Borrowings from the money pool and external borrowings combined may not exceed the FERC-authorized limits. The following are the FERC-authorized limits for short-term borrowings and the outstanding short-term borrowings as of December 31, 2013 (aggregating both money pool and external short-term borrowings) for the Registrant Subsidiaries:

	Authorized	Borrowings
	(In Millions)	
Entergy Arkansas	$250	—
Entergy Gulf States Louisiana	$200	—
Entergy Louisiana	$250	—
Entergy Mississippi	$175	$4
Entergy New Orleans	$100	—
Entergy Texas	$200	—
System Energy	$200	—

NOTE 5. LONG - TERM DEBT

Details of long-term debt are presented on FERC Form 1 pages 256-257.

Entergy Arkansas has obtained long-term financing authorization from the APSC that extends through December 2015.

NOTE 6. PREFERRED EQUITY

Details of preferred equity are presented on FERC Form 1 pages 250-251.

NOTE 7. COMMON EQUITY

Details of common equity are presented on FERC Form 1 pages 250-251.

Retained Earnings and Dividend Restrictions

Provisions within the articles of incorporation or pertinent indentures and various other agreements relating to the long-term debt and preferred stock of certain of Entergy Corporation's subsidiaries could restrict the payment of cash dividends or other distributions on their common and preferred equity. As of December 31, 2013, under provisions in their mortgage indentures, Entergy Arkansas and Entergy Mississippi had retained earnings unavailable for distribution to Entergy Corporation of $394.9 million and $68.5 million, respectively. Entergy Corporation received dividend payments from subsidiaries totaling $702 million in 2013, $439 million in 2012, and $595 million in 2011.

NOTE 8. COMMITMENTS AND CONTINGENCIES

Entergy and the Registrant Subsidiaries are involved in a number of legal, regulatory, and tax proceedings before various courts, regulatory commissions, and governmental agencies in the ordinary course of business. While management is unable to predict the outcome of such proceedings, management does not believe that the ultimate resolution of these matters will have a material effect on Entergy's results of operations, cash flows, or financial condition. Entergy discusses regulatory proceedings in Note 2 to the financial statements and discusses tax proceedings in Note 3 to the financial statements.

ANO Damage and Outage

On March 31, 2013, during a scheduled refueling outage at ANO 1, a contractor-owned and operated heavy-lifting apparatus collapsed while moving the generator stator out of the turbine building. The collapse resulted in the death of an ironworker and injuries to several other contract workers, caused ANO 2 to shut down, and damaged the ANO turbine building. The turbine building serves both ANO 1 and 2 and is a non-radiological area of the plant. ANO 2 reconnected to the grid on April 28, 2013 and ANO 1 reconnected to the grid on August 7, 2013. The total cost of assessment, restoration of off-site power, site restoration, debris removal, and replacement of damaged property and equipment was $94 million as of December 31, 2013. In addition, Entergy Arkansas incurred replacement power costs for ANO 2 power during its outage and incurred incremental replacement power costs for ANO 1 power because the outage extended beyond the originally-planned duration of the refueling outage. Each of the Utility operating companies has recovery mechanisms in place designed to recover its prudently-incurred fuel and purchased power costs.

Entergy Arkansas is assessing its options for recovering damages that resulted from the stator drop, including its insurance coverage and legal action. Entergy is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurance company that provides property damage coverage to the members' nuclear generating plants, including ANO. NEIL has notified Entergy that it believes that a $50 million course of construction sublimit applies to any loss associated with the lifting apparatus failure and stator drop at ANO. Entergy has responded that it disagrees with NEIL's position and is evaluating its options for enforcing its rights under the policy. On July 12, 2013, Entergy Arkansas filed a complaint in the Circuit Court in Pope County, Arkansas against the owner of the heavy-lifting apparatus that collapsed, an engineering firm, a general contractor, and certain individuals asserting claims of breach of contract, negligence, and gross negligence in connection with their responsibility for the stator drop.

In the second quarter 2013, Entergy Arkansas recorded an insurance receivable of $50 million based on the minimum amount that it expects to receive from NEIL. This $50 million receivable offset approximately $35 million of capital spending, $13 million of operation and maintenance expense, and $2 million of incremental deferred refueling outage costs incurred for the recovery through December 31, 2013. As of December 31, 2013, Entergy Arkansas has incurred approximately $34 million in capital spending, $9 million in operation and maintenance expense, and $1 million in incremental deferred refueling outage costs in excess of its recorded insurance receivable. In January 2014, Entergy Arkansas collected $20 million of the $50 million receivable that it expects to receive from NEIL.

Nuclear Insurance

Third Party Liability Insurance

The Price-Anderson Act requires that reactor licensees purchase insurance and participate in a secondary insurance pool that provides insurance coverage for the public in the event of a nuclear power plant accident. The costs of this insurance are borne by the nuclear power industry. Congress amended and renewed the Price-Anderson Act in 2005 for a term through 2025. The Price-Anderson Act requires nuclear power plants to show evidence of financial protection in the event of a nuclear accident. This protection must consist of two layers of coverage:

1. The primary level is private insurance underwritten by American Nuclear Insurers (ANI) and provides public liability insurance coverage of $375 million. If this amount is not sufficient to cover claims arising from an accident, the second level, Secondary Financial Protection, applies.
2. Within the Secondary Financial Protection level, each nuclear reactor has a contingent obligation to pay a retrospective premium, equal to its proportionate share of the loss in excess of the primary level, regardless of proximity to the incident or fault, up to a maximum of $127.3 million per reactor per incident (Entergy's

maximum total contingent obligation per incident is $1.4 billion). This consists of a $121.3 million maximum retrospective premium plus a five percent surcharge, which equates to $127.3 million, that may be payable, if needed, at a rate that is currently set at $19.0 million per year per incident per nuclear power reactor.

3. In the event that one or more acts of terrorism cause a nuclear power plant accident, which results in third-party damages – off-site property and environmental damage, off-site bodily injury, and on-site third-party bodily injury (i.e. contractors); the primary level provided by ANI combined with the Secondary Financial Protection would provide $13.6 billion in coverage. The Terrorism Risk Insurance Reauthorization Act of 2007 created a government program that provides for up to $100 billion in coverage in excess of existing coverage for a terrorist event.

Currently, 104 nuclear reactors are participating in the Secondary Financial Protection program. The product of the maximum retrospective premium assessment to the nuclear power industry and the number of nuclear power reactors provides over $13.2 billion in secondary layer insurance coverage to compensate the public in the event of a nuclear power reactor accident. The Price-Anderson Act provides that all potential liability for a nuclear accident is limited to the amounts of insurance coverage available under the primary and secondary layers.

Entergy Arkansas has two licensed reactors and Entergy Gulf States Louisiana, Entergy Louisiana, and System Energy each have one licensed reactor (10% of Grand Gulf is owned by a non-affiliated company (SMEPA) that would share on a pro-rata basis in any retrospective premium assessment to System Energy under the Price-Anderson Act).

Property Insurance

Entergy's nuclear owner/licensee subsidiaries are members of Nuclear Electric Insurance Limited (NEIL), a mutual insurance company that provides property damage coverage, including decontamination and premature decommissioning expense, to the members' nuclear generating plants. Effective April 1, 2013, Entergy was insured against such losses per the following structures:

<u>Utility Plants (ANO 1 and 2, Grand Gulf, River Bend, and Waterford 3)</u>

- Primary Layer (per plant) - $500 million per occurrence
- Excess Layer (per plant) - $750 million per occurrence
- Blanket Layer (shared among the Utility plants) - $350 million per occurrence
- Total limit - $1.6 billion per occurrence
- Deductibles:
    - $2.5 million per occurrence - Turbine/generator damage
    - $2.5 million per occurrence - Other than turbine/generator damage
    - $10 million per occurrence plus 10% of amount above $10 million - Damage from a windstorm, flood, earthquake, or volcanic eruption

Note: ANO 1 and 2 share in the primary and excess layers with common policies because the policies are issued on a per site basis. Also, flood and earthquake coverage are excluded from the primary layer, which provides the first

$500 million in coverage. Entergy currently purchases primary layer flood coverage for Waterford 3 and River Bend.

Under the property damage and accidental outage insurance programs, all NEIL insured plants could be subject to assessments should losses exceed the accumulated funds available from NEIL. Effective April 1, 2013, the maximum amounts of such possible assessments per occurrence were as follows:

	Assessments (In Millions)
Utility:	
Entergy Arkansas	$25.1
Entergy Gulf States Louisiana	$23
Entergy Louisiana	$24.2
Entergy Mississippi	$0.07
Entergy New Orleans	$0.07
Entergy Texas	N/A
System Energy	$18.9

Entergy maintains property insurance for its nuclear units in excess of the NRC's minimum requirement of $1.06 billion per site for nuclear power plant licensees. NRC regulations provide that the proceeds of this insurance must be used, first, to render the reactor safe and stable, and second, to complete decontamination operations. Only after proceeds are dedicated for such use and regulatory approval is secured would any remaining proceeds be made available for the benefit of plant owners or their creditors.

In the event that one or more acts of terrorism causes property damage under one or more or all nuclear insurance policies issued by NEIL (including, but not limited to, those described above) within 12 months from the date the first property damage occurs, the maximum recovery under all such nuclear insurance policies shall be an aggregate of $3.24 billion plus the additional amounts recovered for such losses from reinsurance, indemnity, and any other sources applicable to such losses. The Terrorism Risk Insurance Reauthorization Act of 2007 created a government program that provides for up to $100 billion in coverage in excess of existing coverage for a terrorist event.

Conventional Property Insurance

Entergy's conventional property insurance program provides coverage of up to $400 million on an Entergy system-wide basis for all operational perils (direct physical loss or damage due to machinery breakdown, electrical failure, fire, lightning, hail, or explosion) on an "each and every loss" basis; up to $400 million in coverage for certain natural perils (direct physical loss or damage due to earthquake, tsunami, and flood) on an annual aggregate basis; up to $125 million for certain other natural perils (direct physical loss or damage due to a named windstorm and associated storm surge) on an annual aggregate basis; and up to $400 million in coverage for all other natural perils not previously stated (direct physical loss or damage due to a tornado, ice storm, or any other natural peril except named windstorm and associated storm surge, earthquake, tsunami, and flood) on an "each and every loss" basis. The conventional property insurance program provides up to $50 million in coverage for the Entergy New Orleans gas distribution system on an "each and every loss" basis. This $50 million limit is subject to: the $400 million annual aggregate limit for the natural perils of earthquake, tsunami, and flood; the $125 million annual aggregate limit for the natural perils of named windstorm and associated storm surge; the $400 million per occurrence limit for all other natural perils not previously stated, which includes tornado and ice storm, but excludes named windstorm and associated storm surge, earthquake, tsunami, and flood; and the $400 million per occurrence limit for operational perils. The coverage is subject to a $40 million self-insured retention per occurrence for the natural perils of named windstorm and associated storm surge, earthquake, flood, and tsunami; and a $20 million self-insured retention per occurrence for operational perils and all other natural perils not previously stated, which includes tornado and ice storm, but excludes named windstorm and associated storm surge, earthquake, tsunami, and flood.

Covered property generally includes power plants, substations, facilities, inventories, and gas distribution-related properties. Excluded property generally includes above-ground transmission and distribution lines, poles, and towers for substations valued at $5 million or less, coverage for named windstorm and associated storm surge is excluded. This coverage is in place for Entergy Corporation, the Registrant Subsidiaries, and certain other Entergy subsidiaries, including the owners of the nuclear power plants in the Entergy Wholesale Commodities segment. Entergy also purchases $300 million in terrorism insurance coverage for its conventional property. The Terrorism Risk Insurance Reauthorization Act of 2007 created a government program that provides for up to $100 billion in coverage in excess of existing coverage for a terrorist event.

In addition to the conventional property insurance program, Entergy has purchased additional coverage ($20 million per occurrence) for some of its non-regulated, non-generation assets. This policy serves to buy-down the $20 million deductible and is placed on a scheduled location basis. The applicable deductibles are $100,000 to $250,000, except for properties that are damaged by flooding and properties whose values are greater than $20 million; these properties have a $500,000 deductible. Four nuclear locations have a $2.5 million deductible, which coincides with the nuclear property insurance deductible at each respective nuclear site.

Employment and Labor-related Proceedings

The Registrant Subsidiaries and other Entergy subsidiaries are responding to various lawsuits in both state and federal courts and to other labor-related proceedings filed by current and former employees, recognized bargaining representatives, and third parties not selected for open positions or providing services directly or indirectly to one or more of the Registrant Subsidiaries and other Entergy subsidiaries. Generally, the amount of damages being sought is not specified in these proceedings. These actions include, but are not limited to, allegations of wrongful employment actions; wage disputes and other claims under the Fair Labor Standards Act or its state counterparts; claims of race, gender, age, and disability discrimination; disputes arising under collective bargaining agreements; unfair labor practice proceedings and other administrative proceedings before the National Labor Relations Board or concerning the National Labor Relations Act; claims of retaliation; claims of harassment and hostile work environment; and claims for or regarding benefits under various Entergy Corporation-sponsored plans. Entergy and the Registrant Subsidiaries are responding to these lawsuits and proceedings and deny liability to the claimants. Management believes that loss exposure has been and will continue to be handled so that the ultimate resolution of these matters will not be material, in the aggregate, to the financial position, results of operation, or cash flows of Entergy or the Utility operating companies.

Grand Gulf - Related Agreements

Capital Funds Agreement (Entergy Corporation and System Energy)

System Energy has entered into agreements with Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans whereby they are obligated to purchase their respective entitlements of capacity and energy from System Energy's interest in Grand Gulf, and to make payments that, together with other available funds, are adequate to cover System Energy's operating expenses. System Energy would have to secure funds from other sources, including Entergy Corporation's obligations under the Capital Funds Agreement, to cover any shortfalls from payments received from Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans under these agreements.

Unit Power Sales Agreement (Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, and System Energy)

System Energy has agreed to sell all of its share of capacity and energy from Grand Gulf to Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans in accordance with specified percentages (Entergy Arkansas-36%, Entergy Louisiana-14%, Entergy Mississippi-33%, and Entergy New Orleans-17%) as ordered by the FERC. Charges under this agreement are paid in consideration for the purchasing companies' respective entitlement to receive capacity and energy and are payable irrespective of the quantity of energy delivered. The agreement will remain in effect until terminated by the parties and the termination is approved by the FERC, most likely upon Grand Gulf's retirement from service. Monthly obligations are based on actual capacity and energy costs. The average monthly payments for 2013 under the agreement are approximately $22.3 million for Entergy Arkansas, $8.7 million for Entergy Louisiana, $19.2 million for Entergy Mississippi, and $10.8 million for Entergy New Orleans.

Availability Agreement (Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, and System Energy)

Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans are individually obligated to make payments or subordinated advances to System Energy in accordance with stated percentages (Entergy Arkansas-17.1%, Entergy Louisiana-26.9%, Entergy Mississippi-31.3%, and Entergy New Orleans-24.7%) in amounts that, when added to amounts received under the Unit Power Sales Agreement or otherwise, are adequate to cover all of System Energy's operating expenses as defined, including an amount sufficient to amortize the cost of Grand Gulf 2 over 27 years (See Reallocation Agreement terms below) and expenses incurred in connection with a permanent shutdown of Grand Gulf. System Energy has assigned its rights to payments and advances to certain creditors as security for certain obligations. Since commercial operation of Grand Gulf began, payments under the Unit Power Sales Agreement have exceeded the amounts payable under the Availability Agreement. Accordingly, no payments under the Availability Agreement have ever been required. If Entergy Arkansas or Entergy Mississippi fails to make its Unit Power Sales Agreement payments, and System Energy is unable to obtain funds from other sources, Entergy Louisiana and Entergy

New Orleans could become subject to claims or demands by System Energy or its creditors for payments or advances under the Availability Agreement (or the assignments thereof) equal to the difference between their required Unit Power Sales Agreement payments and their required Availability Agreement payments.

Reallocation Agreement (Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, and System Energy)

System Energy, Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans entered into the Reallocation Agreement relating to the sale of capacity and energy from Grand Gulf and the related costs, in which Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans agreed to assume all of Entergy Arkansas's responsibilities and obligations with respect to Grand Gulf under the Availability Agreement. FERC's decision allocating a portion of Grand Gulf capacity and energy to Entergy Arkansas supersedes the Reallocation Agreement as it relates to Grand Gulf. Responsibility for any Grand Gulf 2 amortization amounts has been individually allocated (Entergy Louisiana-26.23%, Entergy Mississippi-43.97%, and Entergy New Orleans-29.80%) under the terms of the Reallocation Agreement. However, the Reallocation Agreement does not affect Entergy Arkansas's obligation to System Energy's lenders under the assignments referred to in the preceding paragraph. Entergy Arkansas would be liable for its share of such amounts if Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans were unable to meet their contractual obligations. No payments of any amortization amounts will be required so long as amounts paid to System Energy under the Unit Power Sales Agreement, including other funds available to System Energy, exceed amounts required under the Availability Agreement, which is expected to be the case for the foreseeable future.

NOTE 9. ASSET RETIREMENT OBLIGATIONS

Accounting standards require companies to record liabilities for all legal obligations associated with the retirement of long-lived assets that result from the normal operation of the assets. For Entergy, substantially all of its asset retirement obligations consist of its liability for decommissioning its nuclear power plants. In addition, an insignificant amount of removal costs associated with non-nuclear power plants is also included in the decommissioning line item on the balance sheets.

These liabilities are recorded at their fair values (which are the present values of the estimated future cash outflows) in the period in which they are incurred, with an accompanying addition to the recorded cost of the long-lived asset. The asset retirement obligation is accreted each year through a charge to expense, to reflect the time value of money for this present value obligation. The accretion will continue through the completion of the asset retirement activity. The amounts added to the carrying amounts of the long-lived assets will be depreciated over the useful lives of the assets. The application of accounting standards related to asset retirement obligations is earnings neutral to the rate-regulated business of the Registrant Subsidiaries.

In accordance with ratemaking treatment and as required by regulatory accounting standards, the depreciation provisions for the Registrant Subsidiaries include a component for removal costs that are not asset retirement obligations under accounting standards. In accordance with regulatory accounting principles, the Registrant Subsidiaries have recorded regulatory assets (liabilities) in the following amounts to reflect their estimates of the difference between estimated incurred removal costs and estimated removal costs recovered in rates:

	December 31, 2013	December 31, 2012
	(In Millions)	
Entergy Arkansas	$18.6	($12.2)
Entergy Gulf States Louisiana	($35.3)	($22.0)
Entergy Louisiana	($37.0)	($9.2)
Entergy Mississippi	$64.3	$57.4
Entergy New Orleans	$34.9	$29.9
Entergy Texas	$15.1	$11.5
System Energy	$56.0	$56.8

The cumulative decommissioning and retirement cost liabilities and expenses recorded in 2013 by Entergy were as follows:

	Liabilities as of December 31, 2012	Accretion	Change in Cash Flow Estimate	Spending	Liabilities as of December 31, 2013
			(In Millions)		
Utility:					
Entergy Arkansas	$680.7	$43.1	$—	$—	$723.8
Entergy Gulf States Louisiana	$380.8	$22.3	$—	$—	$403.1
Entergy Louisiana	$418.1	$21.6	$39.4	$—	$479.1
Entergy Mississippi	$6.0	$0.4	$—	$—	$6.4
Entergy New Orleans	$2.2	$0.1	$—	$—	$2.3
Entergy Texas	$4.1	$0.2	$—	$—	$4.3
System Energy	$478.4	$35.5	$102.3	$—	$616.2

The cumulative decommissioning and retirement cost liabilities and expenses recorded in 2012 by Entergy were as follows:

	Liabilities as of December 31, 2011	Accretion	Change in Cash Flow Estimate	Spending	Liabilities as of December 31, 2012
			(In Millions)		
Utility:					
Entergy Arkansas	$640.2	$40.5	$—	$—	$680.7
Entergy Gulf States Louisiana	$359.8	$21.0	$—	$—	$380.8
Entergy Louisiana	$345.8	$23.4	$48.9	$—	$418.1
Entergy Mississippi	$5.7	$0.3	$—	$—	$6.0
Entergy New Orleans	$2.9	$0.2	$—	($0.9)	$2.2
Entergy Texas	$3.9	$0.2	$—	$—	$4.1

System Energy	$445.4	$33.0	$—	$—	$478.4

Entergy periodically reviews and updates estimated decommissioning costs. The actual decommissioning costs may vary from the estimates because of regulatory requirements, changes in technology, and increased costs of labor, materials, and equipment. As described below, during 2013 and 2012 Entergy updated decommissioning cost estimates for certain nuclear power plants.

Entergy maintains decommissioning trust funds that are committed to meeting its obligations for the costs of decommissioning the nuclear power plants. The fair values of the decommissioning trust funds and the related asset retirement obligation regulatory assets (liabilities) of Entergy as of December 31, 2013 are as follows:

	Decommissioning Trust Fair Values	**Regulatory Asset (Liability)**
	(In Millions)	
Utility:		
ANO 1 and ANO 2	$710.9	$219.1
River Bend	$573.7	($28.7)
Waterford 3	$347.3	$128.5
Grand Gulf	$603.9	$60.8

Entergy maintains decommissioning trust funds that are committed to meeting its obligations for the costs of decommissioning the nuclear power plants. The fair values of the decommissioning trust funds and the related asset retirement obligation regulatory assets (liabilities) of Entergy as of December 31, 2012 are as follows:

	Decommissioning Trust Fair Values	**Regulatory Asset (Liability)**
	(In Millions)	
Utility:		
ANO 1 and ANO 2	$600.6	$204.0
River Bend	$477.4	($1.7)
Waterford 3	$287.4	$126.7
Grand Gulf	$490.6	$58.9

NOTE 10. LEASES

General

As of December 31, 2013, the Registrant Subsidiaries had capital leases and non-cancelable operating leases for equipment, buildings, vehicles, and fuel storage facilities (excluding nuclear fuel leases and the sale and leaseback transactions) with minimum lease payments as follows:

Capital Leases

Year	Entergy Arkansas	Entergy Mississippi
	(In Thousands)	
2014	$237	$1,570
2015	158	1,570
2016	—	1,570
2017	—	1,570
2018	—	785
Years thereafter	—	—
Minimum lease payments	395	7,065
Less: Amount representing interest	216	1,081
Present value of net minimum lease payments	$179	$5,984

Operating Leases

Year	Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
			(In Thousands)			
2014	$32,124	$19,735	$11,398	$7,155	$2,121	$6,442
2015	33,069	10,294	9,825	6,162	2,083	5,620
2016	17,999	9,551	6,574	4,379	1,720	4,487
2017	11,019	8,547	4,580	2,992	1,300	3,318
2018	6,669	7,753	3,078	2,300	883	2,681
Years thereafter	3,908	34,981	3,706	4,306	1,988	2,356
Minimum lease payments	$104,788	$90,861	$39,161	$27,294	$10,095	$24,904

Rental Expenses

Year	Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
				(In Millions)			
2013	$12.0	$10.9	$10.1	$4.6	$1.3	$4.1	$2.5
2012	$12.6	$11.9	$11.2	$5.5	$1.5	$6.4	$1.5
2011	$13.4	$12.2	$12.2	$5.2	$1.7	$8.4	$1.6

In addition to the above rental expense, railcar operating lease payments and oil tank facilities lease payments are recorded in fuel expense in accordance with regulatory treatment. Railcar operating lease payments were $8.6 million in 2013, $8.5 million in 2012, and $8.3 million in 2011 for Entergy Arkansas and $2.2 million in 2013, $1.7 million in 2012, and $2.0 million in 2011 for Entergy Gulf States Louisiana. Oil tank facilities lease payments for Entergy Mississippi were $3.4 million in 2013, $3.4 million in 2012, and $3.4 million in 2011.

NOTE 11. RETIREMENT, OTHER POSTRETIREMENT BENEFITS, AND DEFINED CONTRIBUTION PLANS

Qualified Pension Plans

Entergy has seven qualified pension plans covering substantially all employees: "Entergy Corporation Retirement Plan for Non-Bargaining Employees," "Entergy Corporation Retirement Plan for Bargaining Employees," "Entergy Corporation Retirement Plan II for Non-Bargaining Employees," "Entergy Corporation Retirement Plan II for Bargaining Employees," "Entergy Corporation Retirement Plan III," "Entergy Corporation Retirement Plan IV for Non-Bargaining Employees," and "Entergy Corporation Retirement Plan IV for Bargaining Employees." The Registrant Subsidiaries participate in two of these plans: "Entergy Corporation Retirement Plan for Non-Bargaining Employees" and "Entergy Corporation Retirement Plan for Bargaining Employees." Except for the Entergy Corporation Retirement Plan III, the pension plans are noncontributory and provide pension benefits that are based on employees' credited service and compensation during the final years before retirement. The Entergy Corporation Retirement Plan III includes a mandatory employee contribution of 3% of earnings during the first 10 years of plan participation, and allows voluntary contributions from 1% to 10% of earnings for a limited group of employees.

The assets of the seven qualified pension plans are held in a master trust established by Entergy. Each pension plan has an undivided beneficial interest in each of the investment accounts of the master trust that is maintained by a trustee. Use of the master trust permits the commingling of the trust assets of the pension plans of Entergy Corporation and its Registrant Subsidiaries for investment and administrative purposes. Although assets are commingled in the master trust, the trustee maintains supporting records for the purpose of allocating the equity in net earnings (loss) and the administrative expenses of the investment accounts to the various participating pension plans. The fair value of the trust assets is determined by the trustee and certain investment managers. The trustee calculates a daily earnings factor, including realized and unrealized gains or losses, collected and accrued income, and administrative expenses, and allocates earnings to each plan in the master trust on a pro rata basis.

Further, within each pension plan, the record of each Registrant Subsidiary's beneficial interest in the plan assets is maintained by the plan's actuary and is updated quarterly. Assets for each Registrant Subsidiary are increased for investment income and contributions, and decreased for benefit payments. A plan's investment net income/(loss) (i.e. interest and dividends, realized gains and losses and expenses) is allocated to the Registrant Subsidiaries participating in that plan based on the value of assets for each Registrant Subsidiary at the beginning of the quarter adjusted for contributions and benefit payments made during the quarter.

Entergy Corporation and its subsidiaries fund pension costs in accordance with contribution guidelines established by the Employee Retirement Income Security Act of 1974, as amended, and the Internal Revenue Code of 1986, as amended. The assets of the plans include common and preferred stocks, fixed-income securities, interest in a money market fund, and insurance contracts. The Registrant Subsidiaries' pension costs are recovered from customers as a component of cost of service in each of their respective jurisdictions.

Components of Qualified Net Pension Cost and Other Amounts Recognized as a Regulatory Asset and/or Accumulated Other Comprehensive Income (AOCI)

The Registrant Subsidiaries' total 2013, 2012, and 2011 qualified pension costs and amounts recognized as a regulatory asset and/or other comprehensive income, including amounts capitalized, for their employees included the following components:

2013	Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
				(In Thousands)			
Net periodic pension cost:							
Service cost - benefits earned during the period	$25,229	$14,258	$17,044	$7,295	$3,264	$6,475	$7,242
Interest cost on projected benefit obligation	54,473	26,741	34,857	15,802	7,462	16,303	12,170
Expected return on assets	(66,951)	(34,982)	(41,948)	(21,139)	(9,117)	(22,277)	(17,249)
Amortization of prior service cost	23	9	83	10	2	6	9
Recognized net loss	49,517	23,374	34,107	13,189	7,878	13,302	9,560
Curtailment loss	4,938	805	3,542	767	343	1,559	—
Special termination benefit	1,784	808	1,631	359	581	855	1,970
Net pension cost	$69,013	$31,013	$49,316	$16,283	$10,413	$16,223	$13,702
Other changes in plan assets and benefit obligations recognized as a regulatory asset and/or AOCI (before tax)							
Arising this period:							
Net gain	($177,105)	($98,610)	($123,234)	($52,525)	($25,419)	($55,772)	($35,511)
Amounts reclassified from regulatory asset and/or AOCI to net periodic pension cost in the current year:							
Amortization of prior service cost	(23)	(9)	(83)	(10)	(2)	(6)	(9)
Amortization of net loss	(49,517)	(23,374)	(34,107)	(13,189)	(7,878)	(13,302)	(9,560)
Total	($226,645)	($121,993)	($157,424)	($65,724)	($33,299)	($69,080)	($45,080)
Total recognized as net periodic pension income							

regulatory asset, and/or AOCI (before tax)	($157,632)	($90,980)	($108,108)	($49,441)	($22,886)	($52,857)	($31,378)
Estimated amortization amounts from regulatory asset and/or AOCI to net periodic cost in the following year							
Prior service cost	$—	$—	$—	$—	$—	$—	$2
Net loss	$35,984	$15,935	$24,360	$9,421	$5,802	$9,363	$9,510

2012	**Entergy Arkansas**	**Entergy Gulf States Louisiana**	**Entergy Louisiana**	**Entergy Mississippi**	**Entergy New Orleans**	**Entergy Texas**	**System Energy**
				(In Thousands)			
Net periodic pension cost:							
Service cost - benefits earned during the period	$22,169	$12,273	$14,675	$6,410	$2,824	$5,684	$5,920
Interest cost on projected benefit obligation	55,686	25,679	35,201	16,279	7,608	16,823	12,987
Expected return on assets	(65,763)	(34,370)	(40,836)	(20,945)	(8,860)	(22,325)	(16,436)
Amortization of prior service cost	200	19	208	30	7	15	13
Recognized net loss	40,772	16,173	28,197	10,532	6,878	10,179	9,001
Net pension cost	$53,064	$19,774	$37,445	$12,306	$8,457	$10,376	$11,485
Other changes in plan assets and benefit obligations recognized as a regulatory asset and/or AOCI (before tax)							
Arising this period:							
Net loss	$105,133	$77,207	$76,163	$27,106	$14,282	$28,745	$10,266
Amounts reclassified from regulatory asset and/or AOCI to net periodic pension cost in the current year:							
Amortization of prior service cost	(200)	(19)	(208)	(30)	(7)	(15)	(13)
Amortization of net loss	(40,772)	(16,173)	(28,197)	(10,532)	(6,878)	(10,179)	(9,001)
Total	$64,161	$61,015	$47,758	$16,544	$7,397	$18,551	$1,252
Total recognized as net periodic pension cost, regulatory asset, and/or AOCI (before tax)	$117,225	$80,789	$85,203	$28,850	$15,854	$28,927	$12,737
Estimated amortization							

amounts from regulatory asset and/or AOCI to net periodic cost in the following year							
Prior service cost	$23	$9	$83	$10	$2	$6	$10
Net loss	$50,175	$23,731	$34,906	$13,375	$8,046	$13,494	$9,717

2011	**Entergy Arkansas**	**Entergy Gulf States Louisiana**	**Entergy Louisiana**	**Entergy Mississippi**	**Entergy New Orleans**	**Entergy Texas**	**System Energy**
				(In Thousands)			
Net periodic pension cost:							
Service cost - benefits earned during the period	$18,072	$9,848	$11,543	$5,308	$2,242	$4,788	$4,941
Interest cost on projected benefit obligation	51,965	23,713	32,636	15,637	7,050	15,971	11,758
Expected return on assets	(62,434)	(33,358)	(38,866)	(20,152)	(8,455)	(22,005)	(15,138)
Amortization of prior service cost	459	79	280	152	35	65	16
Recognized net loss	25,681	9,118	17,990	6,717	4,666	5,579	5,284
Net pension cost	$33,743	$9,400	$23,583	$7,662	$5,538	$4,398	$6,861
Other changes in plan assets and benefit obligations recognized as a regulatory asset and/or AOCI (before tax)							
Arising this period:							
Net loss	$217,989	$102,329	$137,100	$56,714	$29,297	$64,662	$52,876
Amounts reclassified from regulatory asset and/or AOCI to net periodic pension cost in the current year:							
Amortization of prior service cost	(459)	(79)	(280)	(152)	(35)	(65)	(16)
Amortization of net loss	(25,681)	(9,118)	(17,990)	(6,717)	(4,666)	(5,579)	(5,284)
Total	$191,849	$93,132	$118,830	$49,845	$24,596	$59,018	$47,576
Total recognized as net periodic pension cost, regulatory asset, and/or AOCI (before tax)	$225,592	$102,532	$142,413	$57,507	$30,134	$63,416	$54,437
Estimated amortization amounts from regulatory							

asset and/or AOCI to net periodic cost in the following year							
Prior service cost	$200	$19	$208	$30	$7	$15	$13
Net loss	$41,309	$16,295	$28,486	$10,667	$6,935	$10,261	$9,135

Qualified Pension Obligations, Plan Assets, Funded Status, and Amounts Recognized in the Balance Sheet for the Registrant Subsidiaries as of December 31, 2013 and 2012

2013	Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
				(In Thousands)			
Change in Projected Benefit Obligation (PBO)							
Balance at beginning of year	$1,274,886	$623,068	$817,745	$369,852	$174,585	$382,176	$282,841
Service cost	25,229	14,258	17,044	7,295	3,264	6,475	7,242
Interest cost	54,473	26,741	34,857	15,802	7,462	16,303	12,170
Curtailment	4,938	805	3,542	767	343	1,559	—
Special termination benefit	1,784	808	1,631	359	581	855	1,970
Actuarial gain	(110,943)	(64,119)	(80,794)	(31,684)	(16,276)	(33,792)	(23,882)
Benefits paid	(57,727)	(21,699)	(32,675)	(16,567)	(6,252)	(17,496)	(9,552)
Balance at end of year	$1,192,640	$579,862	$761,350	$345,824	$163,707	$356,080	$270,789
Change in Plan Assets							
Fair value of assets at beginning of year	$785,527	$409,971	$489,027	$248,272	$106,778	$262,110	$168,697
Actual return on plan assets	133,113	69,473	84,388	41,980	18,259	44,257	28,878
Employer contributions	35,382	11,550	21,152	8,152	4,175	6,880	8,305
Benefits paid	(57,727)	(21,699)	(32,675)	(16,567)	(6,252)	(17,496)	(9,552)
Fair value of assets at end of year	$896,295	$469,295	$561,892	$281,837	$122,960	$295,751	$196,328
Funded status	($296,345)	($110,567)	($199,458)	($63,987)	($40,747)	($60,329)	($74,461)
Amounts recognized in the balance sheet (funded status)							
Non-current liabilities	($296,345)	($110,567)	($199,458)	($63,987)	($40,747)	($60,329)	($74,461)
Amounts recognized as regulatory asset							
Prior service credit	$—	$—	($1)	$—	$—	$—	($4)
Net loss	457,485	178,990	299,740	120,290	69,856	120,619	121,327
	$ 457,485	$ 178,990	$ 299,739	$ 120,290	$ 69,856	$ 120,619	$ 121,323
Amounts recognized as AOCI (before tax)							
Net loss	—	25,437	—	—	—	—	—
	$—	$25,437	$—	$—	$—	$—	$—

2012	Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
				(In Thousands)			
Change in Projected Benefit Obligation (PBO)							
Balance at beginning of year	$1,116,572	$512,432	$704,748	$326,377	$151,966	$337,669	$258,268
Service cost	22,169	12,273	14,675	6,410	2,824	5,684	5,920
Interest cost	55,686	25,679	35,201	16,279	7,608	16,823	12,987
Actuarial loss	134,691	92,275	93,817	36,329	18,000	38,328	13,691
Benefits paid	(54,232)	(19,591)	(30,696)	(15,543)	(5,813)	(16,328)	(8,025)
Balance at end of year	$1,274,886	$623,068	$817,745	$369,852	$174,585	$382,176	$282,841
Change in Plan Assets							
Fair value of assets at beginning of year	$707,275	$366,555	$432,418	$223,981	$94,202	$237,438	$147,091
Actual return on plan assets	95,321	49,438	58,489	30,169	12,578	31,909	19,860
Employer contributions	37,163	13,569	28,816	9,665	5,811	9,091	9,771
Benefits paid	(54,232)	(19,591)	(30,696)	(15,543)	(5,813)	(16,328)	(8,025)
Fair value of assets at end of year	$785,527	$409,971	$489,027	$248,272	$106,778	$262,110	$168,697
Funded status	($489,359)	($213,097)	($328,718)	($121,580)	($67,807)	($120,066)	($114,144)
Amounts recognized in the balance sheet (funded status)							
Non-current liabilities	($489,359)	($213,097)	($328,718)	($121,580)	($67,807)	($120,066)	($114,144)
Amounts recognized as regulatory asset							
Prior service cost	$23	$8	$83	$10	$2	$7	$6
Net loss	683,790	283,847	456,800	185,903	103,072	189,589	166,276
	$683,813	$283,855	$456,883	$185,913	$103,074	$189,596	$166,282
Amounts recognized as AOCI (before tax)							
Prior service cost	$—	$1	$—	$—	$—	$—	$—
Net loss	—	42,414	—	—	—	—	—
	$—	$42,415	$—	$—	$—	$—	$—

Other Postretirement Benefits

Entergy also currently provides health care and life insurance benefits for retired employees. Substantially all employees may become eligible for these benefits if they reach retirement age and meet certain eligibility requirements while still working for Entergy. Entergy uses a December 31 measurement date for its postretirement benefit plans.

Effective January 1, 1993, Entergy adopted an accounting standard requiring a change from a cash method to an accrual method of accounting for postretirement benefits other than pensions. At January 1, 1993, the actuarially determined accumulated postretirement benefit obligation (APBO) earned by retirees and active employees was estimated to be approximately $241.4 million for Entergy (other than the former Entergy Gulf States) and $128 million for the former Entergy Gulf States (now split into Entergy Gulf States Louisiana and Entergy Texas). Such obligations were being amortized over a 20-year period that began in 1993 and ended in 2012. For the most part, the Registrant Subsidiaries recover accrued other postretirement benefit costs from customers and are required to contribute the other postretirement benefits collected in rates to an external trust.

Entergy Arkansas, Entergy Mississippi, Entergy New Orleans, and Entergy Texas have received regulatory approval to recover accrued other postretirement benefit costs through rates. Entergy Arkansas began recovery in 1998, pursuant to an APSC order. This order also allowed Entergy Arkansas to amortize a regulatory asset (representing the difference between other postretirement benefit costs and cash expenditures for other postretirement benefits incurred from 1993 through 1997) over a 15-year period that began in January 1998 and ended in December 2012.

Pursuant to regulatory directives, Entergy Arkansas, Entergy Mississippi, Entergy New Orleans, Entergy Texas, and System Energy contribute the other postretirement benefit costs collected in rates into external trusts. System Energy is funding, on behalf of Entergy Operations, other postretirement benefits associated with Grand Gulf.

Trust assets contributed by participating Registrant Subsidiaries are in bank-administered master trusts, established by Entergy Corporation and maintained by a trustee. Each participating Registrant Subsidiary holds a beneficial interest in the trusts' assets. The assets in the master trusts are commingled for investment and administrative purposes. Although assets are commingled, supporting records are maintained for the purpose of allocating the beneficial interest in net earnings/(losses) and the administrative expenses of the investment accounts to the various participating plans and participating Registrant Subsidiaries. Beneficial interest in an investment account's net income/(loss) is comprised of interest and dividends, realized and unrealized gains and losses, and expenses. Beneficial interest from these investments is allocated to the plans and participating Registrant Subsidiary based on their portion of net assets in the pooled accounts.

Other postretirement benefit changes

In December 2013, Entergy announced changes to its other postretirement benefits which include, among other things, elimination of other postretirement benefits for employees hired or rehired after June 30, 2014 and setting a dollar limit cap on Entergy's contribution to retiree medical costs, effective 2019 for those employees who commence their Entergy retirement benefits on or after January 1, 2015. In accordance with accounting standards, certain of the other postretirement benefit changes have been reflected in the December 31, 2013 other postretirement obligation. The changes affecting active bargaining unit employees will be negotiated with the unions prior to implementation, where necessary, and to the extent required by law.

Components of Net Other Postretirement Benefit Cost and Other Amounts Recognized as a Regulatory Asset and/or AOCI

Total 2013, 2012, and 2011 other postretirement benefit costs of the Registrant Subsidiaries, including amounts capitalized and deferred, for their employees included the following components:

2013	Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
				(In Thousands)			
Other postretirement costs:							
Service cost - benefits earned during the period	$9,619	$7,910	$8,541	$3,246	$1,752	$3,760	$3,580
Interest cost on APBO	13,545	8,964	9,410	4,289	3,135	6,076	2,945
Expected return on assets	(16,843)	—	—	(5,335)	(4,101)	(9,391)	(3,350)
Amortization of prior credit	(689)	(942)	(508)	(204)	(24)	(501)	(126)
Recognized net loss	7,976	4,598	5,050	2,534	1,509	3,744	1,896
Curtailment loss	4,517	1,546	1,848	596	354	1,436	760
Net other postretirement benefit cost	$18,125	$22,076	$24,341	$5,126	$2,625	$5,124	$5,705
Other changes in plan assets and benefit obligations recognized as a regulatory asset and/or AOCI (before tax)							
Arising this period:							
Prior service credit for the period	($11,617)	($8,705)	($18,844)	($4,714)	($4,469)	($5,359)	($4,591)
Net loss	($81,236)	($40,938)	($43,743)	($30,018)	($18,508)	($34,562)	($17,579)
Amounts reclassified from regulatory asset and/or AOCI to net periodic pension cost in the current year:							
Amortization of prior service credit	689	942	508	204	24	501	126
Acceleration of prior service credit/(cost) due to curtailment	78	91	41	20	(4)	62	9
Amortization of net loss	(7,976)	(4,598)	(5,050)	(2,534)	(1,509)	(3,744)	(1,896)
Total	($100,062)	($53,208)	($67,088)	($37,042)	($24,466)	($43,102)	($23,931)
Total recognized as net periodic other							

postretirement cost, regulatory asset, and/or AOCI (before tax)	($81,937)	($31,132)	($42,747)	($31,916)	($21,841)	($37,978)	($18,226)
Estimated amortization amounts from regulatory asset and/or AOCI to net periodic cost in the following year							
Prior service credit	($2,441)	($2,236)	($3,376)	($918)	($709)	($1,301)	($824)
Net loss	$1,267	$1,212	$1,511	$149	$56	$800	$464

2012	**Entergy Arkansas**	**Entergy Gulf States Louisiana**	**Entergy Louisiana**	**Entergy Mississippi**	**Entergy New Orleans**	**Entergy Texas**	**System Energy**
				(In Thousands)			
Other postretirement costs:							
Service cost - benefits earned during the period	$9,089	$7,521	$7,796	$3,093	$1,689	$3,651	$3,293
Interest cost on APBO	14,452	9,590	9,781	4,716	3,422	6,650	3,028
Expected return on assets	(14,029)	—	—	(4,521)	(3,711)	(8,415)	(2,601)
Amortization of transition obligation	820	238	382	351	1,189	187	8
Amortization of prior cost/(credit)	(530)	(824)	(247)	(139)	38	(428)	(63)
Recognized net loss	8,305	4,737	4,359	2,920	1,559	4,320	1,970
Net other postretirement benefit cost	$18,107	$21,262	$22,071	$6,420	$4,186	$5,965	$5,635
Other changes in plan assets and benefit obligations recognized as a regulatory asset and/or AOCI (before tax)							
Arising this period:							
Net loss	$9,066	$5,818	$16,215	$271	$2,260	$191	$2,043
Amounts reclassified from regulatory asset and/or AOCI to net periodic pension cost in the current year:							
Amortization of transition obligation	(820)	(238)	(382)	(351)	(1,189)	(187)	(8)
Amortization of prior service (cost)/credit	530	824	247	139	(38)	428	63
Amortization of net loss	(8,305)	(4,737)	(4,359)	(2,920)	(1,559)	(4,320)	(1,970)

Total	$471	$1,667	$11,721	($2,861)	($526)	($3,888)	$128
Total recognized as net periodic other postretirement cost, regulatory asset, and/or AOCI (before tax)	$18,578	$22,929	$33,792	$3,559	$3,660	$2,077	$5,763
Estimated amortization amounts from regulatory asset and/or AOCI to net periodic cost in the following year							
Prior service cost/(credit)	($530)	($824)	($247)	($139)	$38	($428)	($62)
Net loss	$8,163	$4,693	$5,149	$2,650	$1,587	$3,905	$1,915

2011	**Entergy Arkansas**	**Entergy Gulf States Louisiana**	**Entergy Louisiana**	**Entergy Mississippi**	**Entergy New Orleans**	**Entergy Texas**	**System Energy**
				(In Thousands)			
Other postretirement costs:							
Service cost - benefits earned during the period	$8,053	$6,158	$6,540	$2,632	$1,448	$3,074	$2,642
Interest cost on APBO	13,742	8,298	8,767	4,370	3,225	5,945	2,666
Expected return on assets	(11,528)	—	—	(3,906)	(3,200)	(7,496)	(2,115)
Amortization of transition obligation	821	239	383	352	1,190	187	9
Amortization of prior service cost/(credit)	(530)	(824)	(247)	(139)	38	(428)	(589)
Recognized net loss	6,436	2,896	2,793	2,160	968	2,803	1,477
Net other postretirement benefit cost	$16,994	$16,767	$18,236	$5,469	$3,669	$4,085	$4,090
Other changes in plan assets and benefit obligations recognized as a regulatory asset and/or AOCI (before tax)							
Arising this period:							
Net (gain)/loss	$32,241	$28,721	$24,837	$12,598	$8,946	$23,125	$8,499
Amounts reclassified from regulatory asset and/or AOCI to net periodic pension cost in the current year:							
Amortization of transition obligation	(821)	(239)	(383)	(352)	(1,190)	(187)	(9)
Amortization of prior service (cost)/credit	530	824	247	139	(38)	428	589
Amortization of net loss	(6,436)	(2,896)	(2,793)	(2,160)	(968)	(2,803)	(1,477)

Total	$25,514	$26,410	$21,908	$10,225	$6,750	$20,563	$7,602
Total recognized as net periodic other postretirement cost, regulatory asset, and/or AOCI (before tax)	$42,508	$43,177	$40,144	$15,694	$10,419	$24,648	$11,692
Estimated amortization amounts from regulatory asset and/or AOCI to net periodic cost in the following year							
Transition obligation	$820	$238	$382	$351	$1,189	$187	$8
Prior service cost/(credit)	($530)	($824)	($247)	($139)	$38	($428)	($63)
Net loss	$8,365	$4,778	$4,398	$2,926	$1,562	$4,329	$1,994

Other Postretirement Benefit Obligations, Plan Assets, Funded Status, and Amounts Not Yet Recognized and Recognized in the Balance Sheets of the Registrant Subsidiaries as of December 31, 2013 and 2012

2013	Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
				(In Thousands)			
Change in APBO							
Balance at beginning of year	$315,308	$207,987	$220,017	$100,508	$74,200	$142,114	$67,934
Service cost	9,619	7,910	8,541	3,246	1,752	3,760	3,580
Interest cost	13,545	8,964	9,410	4,289	3,135	6,076	2,945
Plan amendments	(11,617)	(8,705)	(18,844)	(4,714)	(4,469)	(5,359)	(4,591)
Curtailment	4,595	1,637	1,889	616	350	1,498	769
Plan participant contributions	4,564	1,998	2,509	1,292	915	1,498	860
Actuarial gain	(67,253)	(40,941)	(43,747)	(25,527)	(13,739)	(26,048)	(14,639)
Benefits paid	(18,764)	(8,958)	(11,524)	(5,416)	(4,464)	(8,455)	(3,912)
Medicare Part D subsidy received	737	410	513	245	194	334	105
Balance at end of year	$250,734	$170,302	$168,764	$74,539	$57,874	$115,418	$53,051
Change in Plan Assets							
Fair value of assets at beginning of year	$194,018	$—	$—	$62,951	$58,651	$115,824	$39,474
Actual return on plan assets	30,830	—	—	9,826	8,870	17,905	6,292
Employer contributions	21,015	6,960	9,015	4,785	2,567	4,846	5,387
Plan participant contributions	4,564	1,998	2,509	1,292	915	1,498	860
Benefits paid	(18,764)	(8,958)	(11,524)	(5,416)	(4,464)	(8,455)	(3,912)
Fair value of assets at end of year	$231,663	$—	$—	$73,438	$66,539	$131,618	$48,101
Funded status	($19,071)	($170,302)	($168,764)	($1,101)	$8,665	$16,200	($4,950)

Amounts recognized in the balance sheet							
Current liabilities	$—	($8,803)	($10,249)	$—	$—	$—	$—
Non-current liabilities	(19,071)	(161,499)	(158,515)	(1,101)	8,665	16,200	(4,950)
Total funded status	($19,071)	($170,302)	($168,764)	($1,101)	$8,665	$16,200	($4,950)
Amounts recognized in regulatory asset							
Prior service cost/(credit)	($12,996)	$—	$—	($5,056)	($4,335)	($6,505)	($4,702)
Net loss	40,272	—	—	9,304	6,485	22,772	10,297
	$27,276	$—	$—	$4,248	$2,150	$16,267	$5,595
Amounts recognized in AOCI (before tax)							
Prior service credit	$—	($10,359)	($19,390)	$—	$—	$—	$—
Net loss	—	31,577	35,001	—	—	—	—
	$—	$21,218	$15,611	$—	$—	$—	$—

2012	**Entergy Arkansas**	**Entergy Gulf States Louisiana**	**Entergy Louisiana**	**Entergy Mississippi**	**Entergy New Orleans**	**Entergy Texas**	**System Energy**
	(In Thousands)						
Change in APBO							
Balance at beginning of year	$290,613	$191,877	$196,352	$94,570	$69,316	$133,602	$60,526
Service cost	9,089	7,521	7,796	3,093	1,689	3,651	3,293
Interest cost	14,452	9,590	9,781	4,716	3,422	6,650	3,028
Plan participant contributions	4,440	1,945	2,725	1,269	742	1,526	820
Actuarial loss	13,256	5,818	16,215	1,625	3,240	2,645	2,861
Benefits paid	(17,873)	(9,543)	(13,760)	(5,199)	(4,605)	(6,604)	(2,764)
Medicare Part D subsidy received	1,331	779	908	434	396	644	170
Balance at end of year	$315,308	$207,987	$220,017	$100,508	$74,200	$142,114	$67,934
Change in Plan Assets							
Fair value of assets at beginning of year	$164,846	$—	$—	$54,452	$53,418	$105,181	$32,012
Actual return on plan assets	18,219	—	—	5,874	4,691	10,869	3,419
Employer contributions	24,386	7,598	11,035	6,555	4,405	4,852	5,987
Plan participant contributions	4,440	1,945	2,725	1,269	742	1,526	820
Benefits paid	(17,873)	(9,543)	(13,760)	(5,199)	(4,605)	(6,604)	(2,764)
Fair value of assets at end of year	$194,018	$—	$—	$62,951	$58,651	$115,824	$39,474
Funded status	($121,290)	($207,987)	($220,017)	($37,557)	($15,549)	($26,290)	($28,460)

Amounts recognized in the balance sheet							
Current liabilities	$—	($7,546)	($9,152)	$—	$—	$—	$—
Non-current liabilities	(121,290)	(200,441)	(210,865)	(37,557)	(15,549)	(26,290)	(28,460)
Total funded status	($121,290)	($207,987)	($220,017)	($37,557)	($15,549)	($26,290)	($28,460)
Amounts recognized in regulatory asset							
Prior service cost/(credit)	($2,146)	$—	$—	($566)	$114	($1,709)	($246)
Net loss	129,484	—	—	41,855	26,502	61,077	29,773
	$127,338	$—	$—	$41,289	$26,616	$59,368	$29,527
Amounts recognized in AOCI (before tax)							
Prior service credit	$—	($2,687)	($1,095)	$—	$—	$—	$—
Net loss	—	77,113	83,795	—	—	—	—
	$—	$74,426	$82,700	$—	$—	$—	$—

Non-Qualified Pension Plans

Entergy also sponsors non-qualified, non-contributory defined benefit pension plans that provide benefits to certain key employees.

The Registrant Subsidiaries (except System Energy) participate in Entergy's non-qualified, non-contributory defined benefit pension plans that provide benefits to certain key employees. The net periodic pension cost for their employees for the non-qualified plans for 2013, 2012, and 2011, was as follows:

	Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
			(In Thousands)			
2013	$448	$151	$12	$192	$92	$1,001
2012	$464	$158	$12	$183	$79	$648
2011	$498	$167	$14	$190	$65	$763

Included in the 2013 net periodic pension cost above are settlement charges of $415 thousand for Entergy Texas related to the lump sum benefits paid out of the plan. Included in the 2012 net periodic pension cost above are settlement charges of $38 thousand for Entergy Arkansas related to the lump sum benefits paid out of the plan. Included in the 2011 net periodic pension cost above are settlement charges of $41 thousand for Entergy Arkansas related to the lump sum benefits paid out of the plan.

The projected benefit obligation for their employees for the non-qualified plans as of December 31, 2013 and 2012 was as follows:

	Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
			(In Thousands)			
2013	$4,162	$2,511	$50	$1,752	$434	$7,910
2012	$4,323	$2,909	$116	$1,841	$457	$9,732

The accumulated benefit obligation for their employees for the non-qualified plans as of December 31, 2013 and 2012 was as follows:

	Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
	(In Thousands)					
2013	$3,765	$2,510	$50	$1,528	$387	$7,496
2012	$3,856	$2,899	$116	$1,590	$427	$9,127

The following amounts were recorded on the balance sheet as of December 31, 2013 and 2012:

2013	Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
	(In Thousands)					
Current liabilities	($367)	($262)	($6)	($118)	($20)	($786)
Non-current liabilities	(3,795)	(2,249)	(44)	(1,634)	(414)	(7,124)
Total funded status	($4,162)	($2,511)	($50)	($1,752)	($434)	($7,910)
Regulatory asset/(liability)	$1,979	$422	($87)	$637	($18)	($1,631)
Accumulated other comprehensive income (before taxes)	$—	$57	$—	$—	$—	$—

2012	Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
	(In Thousands)					
Current liabilities	($209)	($257)	($17)	($118)	($25)	($853)
Non-current liabilities	(4,114)	(2,652)	(99)	(1,723)	(432)	(8,879)
Total funded status	($4,323)	($2,909)	($116)	($1,841)	($457)	($9,732)
Regulatory asset/(liability)	$2,359	$679	($29)	$800	$88	($465)
Accumulated other comprehensive income (before taxes)	$—	$102	$—	$—	$—	$—

Accounting for Pension and Other Postretirement Benefits

Accounting standards require an employer to recognize in its balance sheet the funded status of its benefit plans. This is measured as the difference between plan assets at fair value and the benefit obligation. Entergy uses a December 31 measurement date for its pension and other postretirement plans. Employers are to record previously unrecognized gains and losses, prior service costs, and any remaining transition asset or obligation (that resulted from adopting prior pension and other postretirement benefits accounting standards) as comprehensive income and/or as a regulatory asset reflective of the recovery mechanism for pension and other postretirement benefit costs in the Registrant Subsidiaries' respective regulatory jurisdictions. For the portion of Entergy Gulf States Louisiana that is not regulated, the unrecognized prior service cost, gains and losses, and transition asset/obligation for its pension and other postretirement benefit obligations are recorded as other comprehensive income. Entergy Gulf States Louisiana and Entergy Louisiana recover other postretirement benefit costs on a pay as you go basis and record the unrecognized prior service cost, gains and losses, and transition obligation for its other postretirement benefit obligation as other comprehensive income. Accounting standards also requires that changes in the funded status be recorded as other comprehensive income and/or a regulatory asset in the period in which the changes occur.

With regard to pension and other postretirement costs, Entergy calculates the expected return on pension and other postretirement benefit plan assets by multiplying the long-term expected rate of return on assets by the market-related value (MRV) of plan assets. Entergy determines the MRV of pension plan assets by calculating a value that uses a 20-quarter phase-in of the difference between actual and expected returns. For other postretirement benefit plan assets Entergy uses fair value when determining MRV.

<u>Qualified Pension and Other Postretirement Plans' Assets</u>

The Plan Administrator's trust asset investment strategy is to invest the assets in a manner whereby long-term earnings on the assets (plus cash contributions) provide adequate funding for retiree benefit payments. The mix of assets is based on an optimization study that identifies asset allocation targets in order to achieve the maximum return for an acceptable level of risk, while minimizing the expected contributions and pension and postretirement expense.

In the optimization studies, the Plan Administrator formulates assumptions about characteristics, such as expected asset class investment returns, volatility (risk), and correlation coefficients among the various asset classes. The future market assumptions used in the optimization study are determined by examining historical market characteristics of the various asset classes, and making adjustments to reflect future conditions expected to prevail over the study period. Target asset allocations adjust dynamically based on the funded status of the pension plans. The following targets and ranges were established to produce an acceptable, economically efficient plan to manage around the targets. The target asset allocation range below for pension shows the ranges within which the allocation may adjust based on funded status, with the expectation that the allocation to fixed income securities will increase as the pension funded status increases. The target and range asset allocation for postretirement assets reflects changes made in 2012 as recommended in the latest optimization study

Entergy's qualified pension and postretirement weighted-average asset allocations by asset category at December 31, 2013 and 2012 and the target asset allocation and ranges are as follows:

Pension Asset Allocation	Target	Range	Actual 2013	Actual 2012
Domestic Equity Securities	45%	34% to 53%	46%	44%

International Equity Securities	20%	16%	to	24%	20%	20%
Fixed Income Securities	35%	31%	to	41%	33%	35%
Other	0%	0%	to	10%	1%	1%

Postretirement Asset Allocation	Non-Taxable						Taxable					
	Target	Range			Actual 2013	Actual 2012	Target	Range			Actual 2013	Actual 2012
Domestic Equity Securities	39%	34%	to	44%	40%	38%	39%	34%	to	44%	39%	39%
International Equity Securities	26%	21%	to	31%	26%	28%	26%	21%	to	31%	27%	27%
Fixed Income Securities	35%	30%	to	40%	34%	34%	35%	30%	to	40%	34%	34%
Other	0%	0%	to	5%	0%	0%	0%	0%	to	5%	0%	0%

In determining its expected long-term rate of return on plan assets used in the calculation of benefit plan costs, Entergy reviews past performance, current and expected future asset allocations, and capital market assumptions of its investment consultant and investment managers.

The expected long-term rate of return for the qualified pension plans' assets is based primarily on the geometric average of the historical annual performance of a representative portfolio weighted by the target asset allocation defined in the table above, along with other indications of expected return on current assets and expected return available for reinvestment. The time period reflected is a long dated period spanning several decades.

The expected long-term rate of return for the non-taxable postretirement trust assets is determined using the same methodology described above for pension assets, but the asset allocation specific to the non-taxable postretirement assets is used.

For the taxable postretirement trust assets, the investment allocation includes tax-exempt fixed income securities. This asset allocation in combination with the same methodology employed to determine the expected return for other trust assets (as described above), with a modification to reflect applicable taxes, is used to produce the expected long-term rate of return for taxable postretirement trust assets.

Concentrations of Credit Risk

Entergy's investment guidelines mandate the avoidance of risk concentrations. Types of concentrations specified to be avoided include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, geographic area and individual security issuance. As of December 31, 2013 all investment managers and assets were materially in compliance with the approved investment guidelines, therefore there were no significant concentrations (defined as greater than 10 percent of plan assets) of risk in Entergy's pension and other postretirement benefit plan assets.

Fair Value Measurements

Accounting standards provide the framework for measuring fair value. That framework provides a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements).

The three levels of the fair value hierarchy are described below:

- Level 1 - Level 1 inputs are unadjusted quoted prices for identical assets or liabilities in active markets that the Plan has the ability to access at the measurement date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

- Level 2 - Level 2 inputs are inputs other than quoted prices included in Level 1 that are, either directly or indirectly, observable for the asset or liability at the measurement date. Assets are valued based on prices derived by an independent party that uses inputs such as benchmark yields, reported trades, broker/dealer quotes, and issuer spreads. Prices are reviewed and can be challenged with the independent parties and/or overridden if it is believed such would be more reflective of fair value. Level 2 inputs include the following:

  - quoted prices for similar assets or liabilities in active markets;
  - quoted prices for identical assets or liabilities in inactive markets;
  - inputs other than quoted prices that are observable for the asset or liability; or
  - inputs that are derived principally from or corroborated by observable market data by correlation or other means.

  If an asset or liability has a specified (contractual) term, the Level 2 input must be observable for substantially the full term of the asset or liability.

- Level 3 - Level 3 refers to securities valued based on significant unobservable inputs.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The following tables set forth by level within the fair value hierarchy, measured at fair value on a recurring basis at December 31, 2013, and December 31, 2012, a summary of the investments held in the master trusts for Entergy's qualified pension and other postretirement plans in which the Registrant Subsidiaries participate.

Qualified Pension Trust

2013	Level 1		Level 2		Level 3	Total
			(In Thousands)			
Equity securities:						
Corporate stocks:						
Preferred	$6,847	(b)	$6,038	(a)	$—	$12,885
Common	915,996	(b)	—		—	915,996
Common collective trusts	—		1,753,958	(c)	—	1,753,958
Fixed income securities:						
U.S. Government securities	180,718	(b)	152,915	(a)	—	333,633
Corporate debt instruments	—		464,652	(a)	—	464,652
Registered investment companies	316,863	(d)	486,748	(e)	—	803,611
Other	—		129,169	(f)	—	129,169
Other:						
Insurance company general account (unallocated contracts)	—		36,886	(g)	—	36,886
Total investments	$1,420,424		$3,030,366		$—	$4,450,790
Cash						280
Other pending transactions						8,081
Less: Other postretirement assets included in total investments						(29,914)
Total fair value of qualified pension assets						$4,429,237

2012	Level 1		Level 2		Level 3	Total
			(In Thousands)			
Equity securities:						
Corporate stocks:						
Preferred	$861	(b)	$5,906	(a)	$—	$6,767
Common	787,132	(b)	—		—	787,132
Common collective trusts	—		1,620,315	(c)	—	1,620,315
Fixed income securities:						
U.S. Government securities	161,593	(b)	150,068	(a)	—	311,661
Corporate debt instruments	—		429,813	(a)	—	429,813
Registered investment companies	50,029	(d)	483,509	(e)	—	533,538
Other	—		111,001	(f)	—	111,001
Other:						
Insurance company general account (unallocated contracts)	—		36,252	(g)	—	36,252
Total investments	$999,615		$2,836,864		$—	$3,836,479
Cash						571

Other pending transactions	4,594
Less: Other postretirement assets included in total investments	(8,784)
Total fair value of qualified pension assets	$3,832,860

Other Postretirement Trusts

2013	Level 1		Level 2		Level 3	Total
			(In Thousands)			
Equity securities:						
Common collective trust	$—		$356,700	(c)	$—	$356,700
Fixed income securities:						
U.S. Government securities	40,808	(b)	43,471	(a)	—	84,279
Corporate debt instruments	—		50,563	(a)	—	50,563
Registered investment companies	4,163	(d)	—		—	4,163
Other	—		43,458	(f)	—	43,458
Total investments	$44,971		$494,192		$—	$539,163
Other pending transactions						773
Plus: Other postretirement assets included in the investments of the qualified pension trust						29,914
Total fair value of other postretirement assets						$569,850

2012	Level 1		Level 2		Level 3	Total
			(In Thousands)			
Equity securities:						
Common collective trust	$—		$314,478	(c)	$—	$314,478
Fixed income securities:						
U.S. Government securities	36,392	(b)	43,398	(a)	—	79,790
Corporate debt instruments	—		42,163	(a)	—	42,163
Registered investment companies	3,229	(d)	—		—	3,229
Other	—		39,846	(f)	—	39,846
Total investments	$39,621		$439,885		$—	$479,506
Other pending transactions						158
Plus: Other postretirement assets included in the investments of the qualified pension trust						8,784
Total fair value of other postretirement assets						$488,448

(a) Certain preferred stocks and fixed income debt securities (corporate, government, and securitized) are stated at fair value as determined by broker quotes.

(b) Common stocks, treasury notes and bonds, and certain preferred stocks and fixed income debt securities are stated at fair value determined by quoted market prices.

(c) The common collective trusts hold investments in accordance with stated objectives. The investment strategy of the trusts is to capture the growth potential of equity markets by replicating the performance of a specified index. Net asset value per share of the common collective trusts estimate fair value.

(d) The registered investment company is a money market mutual fund with a stable net asset value of one dollar per share.

(e) The registered investment company holds investments in domestic and international bond markets and estimates fair value using net asset value per share.

(f) The other remaining assets are U.S. municipal and foreign government bonds stated at fair value as determined by broker quotes.

(g) The unallocated insurance contract investments are recorded at contract value, which approximates fair value. The contract value represents contributions made under the contract, plus interest, less funds used to pay benefits and contract expenses, and less distributions to the master trust.

Accumulated Pension Benefit Obligation

The qualified pension accumulated benefit obligation for each of the Registrant Subsidiaries for their employees as of December 31, 2013 and 2012 was as follows:

	December 31,	
	2013	**2012**
	(In Thousands)	
Entergy Arkansas	$1,107,023	$1,161,448
Entergy Gulf States Louisiana	$530,974	$559,190
Entergy Louisiana	$697,945	$735,376
Entergy Mississippi	$318,941	$336,099
Entergy New Orleans	$150,239	$157,233
Entergy Texas	$332,484	$350,351
System Energy	$247,807	$251,378

Estimated Future Benefit Payments

Based upon the assumptions used to measure Entergy's qualified pension and other postretirement benefit obligations at December 31, 2013, and including pension and other postretirement benefits attributable to estimated future employee service, Entergy expects that benefits to be paid and the Medicare Part D subsidies to be received over the next ten years for the Registrant Subsidiaries will be as follows:

Estimated Future Qualified Pension Benefits Payments	**Entergy Arkansas**	**Entergy Gulf States Louisiana**	**Entergy Louisiana**	**Entergy Mississippi**	**Entergy New Orleans**	**Entergy Texas**	**System Energy**

(In Thousands)

Year(s)							
2014	$60,456	$23,039	$34,740	$16,920	$6,615	$18,583	$10,523
2015	$61,587	$24,260	$35,623	$17,669	$7,008	$19,137	$10,883
2016	$63,083	$25,556	$36,833	$18,515	$7,437	$19,744	$11,463
2017	$64,418	$27,111	$38,247	$19,298	$7,941	$20,402	$11,851
2018	$66,281	$28,962	$39,914	$20,237	$8,582	$21,140	$12,615
2019 - 2023	$375,976	$177,010	$229,821	$114,462	$51,610	$118,750	$77,880

Estimated Future Non-Qualified Pension Benefits Payments	**Entergy Arkansas**	**Entergy Gulf States Louisiana**	**Entergy Louisiana**	**Entergy Mississippi**	**Entergy New Orleans**	**Entergy Texas**
			(In Thousands)			
Year(s)						
2014	$367	$262	$6	$119	$20	$786
2015	$345	$240	$6	$115	$20	$701
2016	$299	$233	$6	$108	$20	$775
2017	$299	$279	$6	$105	$20	$690
2018	$279	$212	$5	$99	$19	$657
2019 - 2023	$1,916	$932	$21	$648	$223	$2,951

Estimated Future Other Postretirement Benefits Payments (before Medicare Part D Subsidy)	**Entergy Arkansas**	**Entergy Gulf States Louisiana**	**Entergy Louisiana**	**Entergy Mississippi**	**Entergy New Orleans**	**Entergy Texas**	**System Energy**
				(In Thousands)			
Year(s)							
2014	$17,122	$9,385	$10,967	$4,814	$5,044	$7,540	$2,858
2015	$15,513	$8,899	$10,049	$4,267	$4,475	$6,818	$2,783
2016	$15,523	$9,137	$10,162	$4,340	$4,448	$6,934	$2,786
2017	$15,554	$9,403	$10,289	$4,447	$4,423	$7,079	$2,875
2018	$15,987	$9,912	$10,796	$4,767	$4,502	$7,471	$2,984
2019 - 2023	$82,455	$55,934	$59,068	$25,819	$21,707	$40,067	$16,928

Estimated Future Medicare Part D Subsidy	**Entergy Arkansas**	**Entergy Gulf States Louisiana**	**Entergy Louisiana**	**Entergy Mississippi**	**Entergy New Orleans**	**Entergy Texas**	**System Energy**
				(In Thousands)			
Year(s)							
2014	$1,241	$582	$718	$462	$387	$563	$130

2015	$68	$32	$39	$25	$20	$30	$8
2016	$74	$35	$43	$27	$20	$32	$9
2017	$81	$38	$46	$29	$21	$34	$10
2018	$354	$165	$199	$123	$85	$141	$51
2019 - 2023	$2,252	$1,061	$1,235	$742	$455	$816	$379

Contributions

The expected 2014 pension and other postretirement plan contributions of the Registrant Subsidiaries for their employees are shown below. The required pension contributions will not be known with more certainty until the January 1, 2014 valuations are completed by April 1, 2014.

The Registrant Subsidiaries expect to contribute approximately the following to the qualified pension and other postretirement plans for their employees in 2014:

	Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
				(In Thousands)			
Pension Contributions	$93,591	$31,342	$52,885	$21,604	$10,482	$18,482	$21,257
Other Postretirement Contributions	$25,567	$9,385	$10,967	$—	$—	$4,645	$864

Actuarial Assumptions

The significant actuarial assumptions used in determining the pension PBO and the other postretirement benefit APBO as of December 31, 2013, and 2012 were as follows:

	2013	2012
Weighted-average discount rate:		
Qualified pension	5.04%-5.26% Blended 5.14%	4.31% - 4.50% Blended 4.36%
Other postretirement	5.05%	4.36%
Non-qualified pension	4.29%	3.37%
Weighted-average rate of increase in future compensation levels	4.23%	4.23%

The significant actuarial assumptions used in determining the net periodic pension and other postretirement benefit costs for 2013, 2012, and 2011 were as follows:

	2013	2012	2011
Weighted-average discount rate:			
Qualified pension	4.31% - 4.50%	5.10% - 5.20%	5.60% - 5.70%

Other postretirement	4.36%	5.10%	5.50%
Non-qualified pension	3.37%	4.40%	4.90%
Weighted-average rate of increase in future compensation levels	4.23%	4.23%	4.23%
Expected long-term rate of return on plan assets:			
Pension assets	8.50%	8.50%	8.50%
Other postretirement non-taxable assets	8.50%	8.50%	7.75%
Other postretirement taxable assets	6.50%	6.50%	5.50%

Entergy's other postretirement benefit transition obligations were amortized over 20 years ending in 2012.

The assumed health care cost trend rate used in measuring Entergy's December 31, 2013 APBO was 7.25% for pre-65 retirees and 7.00% for post-65 retirees for 2013, gradually decreasing each successive year until it reaches 4.75% in 2022 and beyond for both pre-65 and post-65 retirees. The assumed health care cost trend rate used in measuring Entergy's 2013 Net Other Postretirement Benefit Cost was 7.50% for pre-65 retirees and 7.25% for post-65 retirees for 2013, gradually decreasing each successive year until it reaches 4.75% in 2022 and beyond for both pre-65 and post-65 retirees.

A one percentage point change in the assumed health care cost trend rate for 2013 would have the following effects for the Registrant Subsidiaries for their employees:

	1 Percentage Point Increase		**1 Percentage Point Decrease**	
2013	**Impact on the APBO**	**Impact on the sum of service costs and interest cost**	**Impact on the APBO**	**Impact on the sum of service costs and interest cost**
		Increase/(Decrease) (In Thousands)		
Entergy Arkansas	$27,205	$3,275	($22,483)	($2,622)
Entergy Gulf States Louisiana	$21,873	$2,792	($17,958)	($2,219)
Entergy Louisiana	$18,025	$2,514	($15,012)	($2,031)
Entergy Mississippi	$8,235	$1,072	($6,819)	($858)
Entergy New Orleans	$4,995	$562	($4,242)	($461)
Entergy Texas	$13,439	$1,483	($11,170)	($1,189)
System Energy	$7,022	$1,064	($5,746)	($847)

Medicare Prescription Drug, Improvement and Modernization Act of 2003

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 became law. The Act introduces a prescription drug benefit cost under Medicare (Part D), which started in 2006, as well as a federal subsidy to employers who provide a retiree prescription drug benefit that is at least actuarially equivalent to

Medicare Part D.

The actuarially estimated effect of future Medicare subsidies and the actual subsidies received for the Registrant Subsidiaries for their employees was as follows:

	Entergy Arkansas	**Entergy Gulf States Louisiana**	**Entergy Louisiana**	**Entergy Mississippi**	**Entergy New Orleans**	**Entergy Texas**	**System Energy**
	Increase/(Decrease) In Thousands						
Impact on 12/31/2013 APBO	($9,639)	($4,875)	($5,580)	($3,060)	($1,769)	($3,324)	($1,973)
Impact on 12/31/2012 APBO	($62,877)	($32,055)	($36,015)	($19,507)	($10,902)	($21,164)	($13,586)
Impact on 2013 other postretirement benefit cost	($4,732)	($2,988)	($3,025)	($1,503)	($729)	($1,045)	($1,093)
Impact on 2012 other postretirement benefit cost	($5,791)	($3,660)	($3,643)	($1,799)	($995)	($1,321)	($1,400)
Impact on 2011 other postretirement benefit cost	($6,309)	($3,923)	($3,889)	($2,016)	($1,170)	($1,528)	($1,403)
Medicare subsidies received in 2013	$737	$410	$513	$245	$194	$334	$105

Defined Contribution Plans

Entergy sponsors the Savings Plan of Entergy Corporation and Subsidiaries (System Savings Plan). The System Savings Plan is a defined contribution plan covering eligible employees of Entergy and its subsidiaries. The employing Entergy subsidiary makes matching contributions for all non-bargaining and certain bargaining employees to the System Savings Plan in an amount equal to 70% of the participants' basic contributions, up to 6% of their eligible earnings per pay period. The 70% match is allocated to investments as directed by the employee.

Entergy also sponsors the Savings Plan of Entergy Corporation and Subsidiaries IV (established in 2002), the Savings Plan of Entergy Corporation and Subsidiaries VI (established in April 2007), and the Savings Plan of Entergy Corporation and Subsidiaries VII (established in April 2007) to which matching contributions are also made. The plans are defined contribution plans that cover eligible employees, as defined by each plan, of Entergy and its subsidiaries.

The Registrant Subsidiaries' 2013, 2012, and 2011 contributions to defined contribution plans for their employees were as follows:

Year	Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
			(In Thousands)			
2013	$3,351	$1,906	$2,393	$1,954	$769	$1,616
2012	$3,223	$1,842	$2,327	$1,875	$740	$1,601
2011	$3,183	$1,804	$2,260	$1,894	$725	$1,613

NOTE 12. STOCK-BASED COMPENSATION

Note 12 to the financial statements is not applicable to the Registrant Subsidiaries.

NOTE 13. BUSINESS SEGMENT INFORMATION

Registrant Subsidiaries

Each of the Registrant Subsidiaries has one reportable segment, which is an integrated utility business, except for System Energy, which is an electricity generation business. Each of the Registrant Subsidiaries' operations is managed on an integrated basis by that company because of the substantial effect of cost-based rates and regulatory oversight on the business process, cost structures, and operating results.

NOTE 14. EQUITY METHOD INVESTMENTS

See FERC Form 1 page 103 (Corporations Controlled by Respondent) and pages 224-225 (Investments in Subsidiary Companies).

NOTE 15. ACQUISITIONS AND DISPOSITIONS

Acquisitions

Hot Spring Energy Facility

In November 2012, Entergy Arkansas purchased the Hot Spring Energy Facility, a 620 MW combined-cycle natural gas turbine unit located in Malvern, Arkansas, from KGen Hot Spring LLC for approximately $253 million. The FERC and the APSC approved the transaction.

NOTE 16. RISK MANAGEMENT AND FAIR VALUES

Market Risk

The Utility has limited exposure to the effects of market risk because it operates primarily under cost-based rate regulation. To the extent approved by their retail regulators, the Utility operating companies hedge the exposure to price volatility inherent in their purchased power, fuel, and gas purchased for resale costs that are recovered from customers.

Derivatives

Some derivative instruments are classified as cash flow hedges due to their financial settlement provisions while others are classified as normal purchase/normal sale transactions due to their physical settlement provisions. Normal purchase/normal sale risk management tools include power purchase and sales agreements, fuel purchase agreements, capacity contracts, and tolling agreements. Financially-settled cash flow hedges can include natural gas and electricity swaps and options and interest rate swaps. Entergy may enter into financially settled swap and option contracts to manage market risk that may or may not be designated as hedging instruments.

In connection with joining MISO, Entergy received a direct allocation of FTRs in November 2013. FTRs are derivative instruments which represent economic hedges of future congestion charges that will be incurred in serving Entergy's load. They are not designated as hedging instruments. Entergy initially records FTRs at their estimated fair value and subsequently adjusts the carrying value to their estimated fair value at the end of each accounting period prior to settlement. Unrealized gains or losses on FTRs held by Entergy Wholesale Commodities are included in operating revenues. The Utility operating companies recognize regulatory liabilities or assets for unrealized gains or losses on FTRs. The total volume of FTRs outstanding as of December 31, 2013 is 37,647 GWh for Entergy, including 8,769 GWh for Entergy Arkansas, 6,125 GWh for Entergy Gulf States Louisiana, 9,202 GWh for Entergy Louisiana, 6,112 GWh for Entergy Mississippi, 1,402 GWh for Entergy New Orleans, and 6,038 GWh for Entergy Texas. Credit support for FTRs held by the Utility operating companies is covered by cash or letters of credit issued by each Entergy Utility operating company as required by MISO.

Due to regulatory treatment, the natural gas swaps are marked-to-market through fuel, fuel-related expenses, and gas purchased for resale and then such amounts are simultaneously reversed and recorded as an offsetting regulatory asset or liability. The gains or losses recorded as fuel expenses when the swaps are settled are recovered or refunded through fuel cost recovery mechanisms.

Due to regulatory treatment, the changes in the estimated fair value of FTRs are recorded through purchased power expenses and then such amounts are simultaneously reversed and recorded as an offsetting regulatory asset or liability. The gains or losses recorded as purchased power expense when the FTRs are settled are recovered or refunded through fuel cost recovery mechanisms.

The fair values of the Registrant Subsidiaries' derivative instruments not designated as hedging instruments on their balance sheets as of December 31, 2013 and 2012 are as follows:

Instrument	Balance Sheet Location	Fair Value	Registrant
2013			
Assets:			
Natural gas swaps	Gas hedge contracts	$2.2 million	Entergy Gulf States Louisiana
Natural gas swaps	Gas hedge contracts	$2.9 million	Entergy Louisiana
Natural gas swaps	Prepayments and other	$0.7 million	Entergy Mississippi
Natural gas swaps	Prepayments and other	$0.1 million	Entergy New Orleans
FTRs	Prepayments and other	$6.7 million	Entergy Gulf States Louisiana
FTRs	Prepayments and other	$5.7 million	Entergy Louisiana
FTRs	Prepayments and other	$1.0 million	Entergy Mississippi
FTRs	Prepayments and other	$2.0 million	Entergy New Orleans
FTRs	Prepayments and other	$18.4 million	Entergy Texas
2012			
Liabilities:			
Natural gas swaps	Gas hedge contracts	$2.6 million	Entergy Gulf States Louisiana
Natural gas swaps	Gas hedge contracts	$3.4 million	Entergy Louisiana
Natural gas swaps	Other current liabilities	$2.2 million	Entergy Mississippi

The effects of the Registrant Subsidiaries' derivative instruments not designated as hedging instruments on their income statements for the years ended December 31, 2013, 2012, and 2011 are as follows:

Instrument	Income Statement Location	Amount of gain (loss) recorded in income	Registrant
2013			
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	$4.5 million	Entergy Gulf States Louisiana
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	$6.0 million	Entergy Louisiana
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	$2.5 million	Entergy Mississippi
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	$0.1 million	Entergy New Orleans
FTRs	Purchased power expense	$(0.1) million	Entergy Arkansas
FTRs	Purchased power expense	$0.3 million	Entergy Gulf States Louisiana
FTRs	Purchased power expense	$0.2 million	Entergy Louisiana
FTRs	Purchased power expense	$1.0 million	Entergy Mississippi

FTRs	Purchased power expense	$1.2 million	Entergy New Orleans
FTRs	Purchased power expense	$0.8 million	Entergy Texas
2012			
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	($12.9 million)	Entergy Gulf States Louisiana
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	($16.2 million)	Entergy Louisiana
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	($11.2 million)	Entergy Mississippi
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	($1.5 million)	Entergy New Orleans
2011			
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	($17.9 million)	Entergy Gulf States Louisiana
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	($25.6 million)	Entergy Louisiana
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	($15.0 million)	Entergy Mississippi
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	($3.2 million)	Entergy New Orleans

Fair Values

The estimated fair values of Entergy's financial instruments and derivatives are determined using historical prices, bid prices, market quotes, and financial modeling. Considerable judgment is required in developing the estimates of fair value. Therefore, estimates are not necessarily indicative of the amounts that Entergy could realize in a current market exchange. Gains or losses realized on financial instruments other than those instruments held by the Entergy Wholesale Commodities business are reflected in future rates and therefore do not affect net income. Entergy considers the carrying amounts of most financial instruments classified as current assets and liabilities to be a reasonable estimate of their fair value because of the short maturity of these instruments.

Accounting standards define fair value as an exit price, or the price that would be received to sell an asset or the amount that would be paid to transfer a liability in an orderly transaction between knowledgeable market participants at the date of measurement. Entergy and the Registrant Subsidiaries use assumptions or market input data that market participants would use in pricing assets or liabilities at fair value. The inputs can be readily observable, corroborated by market data, or generally unobservable. Entergy and the Registrant Subsidiaries endeavor to use the best available information to determine fair value.

Accounting standards establish a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy establishes the highest priority for unadjusted market quotes in an active market for the identical asset or liability and the lowest priority for unobservable inputs. The three levels of the fair value hierarchy are:

- Level 1 - Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that the entity has the ability to access at the measurement date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of individually owned common stocks, cash equivalents (temporary cash investments, securitization recovery trust account, and escrow accounts), debt instruments, and gas hedge contracts. Cash equivalents includes all unrestricted highly liquid debt instruments with an original or remaining maturity of three months or less at the date of purchase.

- Level 2 - Level 2 inputs are inputs other than quoted prices included in Level 1 that are, either directly or indirectly, observable for the asset or liability at the measurement date. Assets are valued based on prices derived by independent third parties that use inputs such as benchmark yields, reported trades, broker/dealer quotes, and issuer spreads. Prices are reviewed and can be challenged with the independent parties and/or overridden by Entergy if it is believed such would be more reflective of fair value. Level 2 inputs include the following:

  - quoted prices for similar assets or liabilities in active markets;
  - quoted prices for identical assets or liabilities in inactive markets;
  - inputs other than quoted prices that are observable for the asset or liability; or
  - inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 2 consists primarily of individually-owned debt instruments or shares in common trusts. Common trust funds are stated at estimated fair value based on the fair market value of the underlying investments.

- Level 3 - Level 3 inputs are pricing inputs that are generally less observable or unobservable from objective sources. These inputs are used with internally developed methodologies to produce management's best estimate of fair value for the asset or liability. Level 3 consists primarily of FTRs and derivative power contracts used as cash flow hedges of power sales at merchant power plants.

The values of FTRs are based on unobservable inputs, including estimates of future congestion costs in MISO between applicable sink and source pricing nodes based on prices published by MISO. They are classified as Level 3 assets and liabilities. The valuations of these assets and liabilities were performed by the Entergy Wholesale Commodities Back Office for the unregulated business, and by the Risk Control Group within System Planning and Operations for the Utility operating companies. Entergy's Accounting Policy group evaluated these valuations, with the assistance of others within the organization with knowledge of the various inputs and assumptions used in the valuation. The Risk Control Group within System Planning and Operations performed a similar role for the Utility operating companies that the Entergy Wholesale Commodities Back Office performed for the unregulated business. The Risk Control Group within System Planning and Operations reported to the Vice President - System Planning. The Accounting Policy group reported to the Vice President, Corporate Controller.

The following table sets forth, by level within the fair value hierarchy, the Registrant Subsidiaries' assets that are accounted for at fair value on a recurring basis as of December 31, 2013 and December 31, 2012. The assessment of the significance of a particular input to a fair value measurement requires judgment and may affect its placement within the fair value hierarchy levels.

Entergy Arkansas

2013	Level 1	Level 2	Level 3	Total
	(In Millions)			
Assets:				
Temporary cash investments	$122.8	$—	$—	$122.8
Decommissioning trust funds (a):				
Equity securities	13.6	449.7	—	463.3
Debt securities	58.6	189.0	—	247.6
Securitization recovery trust account	3.8	—	—	3.8
Escrow accounts	26.0	—	—	26.0
	$224.8	$638.7	$—	$863.5

2012	Level 1	Level 2	Level 3	Total
	(In Millions)			
Assets:				
Temporary cash investments	$24.9	$—	$—	$24.9
Decommissioning trust funds (a):				
Equity securities	9.5	374.5	—	384.0
Debt securities	94.3	122.3	—	216.6
Securitization recovery trust account	4.4	—	—	4.4
Escrow accounts	38.0	—	—	38.0
	$171.1	$496.8	$—	$667.9

(a) The decommissioning trust funds hold equity and fixed income securities. Equity securities are invested to approximate the returns of major market indices. Fixed income securities are held in various governmental and corporate securities. See Note 17 for additional information on the investment portfolios.

The following table sets forth a reconciliation of changes in the net assets (liabilities) for the fair value of derivatives classified as Level 3 in the fair value hierarchy for the year ended December 31, 2013.

	Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
				(In Millions)		
Balance as of January 1,	$—	$—	$—	$—	$—	$—
Issuances of FTRs	—	7.2	6.2	1.1	2.2	20.0
Unrealized gains (losses) included						

as a regulatory liability/asset	(0.1)	(0.2)	(0.3)	0.9	1.0	(0.8)
Settlements	0.1	(0.3)	(0.2)	(1.0)	(1.2)	(0.8)
Balance as of December 31,	$—	$6.7	$5.7	$1.0	$2.0	$18.4

NOTE 17. DECOMMISSIONING TRUST FUNDS

Entergy holds debt and equity securities, classified as available-for-sale, in nuclear decommissioning trust accounts. The NRC requires Entergy subsidiaries to maintain trusts to fund the costs of decommissioning ANO 1, ANO 2, River Bend, Waterford 3, and Grand Gulf. The funds are invested primarily in equity securities, fixed-rate debt securities, and cash and cash equivalents.

Entergy records decommissioning trust funds on the balance sheet at their fair value. Because of the ability of the Registrant Subsidiaries to recover decommissioning costs in rates and in accordance with the regulatory treatment for decommissioning trust funds, the Registrant Subsidiaries have recorded an offsetting amount of unrealized gains/(losses) on investment securities in other regulatory liabilities/assets. For the nonregulated portion of River Bend, Entergy Gulf States Louisiana has recorded an offsetting amount of unrealized gains/(losses) in other deferred credits. Accordingly, unrealized gains recorded on the assets in these trust funds are recognized in the accumulated other comprehensive income component of shareholders’ equity because these assets are classified as available for sale. Unrealized losses (where cost exceeds fair market value) on the assets in these trust funds are also recorded in the accumulated other comprehensive income component of shareholders’ equity unless the unrealized loss is other than temporary and therefore recorded in earnings. Generally, Entergy records realized gains and losses on its debt and equity securities using the specific identification method to determine the cost basis of its securities.

Entergy Arkansas

Entergy Arkansas holds debt and equity securities, classified as available-for-sale, in nuclear decommissioning trust accounts. The securities held as of December 31, 2013 and 2012 are summarized as follows:

	Fair Value	**Total Unrealized Gains**	**Total Unrealized Losses**
		(In Millions)	
2013			
Equity Securities	$463.3	$214.0	$—
Debt Securities	247.6	5.3	5.2
Total	$710.9	$219.3	$5.2
2012			
Equity Securities	$384.0	$116.1	$—
Debt Securities	216.6	14.5	0.2
Total	$600.6	$130.6	$0.2

The amortized cost of debt securities was $248.9 million as of December 31, 2013 and $202.3 million as of December 31, 2012. As of December 31, 2013, the debt securities have an average coupon rate of approximately 2.73%, an average duration of approximately 4.82 years, and an average maturity of approximately 5.52 years. The equity securities are generally held in funds that are designed to approximate the return of the Standard & Poor's 500 Index. A relatively small percentage of the securities are held in funds intended to replicate the return of the Wilshire 4500 Index.

The fair value and gross unrealized losses of available-for-sale equity and debt securities, summarized by investment type and length of time that the securities have been in a continuous loss position, are as follows as of December 31, 2013:

	Equity Securities		Debt Securities	
	Fair Value	**Gross Unrealized Losses**	**Fair Value**	**Gross Unrealized Losses**
	(In Millions)			
Less than 12 months	$—	$—	$153.2	$4.8
More than 12 months	—	—	6.9	0.4
Total	$—	$—	$160.1	$5.2

The fair value and gross unrealized losses of available-for-sale equity and debt securities, summarized by investment type and length of time that the securities have been in a continuous loss position, are as follows as of December 31, 2012:

	Equity Securities		Debt Securities	
	Fair Value	**Gross Unrealized Losses**	**Fair Value**	**Gross Unrealized Losses**
	(In Millions)			
Less than 12 months	$0.2	$—	$24.4	$0.2
More than 12 months	—	—	1.0	—
Total	$0.2	$—	$25.4	$0.2

The fair value of debt securities, summarized by contractual maturities, as of December 31, 2013 and 2012 are as follows:

	2013	**2012**
	(In Millions)	
less than 1 year	$8.1	$8.8
1 year - 5 years	110.9	98.6
5 years - 10 years	118.0	93.1
10 years - 15 years	3.9	5.1
15 years - 20 years	0.9	—

20 years+	5.8	11.0
Total	$247.6	$216.6

During the years ended December 31, 2013, 2012, and 2011, proceeds from the dispositions of securities amounted to $266.4 million, $144.3 million, and $125.4 million, respectively. During the years ended December 31, 2013, 2012, and 2011, gross gains of $16.8 million, $3.4 million, and $3.9 million, respectively, and gross losses of $0.6 million, $0.1 million, and $0.2 million, respectively, were recorded in earnings.

NOTE 18. VARIABLE INTEREST ENTITIES

Note 18 to the financial statements is not applicable to the presentation in the FERC Form 1.

NOTE 19. TRANSACTIONS WITH AFFILIATES

Each Registrant Subsidiary purchases electricity from or sells electricity to the other Registrant Subsidiaries, or both, under rate schedules filed with FERC. The Registrant Subsidiaries receive management, technical, advisory, operating, and administrative services from Entergy Services; receive management, technical, and operating services from Entergy Operations; and until the first quarter 2011 purchased fuel from System Fuels. These transactions are on an “at cost” basis. In addition, Entergy Power sells electricity to Entergy Arkansas, Entergy Louisiana, and Entergy New Orleans.

As described in Note 1 to the financial statements, all of System Energy’s operating revenues consist of billings to Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans.

As described in Note 4 to the financial statements, the Registrant Subsidiaries participate in Entergy’s money pool and earn interest income from the money pool. Entergy Arkansas, Entergy Mississippi, and Entergy New Orleans also received interest income from System Fuels until the first quarter 2011, when System Fuels repaid each company’s investment in System Fuels.

The tables below contain the various affiliate transactions of the Utility operating companies, System Energy, and other Entergy affiliates.

Intercompany Revenues

	Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
				(In Millions)			
2013	$349.9	$383.1	$114.9	$107.3	$27.0	$369.4	$735.1
2012	$324.0	$380.6	$138.2	$36.1	$43.9	$313.2	$622.1
2011	$293.8	$574.5	$139.0	$125.1	$96.9	$264.1	$563.4

Intercompany Operating Expenses

	Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
	(In Millions)						
	(a)	(b)	(c)		(d)		
2013	$656.1	$672.8	$667.6	$399.0	$279.6	$418.1	$175.2
2012	$580.7	$532.3	$597.4	$352.7	$247.2	$386.1	$147.4
2011	$752.7	$563.1	$574.0	$337.2	$226.6	$486.6	$131.5

(a) Includes $3.3 million in 2013, $1.4 million in 2012, and $1.2 million in 2011 for power purchased from Entergy Power.

(b) Includes power purchased from RS Cogen of $3.2 million in 2013, $2.8 million in 2012, and $41.1 million in 2011.

(c) Includes power purchased from Entergy Power of $8.1 million in 2013, $14.3 million in 2012, and $14.5 million in 2011.

(d) Includes power purchased from Entergy Power of $8.0 million in 2013, $14.1 million in 2012, and $14.2 million in 2011.

Intercompany Interest and Investment Income

	Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
	(In Millions)						
2013	$—	$27.5	$78.2	$—	$—	$—	$—
2012	$—	$28.2	$78.2	$—	$—	$0.1	$—
2011	$0.1	$32.5	$78.1	$0.1	$0.1	$—	$0.6

NOTE 20. QUARTERLY FINANCIAL DATA

Note 20 to the financial statements is not applicable to the presentation of the FERC Form 1.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				
5	Balance of Account 219 at End of Preceding Quarter/Year				
6	Balance of Account 219 at Beginning of Current Year				
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				
10	Balance of Account 219 at End of Current Quarter/Year				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	8,337,944,974	8,337,944,974
4	Property Under Capital Leases	1,064,228	1,064,228
5	Plant Purchased or Sold		
6	Completed Construction not Classified	541,970,419	541,970,419
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	8,880,979,621	8,880,979,621
9	Leased to Others		
10	Held for Future Use	1,086,768	1,086,768
11	Construction Work in Progress	217,578,963	217,578,963
12	Acquisition Adjustments	21,824,442	21,824,442
13	Total Utility Plant (8 thru 12)	9,121,469,794	9,121,469,794
14	Accum Prov for Depr, Amort, & Depl	4,110,040,882	4,110,040,882
15	Net Utility Plant (13 less 14)	5,011,428,912	5,011,428,912
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	3,805,740,325	3,805,740,325
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	303,023,309	303,023,309
22	Total In Service (18 thru 21)	4,108,763,634	4,108,763,634
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation	178,367	178,367
29	Amortization		
30	Total Held for Future Use (28 & 29)	178,367	178,367
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	1,098,881	1,098,881
33	Total Accum Prov (equals 14) (22,26,30,31,32)	4,110,040,882	4,110,040,882

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
					7
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					31
					32
					33

Schedule Page: 200 Line No.: 4 Column: c

Includes general plant assets only.

Schedule Page: 200 Line No.: 21 Column: c

Consists of accumulated provision for amortization of intangible assets.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials	66,262,175	11,436,531
4	Allowance for Funds Used during Construction	3,862,001	2,690,069
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	70,124,176	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)	229,196,765	88,102,240
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	-4,503,409	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	303,824,350	
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
		77,698,706	3
		6,552,070	4
			5
		84,250,776	6
			7
			8
			9
			10
			11
81,723,112		235,575,893	12
-2,429,312		-2,074,097	13
		321,900,766	14
			15
			16
			17
			18
			19
			20
			21
			22

Schedule Page: 202 Line No.: 12 Column: f

FUEL LEASE FOR ARKANSAS NUCLEAR ONE
LESSOR: RIVER FUEL TRUST #1

<u>Investment of River Fuel Trust #1 at December 31, 2013</u>

Investment at December 31, 2012	$229,196,765
Additional investment in fuel	85,652,246
Daily lease charges allocated to and included in capitalized costs	2,449,994
Less: Burn-up charges paid to lessor	81,723,112
Total Investment at December 31, 2013	$235,575,893

Cost Incurred under River Fuel Trust #1 Lease for the
Year Ended December 31, 2013

Daily Lease Charges	$7,283,987
Fuel Burn-Up Charges	81,723,112
Total	$89,007,099

As of December 31, 2013, arrangements to lease nuclear fuel existed in an aggregate amount up to $270 million for Entergy Arkansas. The lessors finance the acquisition and ownership of nuclear fuel through loans made under revolving credit agreements, the issuance of commercial paper, and the issuance of intermediate-term notes. The credit agreements for Entergy Arkansas have a termination date of June 26, 2016. The intermediate-term notes issued pursuant to these fuel lease arrangements have varying maturities through December 15, 2017. It is expected that additional financing under the leases will be arranged as needed to acquire additional fuel, to pay interest, and to pay maturing debt. However, if such additional financing cannot be arranged, the lessee in each case must repurchase sufficient nuclear fuel to allow the lessor to meet its obligations in accordance with the fuel lease.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	33,366	
3	(302) Franchises and Consents	3,832,306	
4	(303) Miscellaneous Intangible Plant	361,155,608	15,656,347
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	365,021,280	15,656,347
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	2,128,382	
9	(311) Structures and Improvements	85,781,350	433,080
10	(312) Boiler Plant Equipment	492,141,910	8,614,618
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	190,224,426	2,707,381
13	(315) Accessory Electric Equipment	76,876,903	927,993
14	(316) Misc. Power Plant Equipment	17,764,246	41,498
15	(317) Asset Retirement Costs for Steam Production	775,616	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	865,692,833	12,724,570
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	2,648,089	
19	(321) Structures and Improvements	431,088,300	49,680,482
20	(322) Reactor Plant Equipment	1,186,443,283	11,005,985
21	(323) Turbogenerator Units	298,894,801	46,884,578
22	(324) Accessory Electric Equipment	254,275,648	19,342,876
23	(325) Misc. Power Plant Equipment	233,171,671	1,011,365
24	(326) Asset Retirement Costs for Nuclear Production	63,301,902	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	2,469,823,694	127,925,286
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	1,304,463	
28	(331) Structures and Improvements	2,831,412	11,218
29	(332) Reservoirs, Dams, and Waterways	14,996,744	
30	(333) Water Wheels, Turbines, and Generators	14,472,371	400,413
31	(334) Accessory Electric Equipment	1,111,602	2,129,019
32	(335) Misc. Power PLant Equipment	2,155,723	
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production	7,341	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	36,879,656	2,540,650
36	D. Other Production Plant		
37	(340) Land and Land Rights	2,364,820	6
38	(341) Structures and Improvements	269,374,611	44,257
39	(342) Fuel Holders, Products, and Accessories	712,464	1,227,638
40	(343) Prime Movers	28,875,938	1,619,335
41	(344) Generators	312,710,143	14,033
42	(345) Accessory Electric Equipment	5,657,244	113,869
43	(346) Misc. Power Plant Equipment	2,286,614	164,908
44	(347) Asset Retirement Costs for Other Production	23,762	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	622,005,596	3,184,046
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	3,994,401,779	146,374,552

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	54,011,897	4,405,064
49	(352) Structures and Improvements	39,286,836	9,478,241
50	(353) Station Equipment	589,200,980	36,077,213
51	(354) Towers and Fixtures	144,214,953	36,273
52	(355) Poles and Fixtures	320,913,053	10,924,601
53	(356) Overhead Conductors and Devices	308,688,336	24,633,561
54	(357) Underground Conduit	18,865	
55	(358) Underground Conductors and Devices	39,153	
56	(359) Roads and Trails	1,899,889	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,458,273,962	85,554,953
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,832,402	
61	(361) Structures and Improvements	14,391,498	1,342,655
62	(362) Station Equipment	351,076,814	11,846,930
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	503,104,134	28,509,027
65	(365) Overhead Conductors and Devices	410,928,277	39,985,124
66	(366) Underground Conduit	89,904,542	1,483,506
67	(367) Underground Conductors and Devices	139,963,751	2,952,348
68	(368) Line Transformers	669,436,451	47,840,925
69	(369) Services	247,286,890	13,093,664
70	(370) Meters	128,855,953	3,446,347
71	(371) Installations on Customer Premises	36,277,042	3,400,854
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	80,895,931	2,315,968
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,676,953,685	156,217,348
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware	106,951	
80	(383) Computer Software	5,941,521	
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)	6,048,472	
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	4,645,550	850,741
87	(390) Structures and Improvements	78,720,383	15,569,501
88	(391) Office Furniture and Equipment	29,674,079	3,328,401
89	(392) Transportation Equipment	12,879	
90	(393) Stores Equipment	1,141,219	-9,460
91	(394) Tools, Shop and Garage Equipment	14,873,897	555,817
92	(395) Laboratory Equipment	1,180,377	
93	(396) Power Operated Equipment	233,491	
94	(397) Communication Equipment	41,801,289	2,894,799
95	(398) Miscellaneous Equipment	3,387,684	192,464
96	SUBTOTAL (Enter Total of lines 86 thru 95)	175,670,848	23,382,263
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	175,670,848	23,382,263
100	TOTAL (Accounts 101 and 106)	8,676,370,026	427,185,463
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	8,676,370,026	427,185,463

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			33,366		2
			3,832,306		3
			376,811,955		4
			380,677,627		5
					6
					7
83			2,128,299		8
14,946,931			71,267,499		9
61,690,893		85,076	439,150,711		10
					11
54,226,335		-18,166	138,687,306		12
17,841,652		-66,910	59,896,334		13
3,521,789			14,283,955		14
			775,616		15
152,227,683			726,189,720		16
					17
			2,648,089		18
4,007,059			476,761,723		19
11,822,854			1,185,626,414		20
7,022,193			338,757,186		21
1,448,853			272,169,671		22
1,419,730			232,763,306		23
			63,301,902		24
25,720,689			2,572,028,291		25
					26
			1,304,463		27
			2,842,630		28
			14,996,744		29
218,735			14,654,049		30
619			3,240,002		31
			2,155,723		32
					33
			7,341		34
219,354			39,200,952		35
					36
			2,364,826		37
49,758			269,369,110		38
202,710			1,737,392		39
4,839,408			25,655,865		40
1,964,617			310,759,559		41
1,577,686			4,193,427		42
17,590			2,433,932		43
			23,762		44
8,651,769			616,537,873		45
186,819,495			3,953,956,836		46

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
699		-1,745,959	56,670,303		48
1,096		-1,886,555	46,877,426		49
6,966,685		-848,245	617,463,263		50
35,607		1,124	144,216,743		51
3,281,464		20,294	328,576,484		52
1,171,704		57,789	332,207,982		53
			18,865		54
			39,153		55
			1,899,889		56
					57
11,457,255		-4,401,552	1,527,970,108		58
					59
455		1,739,806	6,571,753		60
8,024		1,886,555	17,612,684		61
840,847		574,156	362,657,053		62
					63
1,950,275		-155,617	529,507,269		64
4,640,632		29,936,346	476,209,115		65
626,291		143,277	90,905,034		66
1,141,673		1,160,470	142,934,896		67
5,089,216		-30,852,323	681,335,837		68
216,578		-40,559	260,123,417		69
3,166,669		-389	129,135,242		70
1,564,173		1,203,189	39,316,912		71
					72
193,311		-1,199,512	81,819,076		73
					74
19,438,144		4,395,399	2,818,128,288		75
					76
					77
					78
			106,951		79
			5,941,521		80
					81
					82
					83
			6,048,472		84
					85
		19,447	5,515,738		86
1,064,283		-13,294	93,212,307		87
4,107,635			28,894,845		88
			12,879		89
83,045			1,048,714		90
295,371			15,134,343		91
319,788			860,589		92
			233,491		93
30,623			44,665,465		94
24,457			3,555,691		95
5,925,202		6,153	193,134,062		96
					97
					98
5,925,202		6,153	193,134,062		99
223,640,096			8,879,915,393		100
					101
					102
					103
223,640,096			8,879,915,393		104

Schedule Page: 204   Line No.: 90   Column: c

The negative project additions represent reversal credits from prior year additions for unclassified project costs closed to plant in service.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Little Rock Ne 500kv Transmission Substation	1974		283,935
3	Land and Land Rights Under $250,000	Various		582,679
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Other Property Under $250,000	Various		220,154
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			1,086,768

Name of Respondent Entergy Arkansas, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	DISTRIBUTION LINES PLANT:	
2	ICE STORM DL ARK DIST EAI 12/4/13	5,722,994
3	IMP.INST.NEW CKT W.ELM AND GRAHAM R	674,666
4	GOVERNMENT MANDATED: AHTD, 100653 M	643,364
5	IMPROVE: MR13-001V N424-RECONDUCT	601,477
6	LAWSON ROAD SUB EXITS	548,595
7	IMPROVE: RECOND EXIST CKT N650/N630	500,108
8	DISTR UG NETWORK INSP/MTCE EAI	451,176
9	STORM DL ARK DIST EAI 10/30/13	388,740
10	IMPROVE: COLONEL GLENN, RECONDUCTOR	317,754
11	INSTALL NEW CKT K160 TO RIVER MARKE	291,608
12	DISTR PRIVATE AREA LIGHT MTCE EAI	289,990
13	IMPROVE: VILONIA SUBSTATION EXITS N	266,756
14	WOODWARD TO MCCAMANT T-LINE - DISTR	263,867
15	STORM DL ARK DIST EAI 9/20/13	255,711
16	IMPROVE: VILONIA SUB CKT N930 NAYLO	234,337
17	LAWSON SUBSTATION CONDUIT INSTALLAT	217,541
18	SR13-005C CKT N464- R/P 1-#6CU W/ 3	210,849
19	IMPROVE: VILONIA SUB CKT N910 HWY 6	192,744
20	PINE BLUFF:TARGET:CIRCUIT C454	192,466
21	HIGHWAY: HWY 394 - CR 80 INDEPENDA	177,613
22	BLYTHEVILLE NE ALT FEEDERS 288 & 10	177,014
23	ALT PROGRAM: SUBSTATION - BLYTHEVIL	152,245
24	IMPROVEMENT: CROSSETT / HAMBURG L38	129,834
25	ALT: G620/V640: INSTALL ONE-WAY ALT	124,410
26	IMPROVE: HWY 230 CAVE CITY, RECOND	123,968
27	IMPROVEMENT: FISHER, PROJ. HB14-005	110,540
28	IMPROVEMENT: SKUNK HOLLOW RD ADD A	110,234
29	OTHER DISTRIBUTION LINES PLANT	773,870
30		
31	GENERAL AND INTANGIBLE PLANT:	
32	EAI DEC 2013 ICE STORM ACCRUAL	20,259,819
33	ANO1 RISK BASED FIRE PROT (NFPA805)	12,192,014
34	RADIO SYS REPL EAI REP, CON, PORT	3,832,163
35	RTO IMPLEMENT SOFTWARE	2,477,822
36	ANO2 PHASE II - NFPA 805 TRANSITION	2,402,706
37	SAP UPGRADE SOFTWARE	2,351,979
38	SMARTZONE RADIO SYS REPL OVERSIGHT	637,605
39	RTO IMPLEMENT METERS EAI	427,319
40	SMARTZONE RADIO SYS REPL EAI STATNS	408,461
41	ANO2 IMPLEMENT LICENSE RENEWAL COMM	379,829
42	SUBSTATION 4-WIRE UPGRADE-EAI	374,673
43	TOTAL	217,578,963

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Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	SYSTEMWIDE ERGONOMICS CAPITAL - EAI	303,666
2	DRY FUEL CASK VSC-24 LICENSE RENEWA	299,784
3	BLYTHEVILLE YARD IMPROVEMENTS	283,555
4	SHAREPOINT - ENTERPRISE SEARCH TOOL	275,050
5	WARREN SC ADDITION	220,308
6	2013-CUSTSYS-CCS REG COMPL-EAI	206,922
7	2012 CE -WELCOME EXPERIENCE REL 2	206,335
8	TALENT MANAGEMENT SOLUTION (TMS)	197,983
9	AR GRID; PURCHASE GROUNDING EQUIP	194,656
10	SAFETY INFORMATION MANAGEMENT & REP	170,985
11	CMDB DEPLOYMENT/BMC SOFTWARE	162,605
12	RCRC-CENTRALIZED LOGGING	156,795
13	ITSW-RTO HIGH AVAILABLITY COLLECTIV	153,828
14	SQL VIRTUALIZATION - 2013	143,239
15	SAFETY:INSULATED MATS & TOOLS EAI	140,427
16	PDW APPLICATION CONVERSION	134,242
17	CETARC BLDG A- MASONRY WALL REPAIR	116,399
18	XEN MOBILE - 2013	115,114
19	OTHER GENERAL AND INTANGIBLE PLANT	1,792,731
20		
21	PRODUCTION PLANT:	
22	ANOC CONSTRUCT CASK TRANSFER FACILI	18,757,454
23	ANO STORAGE PAD AND RAIL SYSTEM UPG	7,253,519
24	ANO DRY FUEL STORAGE (2015 CAMPAIGN	7,124,693
25	ANO DRY FUEL STORAGE (2014 CAMPAIGN	7,113,385
26	ANO1 IMPLEMENT LICENSE RENEWAL COMM	7,050,469
27	ANO1 FUKUSHIMA FLEX MODS	5,570,256
28	ANO DRY FUEL STORAGE (2013 CAMPAIGN	3,996,808
29	ANOC CONSTRUCT BUILDING FOR CTF	3,260,343
30	ANO-2 CEDM PURCHASE	3,017,080
31	RD3 TURBINE RUNNER REPLACEMENT AND	2,662,242
32	U2 MODS RESULTING FROM NFPA805	2,391,344
33	ANO2 INSTALL AUX XFMR (2X-02)	2,264,617
34	WB1 CAVR SCRUBBER,STACK,BURNERS	2,260,654
35	WB2 CAVR SCRUBBER,STACK,BURNERS	2,228,977
36	ANO2 UNDERGROUND PIPING REPLACEMENT	1,690,876
37	ANO2 REPLACE 2P-32D MOTOR WITH SPAR	1,598,369
38	PURCHASE REACTOR VESSEL STUD TENSIO	1,411,692
39	WB1 MATS COMPLIANCE - CAPITAL	1,170,598
40	WB2 MATS COMPLIANCE - CAPITAL	1,156,393
41	ANO2 EDG EXCITER/VOLTAGE REG REPL	1,122,732
42	IN1 MATS COMPLIANCE - CAPITAL	947,115
43	TOTAL	217,578,963

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	WB1 UNIT 1 ABSORBER AREA	931,265
2	WB1 UNIT 1 BAGHOUSE	879,254
3	ANO2 REPL P-32D N9000 SEAL	844,086
4	WB2 UNIT 2 BAGHOUSE	819,241
5	WBC REAGENT PREP SYSTEM	803,691
6	WB2 UNIT 2 ABSORBER AREA	738,196
7	ANO2 REPL 2CV-1010-1 MSIV ACTUATOR	650,544
8	DECLARATORY ORDER FOR WB SCRUBBER	592,159
9	ANO1 REBUILD/REPL P-3D CIRC WATER P	519,177
10	ANO1 UNDERGROUND PIPING REPLACEMENT	490,954
11	HT1 - OIS IMPLEMENTATION	449,136
12	WB2 FLUE GAS SYSTEM	436,409
13	WB1 FLUE GAS SYSTEM	430,842
14	WBC DCS (FGD UNITS)	381,961
15	ANO1 REACTOR BLDG DRAIN HDR REPL	356,816
16	ANO1 FUKUSHIMA SPENT FUEL POOL INST	339,633
17	ANO2 FUKUSHIMA FLEX MODS	326,927
18	WB1 BOOSTER FANS	316,933
19	WB2 BOOSTER FANS	316,933
20	HT1 - WAREHOUSE DESIGN ENGINEERING	292,002
21	ANO1 FUKUSHIMA EP EQUIPMENT	289,529
22	ANOC PURCHASE VOTES INFINITY SYSTEM	285,268
23	HT1- BENTLEY NEVADA VIBRATION MONIT	265,963
24	ANO2 COOLING TOWER FILL REPLACEMENT	263,953
25	2R23 SW PIPING REPL (RB COOLERS)	259,993
26	ANOC PURCHASE HOIST FOR DRY FUEL SU	256,937
27	ANO1 MODS RESULTING FROM NFPA 805	241,076
28	HT1 - PLANT METERING	223,512
29	ANO2 RVLMS OBSOLETE EQUIP	218,212
30	ANO2 REPL 2P-32C RCP N9000 SEAL	215,038
31	ANO1 UPGRADE MAIN STEAM SAFETY VLV	198,723
32	U1 REPLACE PRESSURIZER HEATER BUNDL	197,599
33	ANO2 REFURB TURBINE STOP VALVES	196,830
34	ANOC REMODEL OFFICE AREA IN CSB-3 N	170,145
35	ANO2 2P-1B MFP OVERHAUL	169,216
36	INSTALL UNITERUPTIBLE POWER SUPPLY	166,903
37	ANOC REPL YOKOGAWA RECORDERS	165,173
38	ANO2 REPL 2P-3B CIRC WATER MOTOR	163,388
39	ANO2 REPL 2SI-3A LPSI DISCH VLV	142,549
40	ANOC INSTALL PUMPS FOR MANHOLES	141,430
41	ANO1 PURCHASE GAP SCANNER TOOL	140,837
42	ANO2 FUKUSHIMA SPENT FUEL POOL INST	122,486
43	TOTAL	217,578,963

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	HT1 CARD READER SECURITY ACCESS	113,942
2	ANO2 REPL MISC SOLENOID VALVES	106,230
3	ANO2 UPGRADE 2SI-15C SIT TO RCS VLV	102,888
4	OTHER PRODUCTION PLANT	1,790,764
5		
6	TRANSMISSION AND DISTRIBUTION SUBSTATION PLANT:	
7	LAWSON RD BUILD SUBSTATION.	5,940,547
8	KEO EHV; RPLC CONTROL HOUSE & EQUIP	3,767,405
9	DRIVER BUILD NEW 500/230KV SUB	2,264,279
10	LR ALEXANDER - ADD TRANSFORMER	2,176,095
11	HS ALBRIGHT SUB: PURCHASE PROPERTY	1,353,247
12	EAI:PURCHS SPARE 500-230KV AXFMR	1,328,720
13	CAMDEN N: NEW LINE BAY & BREAKER	1,203,635
14	CAMDEN MAGUIRE: NEW LINE BAY & BRKR	953,748
15	LAWSON RD SITE PURCHASE	664,948
16	VILONIA BUILD 40MVA DIST SUB	628,249
17	RTO METERING - RITCHIE 230 KV	511,066
18	PB MCCAMANT UPGRADE WOODWARD BAY	477,549
19	DATTO; FLD REGULATOR AND SWITCHES	424,040
20	WOODWARD UPGRADE MCCAMANT LINE BAY	400,083
21	EL DORADO EHV:LIFE EXTENSION #2	397,766
22	EAI:PUCH SPARE 13.8KV VOLTAGE REG	329,437
23	LAKE VILLAGE: NEW LINE BAY & BRKR	314,249
24	LR PINNACLE, RPLC B4869	292,217
25	WOODWARD 230KV RING BUS	276,768
26	COFER RD:BUILD NEW 161KV D-SUB	267,062
27	WDWRD UPGRADE WATSON CHAPEL BKR BAY	245,800
28	EAI:PURCH SPARE 34.5KV VOLTAGE REG	202,846
29	GIFORD; RPLC HS CS B0500	194,232
30	CIP4-ED NERC ELDORADO SUBST	190,955
31	CIP4-ED NERC DELL AECC SUBST	188,335
32	EAI:PURCH 20 BUSHINGS FOR ANO AXFMR	185,156
33	CIP4-ED NERC PLEASANT HILL SUBST	170,765
34	WOODWARD; RPLC 3 RELAY PANELS	160,506
35	PB SOUTH UPGRADE WDWRD LINE PANEL	156,604
36	CIP4-ED NERC WEST MEMPHIS SUBST	146,346
37	CIP4-ED NERC MABELVALE SUBST	145,573
38	CIP4-ED NERC SHERIDAN SUBST	144,140
39	CIP4-ED NERC WRIGHTSVILLE SUBST	139,642
40	CIP4-ED NERC MCNEIL SUBST	133,750
41	BUILD NEW SUB AT SMACKOVER	128,138
42	LR ALEXANDER - ADD TRANSFORMER	124,826
43	TOTAL	217,578,963

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	CIP4-ED NERC SANS SOUCI SUBST	124,272
2	BRINKLEY E.; RPLC BREAKER B8076	124,025
3	LR HINDMAN, RPLC FLD DEADEND TWRS	121,666
4	MANILA SUBSTATION, REPLACE D25 RTU	118,689
5	CIP4-ED NERC KEO SUBSTATION	116,228
6	EAI:PURCH 3 500KV CTS FOR BREAKER	111,599
7	LR GAINES RELAY UPGRADE	109,905
8	WHITE BLUFF RECONFIGURE 500KV STA.	107,864
9	SWPPP CLOSE-OUT / GROUND GRID	103,071
10	OTHER TRANSMISSION AND DISTRIBUTION SUBSTATION PLANT	2,460,862
11		
12	TRANSMISSION LINE PLANT:	
13	CAMDEN N-CAMDEN MAGUIRE	4,832,329
14	WOODWARD/MCCAMANT UPGRADE	2,662,176
15	LIDAR - L858 MAYFLWER - PLSNT HILLS	1,295,280
16	LK VLLG BGBY-MCN LK: NEW 230KV	1,099,190
17	KEO - WM EHV, RPL STRUCTURES	1,016,660
18	ELAINE - GILLETT, REPLACE POLES	940,975
19	NEWPORT - PARKIN, RPL 32 STRUCTURES	933,654
20	HOT SPRINGS MILTON TO HS ALBRIGHT	813,474
21	MONTICELLO EAST/REED NEW 115KV LINE	721,856
22	CALICO ROCK-MELBOURNE TLINE UPGRADE	645,937
23	AECC HYDRO-GILLETT	645,510
24	SKYLINING - L970 WDWARD - LA ST LN	418,069
25	LIDAR - L869 ELDORADO - LA ST LINE	411,464
26	LK VLLG-MCN LK: 115KV REBUILD	372,992
27	WOODWARD/WATSON CHAPEL REBUILD LINE	319,273
28	BENTON WEST CUT IN	299,268
29	BRINKLEY EAST - MOSES, REPL 9 STRS	287,945
30	LIDAR - L857 MABELVALE - MAYFLOWER	238,332
31	SKYLINING - L837 PNGBRN - STHSIDE	226,482
32	CONWAY W - MRRLTN E, REPL STRS	216,904
33	LYNCH - JACKSONVILLE 115KV T-LINE	207,947
34	NEWPORT - PARKIN, REPL 9 STRS	207,936
35	MINOR ADD TO WO# C6PPTLA161	206,878
36	SKYLINING - L966 MBLVL - BLAKLY DAM	202,235
37	ELAINE - GILLETT, REPLACE CROSSARMS	168,493
38	SKYLINING - L806 KEO - HLLND BOTMS	150,753
39	LIDAR - L865 HOT SPRNGS-ETTA-MCNEIL	148,940
40	SKYLINING - L977 WDWRD - PB ARSNAL	144,529
41	KEO - WM EHV, INSTALL BIRD GUARDS	142,032
42	SKYLINING - L844 PLST HILLS - GRNBR	135,887
43	TOTAL	217,578,963

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	CAMDEN N-CAMDEN MAGUIRE: NEW ROW	135,018
2	LIDAR - L852 MABLEVALE - OG&E	119,039
3	SKYLINING - L909 SAGE - MT. VIEW	115,289
4	OTHER TRANSMISSION LINES PLANT	146,413
5		
6	UNDISTRIBUTED OVERHEADS	85,055
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
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43	TOTAL	217,578,963

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	3,831,715,522	3,831,537,155	178,367	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	205,028,750	205,028,750		
4	(403.1) Depreciation Expense for Asset Retirement Costs	-161,986	-161,986		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	204,866,764	204,866,764		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	223,640,096	223,640,096		
13	Cost of Removal	45,045,566	45,045,566		
14	Salvage (Credit)	38,020,832	38,020,832		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	230,664,830	230,664,830		
16	Other Debit or Cr. Items (Describe, details in footnote):	1,236	1,236		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	3,805,918,692	3,805,740,325	178,367	

Section B. Balances at End of Year According to Functional Classification

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
20	Steam Production	562,809,245	562,809,245		
21	Nuclear Production	1,372,076,472	1,372,076,472		
22	Hydraulic Production-Conventional	13,601,398	13,590,007	11,391	
23	Hydraulic Production-Pumped Storage				
24	Other Production	283,851,297	283,851,297		
25	Transmission	454,390,548	454,312,891	77,657	
26	Distribution	1,034,252,813	1,034,252,813		
27	Regional Transmission and Market Operation	103,174	103,174		
28	General	84,833,745	84,744,426	89,319	
29	TOTAL (Enter Total of lines 20 thru 28)	3,805,918,692	3,805,740,325	178,367	

Schedule Page: 219 Line No.: 3 Column: c

Excludes service company depreciation allocations of $7,065,531 (included in the depreciation expense shown on page 336), since these allocations do not offset to accumulated depreciation reserves.

Schedule Page: 219 Line No.: 16 Column: c

Net (Gain)/Loss closed to Accumulated Reserve.

Schedule Page: 219 Line No.: 20 Column: c

Includes $922,127 for asset retirement obligations.

Schedule Page: 219 Line No.: 21 Column: c

Includes $63,301,902 for asset retirement obligations.

Schedule Page: 219 Line No.: 22 Column: c

Includes $19,114 for asset retirement obligations.

Schedule Page: 219 Line No.: 24 Column: c

Includes $12,733 for asset retirement obligations.

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	The Arklahoma Corporation			
2	Common Stock - 238 shares	5/16/47		64,872
3	Equity in Earnings - 47.6% Ownership			133,827
4	Subtotal			198,699
5				
6	System Fuels, Inc.			
7	Common Stock - 70 shares	01/04/72		7,000
8	Subtotal			7,000
9				
10	Entergy Arkansas Restoration Funding, LLC	6/17/10		
11	Capital Contribution			620,600
12	Undistributed retained earnings			-738,299
13	Subtotal			-117,699
14				
15	Transmission Company Arkansas, LLC			
16	Capital Contribution			1,000
17	Subtotal			1,000
18				
19	Arkansas Power & Light Company			
20	Capital Contribution			1,000
21	Subtotal			1,000
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	90,000

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		64,872		2
-292		133,535		3
-292		198,407		4
				5
				6
		7,000		7
		7,000		8
				9
				10
		620,600		11
-333,950	-219	-1,072,468		12
-333,950	-219	-451,868		13
				14
				15
		1,000		16
		1,000		17
				18
				19
	49,600	50,600		20
	49,600	50,600		21
				22
				23
				24
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				37
				38
				39
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				41
-334,242	49,381	-194,861		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	44,975,227	38,687,468	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	3,914,439	2,706,461	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	94,335,718	97,002,432	Electric
8	Transmission Plant (Estimated)	17,515,012	17,154,961	Electric
9	Distribution Plant (Estimated)	15,766,477	17,228,158	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	127,617,207	131,385,551	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	21,064,545	21,043,896	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	197,571,418	193,823,376	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2014 No. (d)	2014 Amt. (e)
1	Balance-Beginning of Year	71,291.00			
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	32,667.00		32,667.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	23,463.00			
19	Other:				
20	Prior year adjustment	4,650.00			
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	75,845.00		32,667.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA	436.00		436.00	
38	Deduct: Returned by EPA				
39	Cost of Sales	436.00		436.00	
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	436.00	143		
45	Gains	436.00	143		
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2015		2016		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						71,291.00		1
								2
								3
32,667.00		32,667.00		882,022.00		1,012,690.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						23,463.00		18
								19
						4,650.00		20
								21
								22
								23
								24
								25
								26
								27
								28
32,667.00		32,667.00		882,022.00		1,055,868.00		29
								30
								31
								32
								33
								34
								35
								36
436.00		436.00		18,563.00		20,307.00		37
								38
436.00		436.00		18,563.00		20,307.00		39
								40
								41
								42
								43
						436.00	143	44
						436.00	143	45
								46

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2014 No. (d)	2014 Amt. (e)
1	Balance-Beginning of Year	4,862.00	85,810		
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	5,211.00		3,056.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:	3,489.00	82,261		
9	Less Purchases Billed	-4,437.00	-44,266		
10	Purchases not Billed	3,230.00	76,850		
11	Hot Spring Acquisition		4		
12	PY Adjustment		-266		
13					
14					
15	Total	2,282.00	114,583		
16					
17	Relinquished During Year:				
18	Charges to Account 509	5,981.00	82,131		
19	Other:				
20	Prior Adj account 509	519.00	8,016		
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	5,855.00	110,246	3,056.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2015		2016		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						4,862.00	85,810	1
								2
								3
2,369.00		2,417.00		1,964.00		15,017.00		4
								5
								6
								7
						3,489.00	82,261	8
						-4,437.00	-44,266	9
						3,230.00	76,850	10
							4	11
							-266	12
								13
								14
						2,282.00	114,583	15
								16
								17
						5,981.00	82,131	18
								19
						519.00	8,016	20
								21
								22
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								26
								27
								28
2,369.00		2,417.00		1,964.00		15,661.00	110,246	29
								30
								31
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Schedule Page: 229 Line No.: 4 Column: j

Reflects issuances for 2017.

Schedule Page: 229 Line No.: 8 Column: b

Counterparty	No.	Amount
American Electric Power	477	$10,971
Koch Supply Trading	2,198	53,789
Exelon Generation Company	814	17,501
	------	-------
Grand Total	3,489	$82,261
	======	=======

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Income Taxes	115,899,369	800,000	282; 283	8,058,352	108,641,017
2						
3	Grand Gulf 1 Costs - Under Recovery	17,292,093	6,235,635			23,527,728
4						
5	ISES Synchronization Adjustment					
6	Docket 82-314-U, Amort 30 years	272,316		407.3	272,316	
7						
8	TCA/Ice Storm Settlement - Docket 01-296-U					
9	and Docket 01-084-U, Amort 30 years	10,006,488		407.3	526,656	9,479,832
10						
11	System Agreement Costs Under Collection	127,217,425		557	124,233,677	2,983,748
12						
13	Asset Retirement Obligation - Nuclear	203,952,301	26,251,223	*	11,123,194	219,080,330
14						
15	Asset Retirement Obligation - Fossil	6,208,644	305,147			6,513,791
16						
17	Asset Retirement Obligation - Hydro	49,086	2,213			51,299
18						
19	Asset Retirement Obligation - Other	226,345	14,220			240,565
20						
21	Defined Benefit Pension and Other					
22	Postretirement Plans	831,184,218	15,405,824	**	329,452,335	517,137,707
23						
24	System Agreement Cost Equalization		30,000,000			30,000,000
25						
26	Deferred Storm Restoration Costs					
27	APSC Docket 09-031-U	21,938,229	12,282,159			34,220,388
28						
29	Federal Litigation Consulting Fees	528,999	621,244			1,150,243
30						
31	Deferred Fuel Under-Recovery		65,712,633			65,712,633
32						
33	2009 EAI Rate Case - Docket 09-084-U					
34	Amort period 42 months beg July 2010	947,809		***	947,809	
35						
36	MISO transition costs deferral per FERC Letter					
37	Order No. AC11-130 and APSC Docket No.					
38	10-0411-U Order No. 76	1,139,586	29,769,261			30,908,847
39						
40	2013 EAI Rate Case - APSC Docket 13-028-U	806,190		****	806,190	
41						
42	Energy Efficiency Rider - Under Recovery 07-085-TF	2,346,289	10,178,718			12,525,007
43						
44	TOTAL	1,340,015,387	228,729,897		475,420,529	1,093,324,755

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Human Capital Management cost deferral					
2	APSC Docket 13-028-U, Recovery thru		22,485,857			22,485,857
3	retails rates thru June 2017					
4						
5	MOARK agreement - APSC Docket 13-028-U		8,665,763			8,665,763
6						
7						
8						
9	* 407.3, 409.1					
10	** 107,926,410.1,411.1,253,228.3					
11	***403,408.1,588,903,920,921,923,926,928					
12	****403,408.1,517,560,908,920,921,923,926,928					
13						
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42						
43						
44	TOTAL	1,340,015,387	228,729,897		475,420,529	1,093,324,755

Schedule Page: 232 Line No.: 24 Column: a

Production Cost Equalization Proceeding

The Utility operating companies historically have engaged in the coordinated planning, construction, and operation of generating and bulk transmission facilities under the terms of the System Agreement, which is a rate schedule that has been approved by the FERC. Certain of the Utility operating companies' retail regulators and other parties are pursuing litigation involving the System Agreement at the FERC. The proceedings include challenges to the allocation of costs as defined by the System Agreement and allegations of imprudence by the Utility operating companies in their execution of their obligations under the System Agreement.

In June 2005, the FERC issued a decision in the System Agreement litigation that reallocates total production costs of the Utility operating companies whose relative total production costs expressed as a percentage of Entergy System average production costs are outside an upper or lower bandwidth. Under the current circumstances, this will be accomplished by payments from Utility operating companies whose production costs are more than 11% below Entergy System average production costs to Utility operating companies whose production costs are more than the Entergy System average production cost, with payments going first to those Utility operating companies whose total production costs are farthest above the Entergy System average.

Management believes that any changes in the allocation of production costs resulting from the FERC's decision and related retail proceedings should result in similar rate changes for retail customers. The APSC has approved a production cost allocation rider for recovery from customers of the retail portion of the costs allocated to Entergy Arkansas. After a FERC decision on requests for rehearing, in 2007, Entergy Arkansas recorded accounts payable and Entergy Gulf States Louisiana, Entergy Louisiana, Entergy Mississippi, and Entergy Texas recorded accounts receivable to reflect the rough production cost equalization payments and receipts required to implement the FERC's remedy based on calendar year 2006 production costs. Entergy Arkansas recorded a corresponding regulatory asset for its right to collect the payments from its customers, and Entergy Gulf States Louisiana, Entergy Louisiana, Entergy Mississippi, and Entergy Texas recorded corresponding regulatory liabilities for their obligations to pass the receipts on to their customers. The utility operating companies have followed this same accounting practice each year since then.

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Non-Expense Accrued Labor	3,100,832	712,633			3,813,465
2						
3	Section 263A	1,190,846		930.2	73,632	1,117,214
4						
5	Securitization Financing Costs					
6	Docket 10-008-U					
7	Amort pd 8/18/10-8/1/21	177,914		930.2	20,728	157,186
8						
9	Agric Irrig AMI Load Cntrol					
10	Docket 08-072-TF	9,613,043	2,209,831	930.2	760,883	11,061,991
11						
12	Pooled Equipment - PEICo		635,981			635,981
13						
14	Other	67,066	8,916	Various	8,569	67,413
15						
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43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	14,149,701				16,853,250

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	See Footnote Detail	716,793,200	581,685,024
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	716,793,200	581,685,024
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	716,793,200	581,685,024

Notes

Schedule Page: 234 Line No.: 2 Column: a

	Balance at Beg of Year	Balance at End of Year
Interest on Tax Deficiencies	$387,152	$73,352
ANO Shutdown Costs	(211,577)	(446,226)
Grand Gulf 1 - Over/Under Recovery	(6,782,823)	(9,228,751)
Taxable Unbilled Revenue	27,651,419	37,824,958
Property Insurance	(5,316,646)	(13,422,947)
Capitalized Repairs	1,652,686	1,499,711
Injuries & Damages Reserve	1,625,901	1,764,766
Customer Deposits	1,756,468	1,191,436
Unfunded Pension	(77,654,921)	(79,350,997)
Minimum Pension Liability	327,255,975	190,753,415
Supplemental Pension	666,263	(238,140)
Other Retirement Benefits	(14,739,098)	(15,026,856)
Deferred Fuel Cost	(50,068,470)	(26,946,155)
Removal Cost	21,379,523	16,746,182
Nuclear Decommissioning	(761,262)	-
Accrued Medical Claims	3,028,600	2,895,268
Uncollectible Accounts	5,263,050	5,957,542
Regulatory Liability	(436)	-
Partnership Income/Loss	(1,266)	-
Contract Deferred Revenue	657	657
Environmental Reserve	563,143	489,136
Incentive Compensation	1,455,678	4,405,319
ANO Building Sale/Leaseback Tax Gain	109,963	77,776
Employee Stock Investment Plan	25,808	-
Long-Term Incentive Compensation	633,119	42,561
Stock Options	1,394,825	1,378,527
Restricted Stock Awards	137,198	236,502
Deferred Director's Compensation	(59,245)	218
Rate Refund	476,492	695,032
EPA Allowances	738,943	(11,720)
Severance Accrual	-	1,067,391
Accounts Payable Accrual	2,587,413	4,028,382
Income tax Adjustment	35,148,628	34,777,222
Net Operating Loss Carryforward	440,952,750	423,391,850
Contribution Carryforward	1,147,343	-
Tax Credit Carryforward	2,100,187	2,315,195
State Taxes	(5,950,240)	(5,455,582)
FIN 48 Adjustment	200,000	200,000
	$716,793,200	$581,685,024

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	ACCOUNT 201: Common Stock			
2	Common - par value	325,000,000	0.01	
3	Total Account 201: Common Stock	325,000,000		
4				
5	ACCOUNT 204: Preferred Stock			
6	4.32% Preferred - Cumulative	70,000	100.00	103.65
7	4.72% Preferred - Cumulative	93,500	100.00	107.00
8	4.56% Preferred - Cumulative	75,000	100.00	102.83
9	4.56% Preferred - 1965 Series Cumulative	75,000	100.00	102.50
10	6.08% Preferred - Cumulative	100,000	100.00	102.83
11	6.45% Preferred - Cumulative	3,000,000	25.00	25.00
12	Total Account 204: Preferred Stock	3,413,500		
13				
14				
15	Unissued Series:			
16	$100 par value	3,316,500		
17	$25 par value	6,000,000		
18	$.01 par value	15,000,000		
19	Total unissued	24,316,500		
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22				
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CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
46,980,196	469,802					2
46,980,196	469,802					3
						4
						5
70,000	7,000,000					6
93,500	9,350,000					7
75,000	7,500,000					8
75,000	7,500,000					9
100,000	10,000,000					10
3,000,000	75,000,000					11
3,413,500	116,350,000					12
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OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	ACCOUNT 208: Donations Received from Stockholders - None	
2		
3	ACCOUNT 209: Reduction in Par or Stated Value of Capital Stock	
4	From $12.50 to $0.01 (1987)	586,782,648
5		
6	ACCOUNT 210: Gain on Resale or Cancellation of Reacquired	
7	Capital Stock - None	
8		
9	ACCOUNT 211: Miscellaneous Paid-in-Capital - None	
10		
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40	TOTAL	586,782,648

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Capital Stock Expense - Common Stock	1,802,833
2		
3		
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21		
22	TOTAL	1,802,833

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221 - BONDS - MORTGAGE BONDS:		
2	5.9% Series	100,000,000	1,041,860
3			319,000 D
4	5.0% Series	115,000,000	939,967
5			696,900 D
6	6.38% Series	60,000,000	609,720
7			59,400 D
8	5.66% Series	175,000,000	1,725,102
9			47,250 D
10	5.4% Series	300,000,000	2,191,131
11			21,000 D
12	5.75% Series	225,000,000	7,400,537
13			
14	3.75% Series	350,000,000	2,518,954
15			101,500 D
16	4.9% Series	200,000,000	6,777,506
17			
18	3.05% Series	250,000,000	1,989,513
19			705,000 D
20	4.75% Series	125,000,000	4,151,566
21			
22	TOTAL ACCOUNT 221	1,900,000,000	31,295,906
23			
24	ACCOUNT 224 - OTHER LONG-TERM DEBT:		
25	POLLUTION CONTROL BONDS:		
26	Independence County 5.0% Series	45,000,000	586,176
27			
28	Jefferson County 4.6% Series 2006	54,700,000	638,559
29			
30	Independence County 2.375% Series 2013	45,000,000	508,717
31			
32	Jefferson County 1.55% Series 2013	54,700,000	493,941
33	TOTAL	2,099,400,000	33,523,299

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			
2	SOLID WASTE DISPOSAL BONDS:		
3	Department of Energy (Nuclear Fuel Disposal Cost)		
4			
5	LONG-TERM OBLIGATIONS:		
6	Little Rock Air Force Base distribution facilities 4.2%		
7			
8	Term Loan		
9			
10	TOTAL ACCOUNT 224	199,400,000	2,227,393
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	2,099,400,000	33,523,299

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
06/11/2003	06/01/2033	06/11/2003	06/01/2033	100,000,000	5,900,000	2
						3
06/25/2003	07/01/2018	06/25/2003	07/01/2018	115,000,000	5,750,000	4
						5
10/12/2004	11/01/2034	10/12/2004	11/01/2034	60,000,000	3,828,000	6
						7
01/19/2005	02/01/2025	01/19/2005	02/01/2025	175,000,000	9,905,000	8
						9
07/17/2008	08/01/2013	07/17/2008	08/01/2013		9,450,000	10
						11
10/08/2010	11/01/2040	10/08/2010	11/01/2040	225,000,000	12,937,500	12
						13
11/12/2010	02/15/2021	11/12/2010	02/15/2021	350,000,000	13,125,000	14
						15
12/13/2012	12/01/2052	12/13/2012	12/01/2052	200,000,000	9,800,000	16
						17
05/30/2013	06/01/2023	05/30/2013	06/01/2023	250,000,000	4,469,097	18
						19
06/04/2013	06/01/2063	06/04/2013	06/01/2063	125,000,000	3,414,062	20
						21
				1,600,000,000	78,578,659	22
						23
						24
						25
03/29/2005	01/01/2021	03/29/2005	01/01/2021		206,250	26
						27
06/13/2006	10/01/2017	06/13/2006	10/01/2017		230,652	28
						29
01/09/2013	01/01/2021	01/09/2013	01/01/2021	45,000,000	1,045,000	30
						31
01/09/2013	10/01/2017	01/09/2013	10/01/2017	54,700,000	829,009	32
				2,133,054,842	82,282,568	33

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
				181,253,324	96,484	3
						4
						5
				2,101,518	88,571	6
						7
				250,000,000	1,207,943	8
						9
				533,054,842	3,703,909	10
						11
						12
						13
						14
						15
						16
						17
						18
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						22
						23
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						25
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						28
						29
						30
						31
						32
				2,133,054,842	82,282,568	33

Schedule Page: 256 Line No.: 1 Column: i

Total interest for Accounts 221 and 224 is recorded in Account 427, as shown on page 117, line 62.

Schedule Page: 256 Line No.: 10 Column: h

Mortgage Bond 5.4% Series was retired on August 1, 2013.

Schedule Page: 256 Line No.: 26 Column: h

Independence County 5.0% Series was refunded on February 4, 2013, with proceeds from Independence County 2.375% issuance.

Schedule Page: 256 Line No.: 28 Column: h

Jefferson County 4.6% Series was refunded on February 4, 2013, with proceeds from Jefferson County 1.55% issuance.

Schedule Page: 256.1 Line No.: 8 Column: i

The weighted average rate was 1.13%. The term loan is due January 2015.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	161,948,513
2		
3		
4	Taxable Income Not Reported on Books	
5	See Footnote Detail	17,681,205
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	See Footnote Detail	146,118,483
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	See Footnote Detail	13,366,791
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See Footnote Detail	415,660,376
21		
22		
23	Reconciling Items for the Year - See Footnote Detail	29,023,222
24		
25		
26		
27	Federal Tax Net Income	-74,255,744
28	Show Computation of Tax:	
29		
30	Est Federal Taxable Income ($74,255,744) @35%	-25,989,510
31		
32	Federal Tax Accrual for the Current Year	-25,989,510
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44	Estimated Consolidated Federal Income Tax	16,386,000

Schedule Page: 261 Line No.: 5 Column: a

Taxable Income Not Reported on Books:

Taxable Unbilled Revenue	$9,363,218
Contributions in Aid of Construction	2,666,438
TCBY Tower	1,481,266
Interest Capitalized	4,170,283

Total	$17,681,205
	============

Schedule Page: 261 Line No.: 10 Column: a

Deductions on Books Not Deducted for Return:

Nuclear Fuel Expense	$81,723,112
Interest on Tax Deficiency	(800,000)
Securitization	(1,144,132)
Property Insurance Reserve	(12,282,159)
Increase in Reserves	(2,169,129)
Deferred Nuclear Shutdown Costs	(598,214)
Reserve for Uncollectible Accounts	1,770,408
Non-deductible Meals & Entertainment	419,621
TCA/Ice Storm settlement	526,656
Amortization of Bond Reacquisition Losses	2,663,137
Maintenance Refueling Reserve	7,275,550
Long Term Incentive Plan	69,446
Deferral of Grand Gulf Cost per Settlement	(6,235,635)
Non-deductible Penalties	113,720
Non-deductible PAC & Political Expenses	1,379,891
Pension Expense	17,390,382
Restricted Stock	253,165
Research & Experimentation	2,471,880
Reorganization Costs	6,966,097
Option Grant	(35,243)
Rate Refund	557,146
Accounts Payable	3,737,115
Reversal of AFUDC equity & net-of-tax	9,733,653
Depreciation-Reverse prior flow-through	14,579,929
Incentive Comp	12,601,576
Severance Accrual	2,721,199
Decommissioning - Dry Cask	2,429,312

Total	$146,118,483
	============

Schedule Page: 261 Line No.: 15 Column: a

Income Recorded on Books Not Included in Return:

Amortization of Gain on Sale of Property	$82,048
Equity in Domestic Subs	(292)
IPP Advances	1,440,489
Allowance for Funds Used During Construction	11,844,546

Total	$13,366,791
	===========

Schedule Page: 261 Line No.: 20 Column: a

Deductions on Return Not Charged Against Book Income:

Excess of Tax over Book Depreciation	$37,960,564
Property Book/Tax Diff-PowerTax	199,082,112
Daily Lease Charges	2,449,420
Early Retiree Reimbursement	(240,317)
Vegetation Management	6,677,111
Deferred Fuel Expense	(58,521,045)
Regulatory Capitalized Costs	10,416,528
Pension and Hospital Reserve	717,421
Mark to Market-Other Contracts	1,633,000
Coal Car Lease Payments	(7,010,975)
System Agreement - Supplier Refund	30,000,000
Section 481 Adjustment-263A Decom	22,422,190
Prepaid Expenses	676,489
Contribution Carryover	3,165,995
Units of Property Deduction	68,085,077
Reg Asset - Gustav & Ike	(12,274,284)
Tax Gain/Loss Prop Items	143
EPA Allowances	(143)
License Extension Costs	332,194
Casualty Loss	30,564,927
Abandonment Loss	19,295,408
MISO Cost Deferral	29,769,261
MOARK Cost Deferral	8,665,763
HCM Cost Deferral	22,485,857
Business Development Costs	13,264
Depletion	46,775
ESI Taxes	1,532,162
Rev Proc 2000-50 SW Costs	7,809,646
DOE Litigation	(10,270,697)
Ded for Dividends Paid on Certain Pref Stock	176,530

Total	$415,660,376
	============

Schedule Page: 261 Line No.: 23 Column: a

Reconciling Items:

Federal Income Tax Accrual - Current Year	($25,989,510)
Federal Income Tax - FIN 48	(6,582,409)
Federal Income Tax Accrual - Prior Year	27,298,827
State Income Tax - Prior Year	1,720,937
Provision for Deferred Income Tax - Federal	81,865,187
Provision for Deferred Income Tax - State	6,320,479
Investment Tax Credit - Federal	(1,988,787)
NOL Origination/Utilization	(55,153,664)
ESI Taxes	1,532,162

Total	$29,023,222
	============

Schedule Page: 261 Line No.: 44 Column: a

The Respondent intends to join in the filing of a consolidated Federal Income Tax Return by Entergy Corporation and Subsidiary Companies for the year ended 2013. The estimated consolidated tax allocable under Entergy and Subsidiary Companies Intercompany Income Tax Allocation Agreement based on the provisions of Securities and Exchange Commission Rule 45(c) follows:

Entergy Arkansas, Inc.	($28,493,000)
Entergy Gulf States Louisiana, L.L.C.	(4,400,000)
Entergy Louisiana Holdings, Inc	(1,771,000)
Entergy Mississippi, Inc.	(1,660,000)
Entergy New Orleans, Inc.	(1,322,000)
System Energy Resources, Inc.	(10,086,000)
Entergy Services, Inc.	55,092,000
System Fuels, Inc.	7,000
Entergy Operations, Inc.	9,421,000
Entergy Corporation	(40,487,000)
Entergy Retail Holding Company	(31,000)
Entergy Nuclear Generation Company	(20,070,000)
Entergy Nuclear New York Investment Co I	(37,341,000)
Entergy Nuclear Holding Company #3, LLC	(23,468,000)
Entergy Nuclear Vermont Invest Company, LLC	(31,035,000)
Entergy Power Marketing Holding II, Inc	(985,000)
Entergy Nuclear, Inc.	(565,000)
Entergy Nuclear Holding Company #1	(1,000)
TLG Services, Inc.	(3,000)
Entergy Nuclear Operations, Inc	19,829,000
Entergy Power Holdings, Inc	4,371,000
Entergy Nighthawk GP, LLC	(1,261,000)
Entergy Power International Holdings	45,000
Entergy Mississippi Turbine Company	311,000
Entergy Nuclear Holding Company #2	2,000
EP LLC	(41,000)
Entergy Enterprises, Inc.	(285,000)
Entergy Power Marketing Holding I, Inc.	34,556,000
GSG&T, Inc	2,565,000
Entergy Power Operations U.S., Inc.	342,000
Entergy Nuclear Palisades,Inc	(257,000)
Entergy Amalgamated Competitive Holdings Inc	(1,453,000)
EK Holding III, LLC	1,956,000
Entergy Nuclear Indian Point 1&2 Investmen LLC	64,000
Entergy Texas, Inc	31,290,000
Entergy Holdings Company LLC	107,830,000
Entergy Global LLC	(5,940,000)
Entergy Louisiana, LLC	(40,372,000)
Entergy Louisiana Properties LLC	(5,000)
Arkansas Power & Light Company LLC	98,000
Entergy Technology Holding Company	(80,000)
Entergy Technologies Company	(175,000)
Warren Power, LLC	(1,642,000)
Entergy Asset Management, Inc.	1,548,000
Entergy Investment Holding Company	(8,000)
EWO Wind II, LLC	266,000
Entergy Power Ventures, LLC	30,000

Total	$16,386,000
	============

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	FEDERAL TAXES:					
2	Federal Income Tax	124,161,614		565,646	180,417,000	
3	FICA	1,223,151		9,389,077	8,878,006	
4	Federal Unemployment Tax	-764,874		120,592	144,660	
5	Federal Excise Tax			6,980	6,980	
6	Subtotal	124,619,891		10,082,295	189,446,646	
7						
8	STATE & LOCAL TAXES:					
9	State Income Tax	-25,377,365		9,661,973	4,174,747	
10	State Unemployment Tax	462,789		263,232	250,293	
11	Capital Stock Franchise			1,145,324	1,145,324	
12	Regulatory Commission		1,778,853	3,544,208	3,530,610	
13	Use Tax	2,627,551		20,972,465	20,533,010	
14	Gross Receipts & Sales Tax	1,900		46,093	37,896	
15	Railcar	35,300		99,504	103,504	
16	Gross Receipts Privilege Tax					
17	Ad Valorem Tax	34,857,000		36,710,168	35,483,168	
18	Franchise Tax - Local	6,107,008		38,666,472	39,177,253	
19	State Excise Tax			62,119	62,119	
20	Non Income Tax	987,000		-800,000		
21	Subtotal	19,701,183	1,778,853	110,371,558	104,497,924	
22						
23						
24						
25	Taxes Other Than					
26	Income Taxes					
27	Entergy Services, Inc.					
28						
29						
30	Income Taxes					
31	Entergy Services, Inc.			13,659,163	13,659,163	
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	144,321,074	1,778,853	134,113,016	307,603,733	

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
-55,689,740		1,278,908			-713,262	2
1,734,222		3,213,755			6,175,322	3
-788,942		365			120,227	4
		6,980				5
-54,744,460		4,500,008			5,582,287	6
						7
						8
-19,890,139		7,486,078			2,175,895	9
475,728		108,718			154,514	10
		1,145,324				11
	1,765,255	3,544,208				12
3,067,006		116,731			20,855,734	13
10,097		46,093				14
31,300					99,504	15
						16
36,084,000		32,225,840			4,484,328	17
5,596,227		38,776,813			-110,341	18
		62,119				19
187,000		-800,000				20
25,561,219	1,765,255	82,711,924			27,659,634	21
						22
						23
						24
						25
						26
		10,961,585			-10,961,585	27
						28
						29
						30
		13,659,163				31
						32
						33
						34
						35
						36
						37
						38
						39
						40
-29,183,241	1,765,255	111,832,680			22,280,336	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%	102,967			411.4	23,547	
4	7%						
5	10%	40,844,193			411.4	1,965,240	
6							
7							
8	TOTAL	40,947,160				1,988,787	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
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45							
46							
47							
48							

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
79,420	60 yr		3
			4
38,878,953	60 yr		5
			6
			7
38,958,373			8
			9
			10
			11
			12
			13
			14
			15
			16
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			45
			46
			47
			48

Schedule Page: 266   Line No.: 2   Column: i

Average lives are based on the estimated composite useful life of the properties and are subject to reconsideration each year.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Unfunded Pension Expense	489,358,580	131,182.3	205,764,249	12,750,686	296,345,017
2						
3	Supplemental Pension Plan	4,114,212	*	457,272	137,893	3,794,833
4						
5	Book Gain on Sale/Leaseback					
6	ANO Support Buildings - Amort					
7	Period 30 years/term of lease	280,330	525	82,048		198,282
8						
9	Long-term Incentive Plan	39,059			69,446	108,505
10						
11	Disallowed costs - EAI Rate Case					
12	Settlement - Docket 09-84-U	11,770,844	Various	9,099,813	16,473,455	19,144,486
13						
14	KGEN Asset					
15	Purchase Agreement	26,000,000	242	13,800,000		12,200,000
16						
17	Non IPP Advances and Tax					
18	Gross Up	6,159,745	**	3,849,721	8,028,886	10,338,910
19						
20	FERC/NERC penalty accrual	403,148	131	480,868	112,213	34,493
21						
22	Other	67,976	107,926	67,976	11,163	11,163
23						
24						
25	* 131, 182.3, 232, 241, 242					
26	** 107, 143, 234, 421					
27						
28						
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38						
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41						
42						
43						
44						
45						
46						
47	TOTAL	538,193,894		233,601,947	37,583,742	342,175,689

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	1,596,621,901	425,638,569	382,356,216
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	1,596,621,901	425,638,569	382,356,216
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	1,596,621,901	425,638,569	382,356,216
10	Classification of TOTAL			
11	Federal Income Tax	1,372,876,338	367,849,126	327,973,967
12	State Income Tax	223,745,563	57,789,443	54,382,249
13	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
		182.3	4,411,263			1,635,492,991	2
							3
							4
			4,411,263			1,635,492,991	5
							6
							7
							8
			4,411,263			1,635,492,991	9
							10
		182.3	3,618,593			1,409,132,904	11
		182.3	792,670			226,360,087	12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	See Detail	932,032,629	74,968,140	28,681,039
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	932,032,629	74,968,140	28,681,039
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18				
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	932,032,629	74,968,140	28,681,039
20	Classification of TOTAL			
21	Federal Income Tax	856,257,583	65,119,981	25,026,523
22	State Income Tax	75,775,046	9,848,159	3,654,516
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
		1823/283	144,458,450	283	18,530,173	852,391,453	3
							4
							5
							6
							7
							8
			144,458,450		18,530,173	852,391,453	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
			144,458,450		18,530,173	852,391,453	19
							20
		1823/283	120,520,147	283	15,459,525	791,290,419	21
		1823/283	23,938,303	283	3,070,648	61,101,034	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 3 Column: a

	Balance at Beg of Year	Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
Regulatory Asset Securitization	$36,852,032	$25,045,505	$11,293,597
Regulatory Asset - MISO	-	6,150,194	337,149
System Equalization Agreement	(1)	12,450,000	682,500
Maint./Refueling Reserve	15,066,385	6,383,085	9,236,920
Minimum Pension Liability	313,834,604	-	-
Bond Reacquisition Loss	12,355,471	185,152	1,229,768
Section 475 Adjustment	(93,682)	7,721,141	574,660
Capitalized Costs	8,037,121	-	-
Regulatory Asset - HCM	-	-	-
Regulatory Asset - MOARK	-	-	-
TCBY Tower (CADC)	13,687,209	152,099	1,404,746
Misc Capitalized Costs	6,136,067	5,760,572	1,785,402
Regulatory Asset - 30 Yr Retail	3,925,045	11,981	218,563
Prepaid Expenses	2,011,485	296,057	16,230
263A Method Change-283901	142,427,810	3,243,707	570,450
263A Method Change-283F48	332,331,556	7,568,647	1,331,054
Inc tax Adjustment	45,461,527	-	-
	$932,032,629	$74,968,140	$28,681,039

	Adjustments Debits Acct No	Debits Amount	Credits Acct No	Credits Amount	Balance at End of Year
Regulatory Asset Securitization	283	$13,481,947		$-	$37,121,993
Regulatory Asset - MISO		-	283	6,310,950	12,123,995
System Equalization Agreement		-		-	11,767,499
Maint./Refueling Reserve		-		-	12,212,550
Minimum Pension Liability	182.3	123,081,188		-	190,753,416
Bond Reacquisition Loss		-		-	11,310,855
Section 475 Adjustment		-		-	7,052,799
Capitalized Costs		-		-	8,037,121
Regulatory Asset - HCM		-	283	8,820,077	8,820,077
Regulatory Asset - MOARK		-	283	3,399,146	3,399,146
TCBY Tower (CADC)		-		-	12,434,562
Misc Capitalized Costs	283	5,048,226		-	5,063,011
Regulatory Asset - 30 Yr Retail		-		-	3,718,463
Prepaid Expenses		-		-	2,291,312
263A Method Change		-		-	145,101,067
263A Method Change		-		-	338,569,149
Inc tax Adjustment	182.3	2,847,089		-	42,614,438
		$144,458,450		$18,530,173	$852,391,453

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Certain Investments in Debt & Equity Securities:					
2	ANO 1 Qualified Fund - Valuation Acct	70,757,500	128	20,628,271	67,402,850	117,532,079
3	ANO 2 Qualified Fund - Valuation Acct	59,692,151	128	14,261,468	51,136,759	96,567,442
4						
5	Income Taxes	35,148,626	190	1,176,624	805,220	34,777,222
6						
7	Capacity Rider - Over recovery	1,203,876	407.4	550,112	4,063,694	4,717,458
8						
9	Deferred Fuel Over-Recovery	29,912,684	557,431	29,912,684		
10						
11	DOE Spent Nuclear Fuel Storage Cost Settlement				553,171	553,171
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	196,714,837		66,529,159	123,961,694	254,147,372

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	764,681,554	758,155,930
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	465,304,811	467,676,038
5	Large (or Ind.) (See Instr. 4)	429,603,036	436,000,696
6	(444) Public Street and Highway Lighting	9,264,512	9,200,362
7	(445) Other Sales to Public Authorities	9,832,959	10,472,510
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,678,686,872	1,681,505,536
11	(447) Sales for Resale	429,141,267	369,322,249
12	TOTAL Sales of Electricity	2,107,828,139	2,050,827,785
13	(Less) (449.1) Provision for Rate Refunds	576,368	-144,601
14	TOTAL Revenues Net of Prov. for Refunds	2,107,251,771	2,050,972,386
15	Other Operating Revenues		
16	(450) Forfeited Discounts	10,119,926	9,713,931
17	(451) Miscellaneous Service Revenues	2,721,108	2,844,260
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	5,803,874	5,877,581
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	16,045,699	9,165,978
22	(456.1) Revenues from Transmission of Electricity of Others	33,613,480	33,153,729
23	(457.1) Regional Control Service Revenues	50,158	
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	68,354,245	60,755,479
27	TOTAL Electric Operating Revenues	2,175,606,016	2,111,727,865

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
7,921,078	7,858,973	585,378	584,560	2
				3
5,928,538	6,045,688	90,045	89,371	4
6,768,840	6,925,238	23,001	22,580	5
77,166	77,888	635	634	6
163,540	179,083	48	49	7
				8
				9
20,859,162	21,086,870	699,107	697,194	10
8,929,794	9,019,385	13	12	11
29,788,956	30,106,255	699,120	697,206	12
				13
29,788,956	30,106,255	699,120	697,206	14

Line 12, column (b) includes $ 0 of unbilled revenues.

Line 12, column (d) includes 0 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 4 Column: b

Basis of classification of Commercial and Industrial Sales Account 442: (a) Industrial - Standard Classification Manual; (b) Commercial - all other business or professional activities of a non-manufacturing nature.

Schedule Page: 300 Line No.: 4 Column: c

Basis of classification of Commercial and Industrial Sales Account 442: (a) Industrial - Standard Classification Manual; (b) Commercial - all other business or professional activities of a non-manufacturing nature.

Schedule Page: 300 Line No.: 21 Column: b

Other Electric Revenue includes:

Unbilled Revenues	$9,396,558*
Transmission Equalization Revenues	2,965,910
Distribution Substation Svc.	2,413,993
AR Gross Receipts Tax	652,892
Affiliate Service Fee Revenue	245,000
Little Rock Air Force Base	188,935
Miscellanous Revenue	94,829
MISO Mkt Sch 11 Wholesale Distribution Revenue	87,582
Total	$16,045,699

*Includes 99,804 MWH

Schedule Page: 300 Line No.: 21 Column: c

Other Electric Revenue includes:

Unbilled Revenues	$2,186,629*
Affiliate Service Fee Revenue	82,500
Arkansas Gross Receipts Tax	622,526
Distribution Substation Svc.	2,572,650
Transmission Equalization Revenues	3,342,865
Little Rock Air Force Base	358,808
Total	$9,165,978

*Includes 12,963 MWH

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	MISO Sch1 System Control & Dispatch				50,158
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				50,158

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RESIDENTIAL					
2	RS Gen. Purpose Res.	7,833,437	461,207,249	582,467	13,449	0.0589
3	RS3 Gen. Purpose Res.	7,620	446,564	428	17,804	0.0586
4	RT Opt. Res. Time-of-Use	679	41,226	51	13,314	0.0607
5	RW Gen. Purpose Res.	183	6,378	1	183,000	0.0349
6	RMT Res Energy Mgmt TOU	305	17,952	21	14,524	0.0589
7	L4 All Night Outdoor Lighting	78,086	8,135,293	2,331	33,499	0.1042
8	M33 Rate Rider		71,896,206			
9	ECR Energy Cost Recovery Rider		113,608,407			
10	PCA Production Costs Allocation R		48,106,285			
11	EECR Energy Efficiency Cost Rate		21,427,379			
12	CA Capacity Acquisition Rider		11,904,341			
13	MFA Municipal Franchise Adj		19,742,836			
14	GMES Gov't Mandated Exp Srchg		1,872,251			
15	FLCF Federal Litig Consult Fee		221,703			
16	ANOR ANO1 Interim Capacity Cost		5,995,982			
17	Misc	768	51,502	79	9,722	0.0671
18	TOTAL RESIDENTIAL	7,921,078	764,681,554	585,378	13,532	0.0965
19						
20						
21						
22						
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26						
27						
28						
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39						
40						
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	COMMERCIAL					
2	SG1 Small Gen. Service	3,103,485	164,070,709	83,232	37,287	0.0529
3	SG2 Small Gen. Service	16,633	853,221	25	665,320	0.0513
4	SG3 Small Gen. Service	609	28,563	7	87,000	0.0469
5	SG4 Small Gen. Service	17,811	773,941	29	614,172	0.0435
6	SG7 Small Gen. Service	12,791	667,905	781	16,378	0.0522
7	GT1 Opt. LGS Time-of-Use	696,273	22,604,238	354	1,966,873	0.0325
8	GT2 Opt. LGS Time-of-Use	42,373	1,333,448	6	7,062,167	0.0315
9	GT4 Opt. LGS Time-of-Use	32,345	970,245	10	3,234,500	0.0300
10	IG1 LGS TOU Interruptible	9,880	159,368	2	4,940,000	0.0161
11	IG4 LGS TOU Interruptible	196,728	2,860,738	3	65,576,000	0.0145
12	LG1 Large Gen. Service	1,082,636	41,412,844	1,022	1,059,331	0.0383
13	LG2 Large Gen. Service	26,719	1,013,493	13	2,055,308	0.0379
14	LG4 Large Gen. Service	27,829	1,003,576	13	2,140,692	0.0361
15	IL1 LGS Interruptible	4,452	89,103	4	1,113,000	0.0200
16	LP1 Large Power Service	29,562	1,031,999	4	7,390,500	0.0349
17	LP2 Large Power Service	9,246	393,069	2	4,623,000	0.0425
18	LP4 Large Power Service	54,291	1,827,280	4	13,572,750	0.0337
19	PT1 Opt. LPS Time-of-Use	82,230	2,411,643	8	10,278,750	0.0293
20	PT2 Opt. LPS Time-of-Use	140,073	4,247,816	8	17,509,125	0.0303
21	PT4 Opt. LPS Time-of-Use	200,134	6,008,875	7	28,590,571	0.0300
22	IT4 LPS Time-of-Use Interruptib	14,918	222,749	1	14,918,000	0.0149
23	CTV Comm. Ant. & TV Amp.	25,325	1,425,408	2,591	9,774	0.0563
24	L4 All Night Outdoor Lighting	100,045	7,781,500	1,878	53,272	0.0778
25	M33 Rate Rider		39,174,791			
26	ECR Energy Cost Recovery Rider		83,642,068			
27	TCA Transition Cost Adjustment Ri		2			
28	PCA Production Costs Allocation R		34,837,351			
29	EECR Energy Efficiency Cost Rate		13,471,301			
30	CA Capacity Acquisition Rider		8,596,759			
31	SDR Storm Damage Rider		-135			
32	MFA Municipal Franchise Adj		17,044,348			
33	GMES Gov't Mandated Exp Srchg		1,107,711			
34	FLCF Federal Litig Consult Fee		158,959			
35	ANO ANO1 Interim Capacity Cost Re		3,974,689			
36	Misc	2,150	105,236	41	52,439	0.0489
37	TOTAL COMMERCIAL	5,928,538	465,304,811	90,045	65,840	0.0785
38						
39						
40						
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

Name of Respondent Entergy Arkansas, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	INDUSTRIAL					
2	FA General Farm Service	84,022	4,093,537	4,288	19,595	0.0487
3	FAC General Farm Service	56,542	3,580,636	1,224	46,194	0.0633
4	SG1 Small Gen. Service	660,768	36,001,123	10,197	64,800	0.0545
5	SG2 Small Gen. Service	72,666	3,746,213	52	1,397,423	0.0516
6	SG3 Small Gen. Service	5,039	215,640	27	186,630	0.0428
7	SG4 Small Gen. Service	88,675	3,575,599	48	1,847,396	0.0403
8	SG5 Small Gen. Service	40,699	3,340,881	6	6,783,167	0.0821
9	SG6 Small Gen. Service	603	142,592	1	603,000	0.2365
10	IS2 SGS Interruptible	627	24,870	1	627,000	0.0397
11	IS4 SGS Interruptible	16,251	719,066	2	8,125,500	0.0442
12	GT1 Opt. LGS Time-of-Use	251,983	8,139,503	103	2,446,437	0.0323
13	GT2 Opt. LGS Time-of-Use	25,704	973,819	5	5,140,800	0.0379
14	GT4 Opt. LGS Time-of-Use	187,368	5,021,828	48	3,903,500	0.0268
15	IG1 LGS TOU Interruptible	50,426	928,022	7	7,203,714	0.0184
16	IG2 LGS TOU Interruptible	6,958	117,225	1	6,958,000	0.0168
17	IG3 LGS TOU Interruptible	5,713	101,306	1	5,713,000	0.0177
18	IG4 LGS TOU Interruptible	5,239	89,646	1	5,239,000	0.0171
19	LG1 Large Gen. Service	467,557	18,381,677	267	1,751,150	0.0393
20	LG2 Large Gen. Service	42,745	1,787,610	19	2,249,737	0.0418
21	LG3 Large Gen. Service	221	7,893	1	221,000	0.0357
22	LG4 Large Gen. Service	63,466	2,487,673	17	3,733,294	0.0392
23	LG5 Large Gen. Service	15,250	501,965	4	3,812,500	0.0329
24	IL1 LGS Interruptible	23,475	514,353	9	2,608,333	0.0219
25	IL2 LGS Interruptible	20,748	503,810	2	10,374,000	0.0243
26	LP1 Large Power Service	34,693	1,479,908	6	5,782,167	0.0427
27	LP2 Large Power Service	175,223	6,419,152	14	12,515,929	0.0366
28	LP4 Large Power Service	267,607	9,571,718	18	14,867,056	0.0358
29	IP2 LPS Interruptible	24,038	635,347	1	24,038,000	0.0264
30	PT1 Opt. LPS Time-of-Use	189,158	6,098,849	17	11,126,941	0.0322
31	PT2 Opt. LPS Time-of-Use	457,157	15,034,501	20	22,857,850	0.0329
32	PT4 Opt. LPS Time-of-Use	1,834,839	50,509,385	47	39,039,128	0.0275
33	PT5 Opt. LPS Time-of-Use	30,993	1,561,775	5	6,198,600	0.0504
34	PT6 Opt. LPS Time-of-Use	32,382	1,101,086	2	16,191,000	0.0340
35	IT1 LPS TOU Interruptible	18,138	387,780	2	9,069,000	0.0214
36	IT4 LPS TOU Interruptible	799,067	17,995,330	5	159,813,400	0.0225
37	IT6 LPS TOU Interruptible	358,316	5,939,740	2	179,158,000	0.0166
38	APA Irrigation Service	208,271	12,193,340	4,245	49,063	0.0585
39	APB Irrigation Service	45,336	3,374,168	2,035	22,278	0.0744
40	CGS Cotton Ginning Service	21,971	1,281,820	35	627,743	0.0583
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	L4 All Night Outdoor Lighting	14,500	1,093,027	211	68,720	0.0754
2	SS Standby Service	64,406	3,586,237			0.0557
3	C23 Cogeneration		1,006	5		
4	M26 Rate Rider					
5	M33 Rate Rider		34,224,665			
6	ECR Energy Cost Recovery Rider		94,847,369			
7	PCA Production Costs Allocation R		39,961,995			
8	EECR Energy Efficiency Cost Rate		11,800,532			
9	CA Capacity Acquisition Rider		8,685,486			
10	MFA Municipal Franchise Adj		1,968,904			
11	GMES Gov't Mandated Exp Srchg		991,879			
12	FLCF Federal Litig Consult Fee		180,722			
13	ANOR ANO1 Interim Capacity Cost		3,680,828			
14	TOTAL INDUSTRIAL	6,768,840	429,603,036	23,001	294,285	0.0635
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	PUBLIC STREET & HWY LIGHT.					
2	L1 Municipal Street Lighting	70,809	6,090,279	306	231,402	0.0860
3	L1SH Municipal Shielded Street Li	93	11,655	3	31,000	0.1253
4	L2 Traffic Signal Service	5,934	358,216	267	22,225	0.0604
5	L4 All Night Outdoor Lighting	330	27,177	59	5,593	0.0824
6	M33 Rate Rider		960,046			
7	ECR Energy Cost Recovery Rider		1,101,000			
8	PCA Production Costs Allocation R		454,882			
9	EECR Energy Efficiency Cost Rate		116,574			
10	CA Capacity Acquisition Rider		69,239			
11	MFA Municipal Franchise Adj		13,544			
12	GMES Gov't Mandated Exp Srchg		27,819			
13	FLCF Federal Litig Consult Fee		2,141			
14	ANOR ANO1 Interim Capacity Cost		31,940			
15	TOTAL PUBLIC STREET & HWY	77,166	9,264,512	635	121,521	0.1201
16						
17						
18						
19						
20	OTHER SALES TO					
21	PUBLIC AUTHORITIES					
22	SG1 Small Gen. Service	1,049	53,286	17	61,706	0.0508
23	LP4 Large Power Service	22,663	818,579	1	22,663,000	0.0361
24	LP5 Large Power Service	11,267	418,047	1	11,267,000	0.0371
25	PT2 Opt. LPS Time-of-Use	96,685	2,854,972	1	96,685,000	0.0295
26	PT4 Opt. LPS Time-of-Use	30,979	943,867	1	30,979,000	0.0305
27	L4 All Night Outdoor Lighting	29	2,708	5	5,800	0.0934
28	MP Municipal Pump Service	718	35,420	21	34,190	0.0493
29	M33 Rate Rider		746,184			
30	ECR Energy Cost Recovery Rider		2,284,669			
31	PCA Production Costs Allocation R		973,634			
32	EECR Energy Efficiency Cost Rate		366,000			
33	CA Capacity Acquisition Rider		209,334			
34	MFA Municipal Franchise Adj		2,835			
35	GMES Gov't Mandated Exp Srchg		20,841			
36	FLCF Federal Litig Consult Fee		4,351			
37	ANOR ANO1 Interim Capacity Cost		94,641			
38	Misc	150	3,591	1	150,000	0.0239
39	TOTAL OTHER SALES	163,540	9,832,959	48	3,407,083	0.0601
40						
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Entergy System Power Pool	OS	94	N/A	N/A	N/A
2	System Sales to Others	OS	94	N/A	N/A	N/A
3	Entergy Louisiana, LLC (1)	LU		N/A	N/A	N/A
4	Entergy Mississippi, Inc. (1)	IU		N/A	N/A	N/A
5	Entergy New Orleans, Inc. (1)	LU		N/A	N/A	N/A
6	Entergy Gulf States LA, LLC (1)	IU		N/A	N/A	N/A
7	Entergy Texas, Inc. (1)	IU		N/A	N/A	N/A
8	Entergy Power, LLC (2)	OS	123	N/A	N/A	N/A
9	Conway Corporation (2)	OS	98	N/A	N/A	N/A
10	Jonesboro City Light & Water (2)	OS	151	N/A	N/A	N/A
11	City of Osceola (2)	OS	101	N/A	N/A	N/A
12	City of West Memphis (2)	OS	99	N/A	N/A	N/A
13	Arkansas Electric Cooperative Corp. (2)	OS	82	1959	1781	1781
14	East Texas Electric Cooperative (2)	OS	147	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Entergy Mississippi, Inc. (2)	OS		N/A	N/A	N/A
2	Associated Electric Coop., Inc.	RQ	130	0	0	0
3	Midcontinent ISO, Inc.	OS		N/A	N/A	N/A
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
4,416,485	1,670,721	154,675,031		156,345,752	1
22,020		327,194	120,241	447,435	2
768,289	31,016,776	10,386,002		41,402,778	3
680,373	45,772,478	7,186,937		52,959,415	4
768,055	30,963,585	10,377,096		41,340,681	5
18	102,567	780		103,347	6
1,249,088	27,782,138	20,793,030		48,575,168	7
36,108		2,163,691		2,163,691	8
54,753		3,118,024		3,118,024	9
22,888		3,094,095		3,094,095	10
6,551		432,726		432,726	11
27,039		1,556,218		1,556,218	12
623,974		29,804,975	34,643,388	64,448,363	13
103,119		4,093,251		4,093,251	14
261	3,705	11,704	0	15,409	
8,929,533	137,308,265	257,053,964	34,763,629	429,125,858	
8,929,794	**137,311,970**	**257,065,668**	**34,763,629**	**429,141,267**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
		3,465,761		3,465,761	1
261	3,705	11,704		15,409	2
150,773		5,579,153		5,579,153	3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
261	3,705	11,704	0	15,409	
8,929,533	137,308,265	257,053,964	34,763,629	429,125,858	
8,929,794	**137,311,970**	**257,065,668**	**34,763,629**	**429,141,267**	

Schedule Page: 310 Line No.: 1 Column: a

A contract wherein the parties have combined their power sources and transmission facilities on a pool basis to maximize overall capability, reliability, and economy.

Schedule Page: 310 Line No.: 2 Column: a

System Sales to Others Year Ended 12/31/2013

	MWH	Charges
Ameren Energy Marketing Company	702	$22,380
American Electric Power	1,919	107,367
Arkansas Electric Cooperative Corp.	1,608	69,155
Associated Electric Cooperative, Inc.	5,262	138,190
Board of Public Utilities	352	22,307
Cargill Power Markets LLC	1,955	75,818
Carroll St. Park	1	77
Central Louisiana Electric Company	2,185	125,597
Citigroup Energy, Inc.	3,524	113,842
City of Caldwell	17	1,177
City of Lafayette	123	5,914
City of Thayer	158	10,251
City Utilities of Springfield	108	6,042
Constellation Energy Comm Group, Inc.	748	28,867
Empire District Electric	218	13,568
ETC Endure Energy L.L.C.	5,947	165,299
EWOM	1,632	123,182
Exelon Generation Company LLC	1,109	42,341
Exxon ENCO	11	931
Grand River Dam Authority	1,108	67,230
Independence Power and Light Co.	18	1,404
Kansas City Power & Light	2,544	140,690
Lincoln	428	24,037
Louisiana Energy Power Authority	38	2,028
Magnet Cove	605	31,166
Mississippi Delta Energy Agency	3,571	250,092
Nebraska Public Power District	488	26,036
NRG Power Marketing LLC	802	22,393
Occidental Chemical Corp.	190	9,161
Oklahoma Gas & Electric	1,927	114,267
Omaha Public Power District	568	27,264
Pine Bluff Energy	61	4,421
RS Cogen, LLC	329	17,805
Sabine Cogen, L.P.	21	1,102
Southern Company Services, Inc.	91,585	1,756,363
Southern Miss Electric Power Assoc	494	38,821
Southwestern Public Service	306	16,235
SRW Cogen, L.P.	349	19,853
Sunflower Electric Company	375	20,885
Tenaska	4,453	113,560
Tenaska Frontier	2,770	156,720
Tennessee Valley Authority	32,352	1,211,893
The Energy Authority	2,037	59,930
Union Carbide Corp.	6	412
Union Electric D/B/A Ameren Missouri	3,523	55,172
Union Power Partners, L.P.	150	4,950
Westar Energy	8,406	301,897

Western Area Power Administration	1,181	64,628
Western Farmers Electric Coop.	67	3,429
Wrightsville Power	1,691	101,786
	---------	------------
	190,022	5,737,935
Plus: Net Adjustments to Sales	(6,050)	44,842
	---------	------------
	183,972	$5,782,777
	=========	============

TOTAL SYSTEM SALES TO OTHERS:

Supplied By:	MWH	REVENUE
Entergy Arkansas, Inc.	22,020	$447,435
Entergy Gulf States Louisiana, LLC	19,227	386,567
Entergy Texas, Inc.	76,341	3,456,627
Entergy Louisiana, LLC	46,803	1,102,899
Entergy Mississippi, Inc.	14,782	293,241
Entergy New Orleans, Inc.	4,799	96,008
	---------	------------
	183,972	$5,782,777
	=========	============

Note:

The Entergy Companies jointly supply energy for sales to non-associated utilities. Due to the format of purchased power accounting records, it is impractical to identify precisely how much each system company supplied to any given sale.

(a) Amount in other charges represents imputed transmission.

(b) Generator Imbalance Agreement (GIA) Sales are sales made pursuant to the GIA for under delivery of energy.

Schedule Page: 310 Line No.: 3 Column: a

(1) Energy and capacity sales associated with the Resource Plan.

Schedule Page: 310 Line No.: 8 Column: a

(2) Includes revenue from co-owners of White Bluff, Independence, and Ritchie Steam Electric Stations due to heat rate incentive and supplying entitlement energy from units other than jointly owned units.

Schedule Page: 310.1 Line No.: 2 Column: a

Sales provided under a letter agreement effective March 1992.

Schedule Page: 310.1 Line No.: 4 Column: a

Amounts shown in column (h) are Production Demand related revenues. Amounts in column (j) are Transmission Demand, Distribution Demand, or other charges related to revenues.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	6,354,902	7,125,003
5	(501) Fuel	321,067,144	241,672,492
6	(502) Steam Expenses	2,698,332	2,688,134
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,767,794	1,749,106
10	(506) Miscellaneous Steam Power Expenses	5,860,038	5,520,584
11	(507) Rents	304,895	261,649
12	(509) Allowances	90,147	56,215
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	338,143,252	259,073,183
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	957,318	1,024,518
16	(511) Maintenance of Structures	1,875,311	1,053,188
17	(512) Maintenance of Boiler Plant	13,944,944	13,931,012
18	(513) Maintenance of Electric Plant	6,224,125	4,347,036
19	(514) Maintenance of Miscellaneous Steam Plant	2,384,223	2,756,238
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	25,385,921	23,111,992
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	363,529,173	282,185,175
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	25,832,697	23,911,306
25	(518) Fuel	75,757,279	125,110,289
26	(519) Coolants and Water	5,356,758	4,969,582
27	(520) Steam Expenses	33,353,747	34,936,766
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses	30,214,246	30,375,178
32	(525) Rents	4,354,780	3,648,717
33	TOTAL Operation (Enter Total of lines 24 thru 32)	174,869,507	222,951,838
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	17,986,116	19,820,273
36	(529) Maintenance of Structures	568,410	1,199,481
37	(530) Maintenance of Reactor Plant Equipment	11,154,470	8,796,443
38	(531) Maintenance of Electric Plant	8,694,750	7,448,322
39	(532) Maintenance of Miscellaneous Nuclear Plant	59,730,133	62,351,096
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	98,133,879	99,615,615
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	273,003,386	322,567,453
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	296,485	254,338
45	(536) Water for Power	202,410	249,718
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses	35,692	34,146
48	(539) Miscellaneous Hydraulic Power Generation Expenses	314,308	266,074
49	(540) Rents	25,543	26,259
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	874,438	830,535
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	8,285	965
54	(542) Maintenance of Structures	92,690	87,780
55	(543) Maintenance of Reservoirs, Dams, and Waterways	420,972	600,525
56	(544) Maintenance of Electric Plant	164,033	442,556
57	(545) Maintenance of Miscellaneous Hydraulic Plant	172,932	294,519
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	858,912	1,426,345
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	1,733,350	2,256,880

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,984,746	1,693,648
63	(547) Fuel	445,963	225,919
64	(548) Generation Expenses	1,209,039	519,617
65	(549) Miscellaneous Other Power Generation Expenses	3,708,470	1,723,457
66	(550) Rents	86,697	43,805
67	TOTAL Operation (Enter Total of lines 62 thru 66)	7,434,915	4,206,446
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	835,113	286,536
70	(552) Maintenance of Structures	184,981	260,201
71	(553) Maintenance of Generating and Electric Plant	16,895,316	5,187,873
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	290,094	195,033
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	18,205,504	5,929,643
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	25,640,419	10,136,089
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	473,324,174	431,931,642
77	(556) System Control and Load Dispatching	1,049,064	1,004,504
78	(557) Other Expenses	29,221,664	113,710,381
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	503,594,902	546,646,527
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,167,501,230	1,163,792,124
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	7,982,781	8,927,400
84			
85	(561.1) Load Dispatch-Reliability	301,999	303,523
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,202,986	2,123,182
87	(561.3) Load Dispatch-Transmission Service and Scheduling	794,652	646,325
88	(561.4) Scheduling, System Control and Dispatch Services	142,124	
89	(561.5) Reliability, Planning and Standards Development	489,378	440,784
90	(561.6) Transmission Service Studies	50,206	59,563
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	381,159	373,204
94	(563) Overhead Lines Expenses	694,041	497,614
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	1,520,489	618,141
97	(566) Miscellaneous Transmission Expenses	4,204,455	3,481,953
98	(567) Rents	138,535	1,152,257
99	TOTAL Operation (Enter Total of lines 83 thru 98)	18,902,805	18,623,946
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	5,423,363	5,777,461
102	(569) Maintenance of Structures	213,809	166,056
103	(569.1) Maintenance of Computer Hardware	54,325	137,267
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,438,353	2,532,969
108	(571) Maintenance of Overhead Lines	3,055,568	1,352,530
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	127,249	29,682
111	TOTAL Maintenance (Total of lines 101 thru 110)	11,312,667	9,995,965
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	30,215,472	28,619,911

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation	165,282	178,872
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	137,198	
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	302,480	178,872
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		100,061
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		100,061
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	302,480	278,933
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	10,158,372	9,793,013
135	(581) Load Dispatching	724,065	674,719
136	(582) Station Expenses	421,556	425,798
137	(583) Overhead Line Expenses	1,511,206	1,675,341
138	(584) Underground Line Expenses	1,583,729	1,546,356
139	(585) Street Lighting and Signal System Expenses	94,618	89,302
140	(586) Meter Expenses	4,912,696	4,954,307
141	(587) Customer Installations Expenses	1,063,728	1,001,292
142	(588) Miscellaneous Expenses	2,999,738	2,264,823
143	(589) Rents	2,048,426	2,197,273
144	TOTAL Operation (Enter Total of lines 134 thru 143)	25,518,134	24,622,224
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	3,036,919	2,289,175
147	(591) Maintenance of Structures	915,567	137,648
148	(592) Maintenance of Station Equipment	2,723,677	3,229,502
149	(593) Maintenance of Overhead Lines	21,733,931	20,607,368
150	(594) Maintenance of Underground Lines	1,385,522	1,702,175
151	(595) Maintenance of Line Transformers	67,788	32,918
152	(596) Maintenance of Street Lighting and Signal Systems	2,227,312	2,208,308
153	(597) Maintenance of Meters	136,150	148,624
154	(598) Maintenance of Miscellaneous Distribution Plant	1,322,458	1,037,030
155	TOTAL Maintenance (Total of lines 146 thru 154)	33,549,324	31,392,748
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	59,067,458	56,014,972
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	396,101	481,958
160	(902) Meter Reading Expenses	6,703,221	6,456,884
161	(903) Customer Records and Collection Expenses	24,536,212	23,944,677
162	(904) Uncollectible Accounts	6,811,216	6,362,107
163	(905) Miscellaneous Customer Accounts Expenses	14,190	18,476
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	38,460,940	37,264,102

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	243,566	457,292
168	(908) Customer Assistance Expenses	39,279,902	24,791,292
169	(909) Informational and Instructional Expenses	1,152,853	1,107,317
170	(910) Miscellaneous Customer Service and Informational Expenses	1,176,665	967,709
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	41,852,986	27,323,610
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	33,898	28,317
175	(912) Demonstrating and Selling Expenses	30,965	89,446
176	(913) Advertising Expenses	75,621	73,987
177	(916) Miscellaneous Sales Expenses	454,566	878,438
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	595,050	1,070,188
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	34,218,599	29,239,472
182	(921) Office Supplies and Expenses	3,638,454	3,923,587
183	(Less) (922) Administrative Expenses Transferred-Credit	5,648,469	5,415,572
184	(923) Outside Services Employed	21,747,148	29,928,027
185	(924) Property Insurance	22,009,001	21,398,218
186	(925) Injuries and Damages	4,736,174	4,997,642
187	(926) Employee Pensions and Benefits	97,464,508	91,374,953
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	3,986,150	3,648,857
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	140,282	108,644
192	(930.2) Miscellaneous General Expenses	523,186	691,078
193	(931) Rents	5,018,501	5,282,099
194	TOTAL Operation (Enter Total of lines 181 thru 193)	187,833,534	185,177,005
195	Maintenance		
196	(935) Maintenance of General Plant	2,214,869	3,641,493
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	190,048,403	188,818,498
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,528,044,019	1,503,182,338

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	ASSOCIATED UTILITIES					
2	Entergy System Power Pool	OS		N/A	N/A	N/A
3	System Energy Resources, Inc.	OS		N/A	N/A	N/A
4	Entergy Power Marketing Corp.	OS		N/A	N/A	N/A
5	EWO Marketing, LLC (1)	OS	OATT	N/A	N/A	N/A
6	NON-ASSOCIATED UTILITIES					
7	System Purchases from Others	OS		N/A	N/A	N/A
8	Midcontinent ISO, Inc.	OS		N/A	N/A	N/A
9	Mississippi Delta Energy Agency (1)	OS	OATT	N/A	N/A	N/A
10	City of Caldwell (1)	OS	OATT	N/A	N/A	N/A
11	City of Kirbyville (1)	OS	OATT	N/A	N/A	N/A
12	City of Newton (1)	OS	OATT	N/A	N/A	N/A
13	City of Thayer (1)	OS	OATT	N/A	N/A	N/A
14						
	Total					

Name of Respondent Entergy Arkansas, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	OTHER NON-UTILITIES					
2	Arkansas Electric Coop Corp	OS	82	N/A	N/A	N/A
3	City Water & Light	OS	94	N/A	N/A	N/A
4	Conway	OS	98	N/A	N/A	N/A
5	Cross Oil (2)	OS	**	N/A	N/A	N/A
6	East Texas Electric Cooperative	OS	147	N/A	N/A	N/A
7	North Little Rock Electric Dept	OS		N/A	N/A	N/A
8	Little Rock Wastewater	OS	M23	N/A	N/A	N/A
9	Osceola	OS	101	N/A	N/A	N/A
10	Pine Bluff Energy (2)	OS	**	N/A	N/A	N/A
11	Potlatch Forest	OS	M23	N/A	N/A	N/A
12	West Memphis	OS	99	N/A	N/A	N/A
13	West Fraiser	OS	M23	N/A	N/A	N/A
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
							1
491,548			18,197,509	25,154,492		43,352,001	2
3,525,681			236,825,515	37,208,937	-12,173,877	261,860,575	3
197,264				6,153,373		6,153,373	4
73,606				3,952,922		3,952,922	5
							6
1,862,087	323,443	225,052	617,842	73,426,644		74,044,486	7
43,725				2,896,553	24,526	2,921,079	8
1,517				92,431		92,431	9
19,423				1,171,957		1,171,957	10
19,739				1,197,798		1,197,798	11
20,583				1,242,190		1,242,190	12
3,228				214,441		214,441	13
							14
8,624,898	323,443	225,052	255,833,984	229,639,541	-12,149,351	473,324,174	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
685,998				22,089,019		22,089,019	2
334,454				11,037,579		11,037,579	3
36,447				1,091,942		1,091,942	4
2,196				73,412		73,412	5
301				9,266		9,266	6
270				21,541		21,541	7
688				23,850		23,850	8
7,002				209,355		209,355	9
1,257,757				41,019,023		41,019,023	10
18,603				611,828		611,828	11
22,602			193,118	735,076		928,194	12
179				5,912		5,912	13
							14
8,624,898	323,443	225,052	255,833,984	229,639,541	-12,149,351	473,324,174	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) X An Original (2) _ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 326 Line No.: 2 Column: a

Represents charges from other member companies of the Entergy System under an interconnection agreement and contract, wherein the parties have combined their power sources and transmission facilities for maximum overall capacity, reliability, and economy.

Schedule Page: 326 Line No.: 3 Column: a

Energy and capacity charges from Grand Gulf Nuclear Power Plant.

Schedule Page: 326 Line No.: 3 Column: l

Represents ($6,235,635) for deferral on over/under recovery under the Grand Gulf Rider and the turnaround of the Grand Gulf Accelerated Recovery Tariff approved by the FERC that provided for the acceleration of Entergy Arkansas Inc's and Entergy Mississippi Inc's Grand Gulf purchased power obligations with System Energy Resources, Inc. and ($5,938,242) related to GGART.

Schedule Page: 326 Line No.: 4 Column: a

Purchase of entitlement energy in excess of co-owner requirements in accordance with the respective Purchased Power Agreements.

Schedule Page: 326 Line No.: 5 Column: a

(1) Generator Load Imbalance made pursuant to the Open Access Transmission Tariff (OATT).

Schedule Page: 326 Line No.: 7 Column: a

JOINT ACCOUNT PURCHASES	CHARGES	MWH
ARKANSAS ELECTRIC COOP CORP	$82,228	1,361
ASSOCIATED ELECTRIC COOP INC	1,601,799	42,260
AEP SERVICE CORP	4,000	116
BOARD OF PUBLIC UTILITIES	504	8
CALPINE ENERGY SERVICES	197,982	5,371
CARGILL ENG CHG	4,677,612	110,410
CITY UTILITIES OF SPRINGFIELD	360	9
CITY WATER & LIGHT	14,238	274
CLARKSDALE	-	1
CLECO	1,765	37
CONOCO PHILLIPS COMPANY	6,209	124
CONSTELLATION ENERGY	4,265	110
EMPIRE DISTRICT ELECTRIC COMPANY	696	16
EXELON GENERATION COMPANY	162,138	4,153
GRAND RIVER DAM AUTHORITY	1,559	16
INDEPENDENCE POWER AND LIGHT	124	2
KANSAS CITY POWER & LIGHT	303,990	4,397
LAFAYETTE ENERGY	76	1
LOUISIANA ENERGY AND POWER AUTHORITY	106	2
MAGNET COVE ENERGY	20,736	747
MERRILL LYNCH COMMODITIES INC	17,947,696	476,421
NEBRASKA PUBILC POWER DISTRICT ENERGY	2,588	46
NRG POWER MARKETING	26,478,309	604,615
OCCIDENTAL POWER SERVICES INC	866,633	24,515
OKLAHOMA GAS & ELECTRIC	4,039	104
OMAHA PUBLIC POWER DISTRCIT ENERGY	2,001	41

RAINBOW ENERGY MARKETING CORP	979	50
SOUTH MISSISSIPPI ELECTRIC POWER ASSOC	636,017	8,426
SOUTHERN COMPANY SERVICES INC	324,565	5,176
SOUTHWEST POWER POOL	14,234	1,361
SOUTHWESTERN POWER ADMINISTRATION	974	19
SOUTHWESTERN PUBLIC SERVICE	3,483	91
SUNFLOWER ELECTRIC POWER CORPORATION	857	15
TENASKA POWER SERVICES CO	1,278,378	29,696
TENNESSEE VALLEY AUTHORITY	62,893	3,,158
UNION ELECTRIC	4,715,622	159,251
UNION POWER PARTNERS	14,446,366	375,831
WESTAR ENERGY INC	151,244	4,421
WESTERN AREA POWER ADMINSTRATI	3,641	87
WESTERN FARMERS ELEC CORP	1,218	20
WRIGHTSVILLE POWER	15,550	541
JOINT ACCOUNT PURCHASES	6,813	147
Total System Purchases From Others (a)	$74,044,486	1,862,087

(a)Includes purchases made pursuant to the Generator Imbalance Agreement (GIA) for over delivery of energy.

Schedule Page: 326 Line No.: 8 Column: k

	CHARGES	MWH
MISO Ancillary	$19,143	-
MISO Congestion	1,231,337	-
MISO Energy Purchases	1,517,801	43,725
MISO Losses	74,775	-
MISO Uplift	53,497	-
Total Energy Purchases From MISO	$2,896,553	43,725

Schedule Page: 326 Line No.: 8 Column: l

	CHARGES	MWH
MISO Sch 24 Admin	$24,526	-

Schedule Page: 326.1 Line No.: 5 Column: c

(2) ** FERC rate schedules are classified as special contract PPA’s.

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Air Liquide America Corporation (2)			
2	Ameren Energy, Inc. (1)			
3	Ameren Energy Marketing Peoroa			
4	American Electric Power (1)			OS
5	Arkansas Electric Cooperative Corp. (1,2)			OS
6	Associated Electric Cooperative, Inc.			OS
7	BASF Corporation (2)			
8	Brazos Electric Power Cooperative, Inc. (1,2)			
9	Buffalo Dunes Wind			
10	Calpine Energy Services, LP			OS
11	Cargill-Alliant, LLC			OS
12	Carthage Water and Electric Plant			LFP
13	Central Louisiana Electric Company (1,2)			OS
14	Chisholm View Wind			
15	Cll Carbon, LLC (2)			
16	Citigroup Energy Inc.			OS
17	City of Benton (1)			
18	City of Caldwell (1)			
19	City of Hope			LFP
20	City of Independence P&L			OS
21	City of Kirbyville (1)			
22	City of Malden Board of Public Works			LFP
23	City of Newton (1)			
24	City of Osceola (1)			
25	City of Prescott (1)			
26	City of West Memphis (1)			
27	City Utilities of Springfield MO			OS
28	City Water & Light			LFP
29	Conoco, Inc.			OS
30	Constellation Power Source			OS
31	Conway Corporation (1)			
32	Dow Chemical Company (2)			
33	Eagle US (2)			
34	East Texas Electric Cooperative (1,2)			LFP
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	EDF Trading North America, LLC			OS
2	Empire District Electric Co.			OS
3	ETC Endure Energy LLC			OS
4	EWO Marketing, LLC (1)			OS
5	Exelon Generation Co.			OS
6	Exxon Mobil Oil Corporation (2)			
7	Formosa Plastics Corporation (2)			
8	Georgia Gulf Corporation (2)			
9	Grand River Dam Authority			OS
10	Huntsman Corporation (2)			
11	J. Aron & Company			
12	JP Morgan Ventures Energy			
13	Kansas City Board of Public Utilities			OS
14	Kansas City Power & Light			OS
15	Kansas Energy LLC			
16	KCPL Greater Missouri Operations			OS
17	Lincoln Electric System			OS
18	Louisiana Energy & Power Authority (1,2)			OS
19	Louisiana Generating, LLC (1)			OS
20	Merrill Lynch Commodities			OS
21	Mid American Energy Company			LFP
22	Miscellaneous Sale/Purchase (2)			
23	Mississippi Delta Energy Agency (1,2)			
24	Missouri Joint Municipal Electric Utility Comm			LFP
25	Missouri Joint Municipal EUC - Thayer (1)			
26	Morgan Stanley Capital Group			OS
27	Municipal Energy Agency of Mississippi			LFP
28	Municipal Light Water & Sewer City of Piggott			LFP
29	Nebraska Public Power District			OS
30	North Little Rock Electric Department (1)			
31	Occidental Chemical Corporation (1,2)			
32	Oklahoma Gas & Electric			
33	Omaha Public Power District			OS
34	Pine Bluff Energy (2)			
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Plum Point Energy Associates			OS
2	Poplar Bluff Municipal			OS
3	Rainbow Energy Marketing Corp.			
4	RS Cogen, LLC (2)			
5	Ruston (1)			
6	Sabine Cogen, LP (2)			
7	Shell Chemical, LP (2)			
8	South Mississippi Electric Power Assoc.			OS
9	Southern Company Services, Inc.			LFP
10	Southwestern Electric Coop			LFP
11	Southwestern Power Administration			
12	Southwestern Public Service Co.			OS
13	SRW Cogeneration, LP (2)			
14	Suez Energy Marketing			
15	Tenaska Power Services Company (1,2)			OS
16	Tennessee Valley Authority (1)			OS
17	The Energy Authority, Inc.			OS
18	Union Carbide Corporation (2)			
19	Union Power Partners, LP			OS
20	Vinton Public Power Authority (1)			
21	Westar Energy			OS
22	Western Farmers Electric			OS
23	Wrightsville Power (2)			
24	ENTERGY/EMO			OS
25	Oklahoma Energy Resources, Inc			OS
26	MISO	Various	Various	
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
GIA						1
OATT						2
OATT						3
OATT	(3)	(3)		1,106	1,073	4
OATT	(3)	(3)		349	338	5
OATT	(3)	(3)		449,926	436,429	6
GIA						7
OATT						8
OATT						9
OATT	(3)	(3)		1,292	1,253	10
OATT	(3)	(3)		446,510	433,115	11
OATT	(3)	(3)		15,708	15,237	12
OATT	(3)	(3)		24,819	24,074	13
OATT						14
GIA						15
OATT	(3)	(3)		1,655	1,606	16
OATT						17
OATT						18
OATT	(3)	(3)		17,453	16,929	19
OATT	(3)	(3)		8	8	20
OATT						21
OATT	(3)	(3)		8,727	8,465	22
OATT						23
OATT						24
OATT						25
OATT						26
OATT	(3)	(3)		71	69	27
OATT	(3)	(3)		454,259	440,631	28
OATT	(3)	(3)		844	819	29
OATT	(3)	(3)		1,510	1,464	30
OATT						31
GIA						32
GIA						33
OATT	(3)	(3)		54,105	52,481	34
			0	**6,220,096**	**6,033,493**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
OATT	(3)	(3)		6,557	6,360	1
OATT	(3)	(3)		174,846	169,601	2
OATT	(3)	(3)		1,710	1,659	3
OATT	(3)	(3)		119,623	116,034	4
OATT	(3)	(3)		953	925	5
GIA						6
GIA						7
GIA						8
OATT	(3)	(3)		482	467	9
GIA						10
OATT						11
OATT						12
OATT	(3)	(3)		125	122	13
OATT	(3)	(3)		1,097	1,064	14
OATT						15
OATT	(3)	(3)		432,737	419,755	16
OATT	(3)	(3)		157	152	17
OATT	(3)	(3)		5,441	5,277	18
OATT	(3)	(3)		1,345,464	1,305,100	19
OATT	(3)	(3)		514	499	20
OATT	(3)	(3)		102,227	99,160	21
GIA						22
OATT						23
OATT	(3)	(3)		113,172	109,777	24
OATT						25
OATT	(3)	(3)		338,303	328,154	26
OATT	(3)	(3)		92,501	89,726	27
OATT	(3)	(3)		10,472	10,158	28
OATT	(3)	(3)		226	219	29
OATT						30
GIA						31
OATT						32
OATT	(3)	(3)		278	269	33
GIA						34
			0	**6,220,096**	**6,033,493**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
OATT	(3)	(3)		61,568	59,721	1
OATT	(3)	(3)		33,511	32,506	2
OATT						3
GIA						4
OATT						5
GIA						6
GIA						7
OATT	(3)	(3)		1,079,992	1,047,593	8
OATT	(3)	(3)		352,552	341,976	9
OATT	(3)	(3)		32,024	31,064	10
OATT						11
OATT	(3)	(3)		193	187	12
GIA						13
OATT						14
OATT	(3)	(3)		10,366	10,055	15
OATT	(3)	(3)		8,283	8,034	16
OATT	(3)	(3)		62,300	60,431	17
GIA						18
OATT	(3)	(3)		252,709	245,127	19
OATT						20
OATT	(3)	(3)		65,349	63,388	21
OATT	(3)	(3)		34	33	22
GIA						23
	(3)	(3)		35,130	34,076	24
	(3)	(3)		858	833	25
	Various	Various				26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**6,220,096**	**6,033,493**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		2,086	2,086	1
		222,255	222,255	2
	-8		-8	3
	3,537	135,829	139,366	4
	1,024,349	17,577	1,041,926	5
761,608	278,685		1,040,293	6
		2,086	2,086	7
	394,926	362,773	757,699	8
65,626			65,626	9
	3,520		3,520	10
831,963	151,390		983,353	11
32,570	1,851		34,421	12
	56,566	2,360,074	2,416,640	13
-1,270			-1,270	14
		2,104	2,104	15
	8,065		8,065	16
		231,785	231,785	17
		50,280	50,280	18
35,945			35,945	19
	28		28	20
		18,934	18,934	21
18,094	1,239		19,333	22
		21,441	21,441	23
		124,907	124,907	24
		56,915	56,915	25
		304,867	304,867	26
	245		245	27
296,981	45,978		342,959	28
	3,355		3,355	29
	2,842		2,842	30
		757,387	757,387	31
		2,603	2,603	32
		2,086	2,086	33
111,429	10,480	1,704,200	1,826,109	34
8,953,651	**6,472,139**	**18,187,690**	**33,613,480**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	19,970		19,970	1
359,490	21,557		381,047	2
	6,684		6,684	3
	287,249	352,498	639,747	4
	2,736		2,736	5
		8,573	8,573	6
		2,086	2,086	7
		2,104	2,104	8
	1,922		1,922	9
		2,086	2,086	10
	-191		-191	11
	-29		-29	12
	505		505	13
	2,844		2,844	14
	-102		-102	15
880,668	1,386		882,054	16
	546		546	17
8,378	609	474,805	483,792	18
2,076,535	951,945	7,903,035	10,931,515	19
	1,150		1,150	20
177,421			177,421	21
		35	35	22
		251,362	251,362	23
238,849	11,661		250,510	24
		15,546	15,546	25
688,745	43,944		732,689	26
190,507	10,116		200,623	27
21,714	1,305		23,019	28
	592		592	29
		781,900	781,900	30
		7,560	7,560	31
	3,310		3,310	32
	1,041		1,041	33
		2,166	2,166	34
8,953,651	**6,472,139**	**18,187,690**	**33,613,480**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
135,498	6,557		142,055	1
69,244	3,672		72,916	2
	-105		-105	3
		2,131	2,131	4
		227,452	227,452	5
		2,104	2,104	6
		2,051	2,051	7
992,951	1,398,571		2,391,522	8
765,485	97		765,582	9
51,738	4,296		56,034	10
	-9		-9	11
	594		594	12
		2,599	2,599	13
	-11,007		-11,007	14
	40,994	42,194	83,188	15
	23,767	87,161	110,928	16
31,590	131,042		162,632	17
		2,086	2,086	18
	568,756		568,756	19
		1,624,764	1,624,764	20
111,892	48,086		159,978	21
	113		113	22
		11,203	11,203	23
				24
				25
	898,917		898,917	26
				27
				28
				29
				30
				31
				32
				33
				34
8,953,651	**6,472,139**	**18,187,690**	**33,613,480**	

Schedule Page: 328 Line No.: 1 Column: a

(2) Other charges include annual billing fees, tariff penalties, and prior period adjustments for the Generator Imbalance Agreement (GIA).

Schedule Page: 328 Line No.: 2 Column: a

(1) Other charges include network transmission service revenue as well as an ancillary service charges related to the Open Access Transmission Tariff (OATT).

Schedule Page: 328 Line No.: 2 Column: m

Other Charges

Customer	Network Transmission Revenue	Scheduling System Control& Dispatch	RTO & ICT Operations Recov	Total
Ameren Energy Inc.	$210,578	$6,014	$5,663	$222,255
American Electric Power	128,614	3,717	3,498	135,829
Brazos Electric Power Coop, Inc	345,804	8,741	8,228	362,773
Central Louisiana Elec Company	2,249,001	57,210	53,863	2,360,074
City of Benton	220,861	5,627	5,297	231,785
City of Caldwell	45,029	1,231	1,159	47,419
City of Kirbyville	16,976	460	433	17,869
City of Newton	19,284	499	469	20,252
City Of Osceola	118,028	3,542	3,337	124,907
City of Prescott	53,516	1,750	1,649	56,915
City of West Memphis	289,242	8,048	7,577	304,867
Conway Corporation	717,310	20,640	19,437	757,387
East Texas Electric Cooperative	1,622,214	42,224	39,762	1,704,200
EWO Marketing, LLC	314,862	9,153	8,619	332,634
Louisiana Energy & Power Auth	450,075	12,774	11,956	474,805
Louisiana Generating, LLC	7,533,414	190,374	179,247	7,903,035
Miss Delta Energy Agency (a)	214,687	5,876	5,531	226,094
Missouri Joint Mun EUC - Thayer	13,965	396	373	14,734
North Little Rock Elec Dept	743,263	19,901	18,736	781,900
Ruston	216,680	5,549	5,223	227,452
Tennessee Valley Authority	82,911	2,189	2,061	87,161
Vinton Public Power Authority	1,430,322	55,910	52,861	1,539,093
	$17,036,636	$461,825	$434,979	$17,933,440

Customer	Regulation & Frequency Response	Spinning Reserve	Supplemental Reserve	Total
City of Caldwell	$700	$1,083	$1,078	$2,861
City of Kirbyville	261	403	401	1,065
City of Newton	291	450	448	1,189
EWO Marketing, LLC	4,863	7,518	7,483	19,864
Miss Delta Energy Agency (a)	2,587	4,000	3,981	10,568
Missouri Joint Mun EUC - Thayer	199	307	306	812
Vinton Public Power Authority	20,972	32,424	32,275	85,671
	$29,873	$46,185	$45,972	$122,030
Other				132,220
Total Other Charges				$18,187,690

(a) Includes $14,700 in Other

Schedule Page: 328 Line No.: 4 Column: f

(3) Multiple points of delivery and receipt under the Open Access Transmission Tariff (OATT); therefore, specific points of delivery and receipt can not be reported.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Arkansas Electric				48,675			48,675
2	Cooperative Corp.							
3								
4	Associated Electric				249,392			249,392
5	Cooperative, Inc.							
6								
7	Southwestern Power Adm				250,597			250,597
8								
9	Louisiana Generating				10,764			10,764
10	LLC							
11								
12	East Texas Electric				463,151			463,151
13	Coop Inc							
14								
15	Central Louisiana				497,910			497,910
16	Electric Co							
	TOTAL				1,520,489			1,520,489

Schedule Page: 332 Line No.: 1 Column: a

The agreement between Entergy Arkansas, Inc. and Arkansas Electric Cooperative Corporation was amended in February 1995. Based on the new agreement, Entergy Arkansas, Inc. pays a monthly demand charge for the use of the wheeling services.

Schedule Page: 332 Line No.: 4 Column: a

These expenses represent the charges incurred from a third party for the utilization of their transmission system by Entergy Arkansas, Inc. These transmission expenses are associated with either a sale of bulk power to an external company or a purchase of bulk power from an external company.

Schedule Page: 332 Line No.: 7 Column: a

Respondent delivers energy to Water Valley, Arkansas, and SPA wheels energy to Respondent's customers at Ash Flat, Arkansas.

Schedule Page: 332 Line No.: 9 Column: a

These expenses represent the charges incurred from a third party for the utilization of their transmission system by Entergy Arkansas, Inc. These transmission expenses are associated with either a sale of bulk power to an external company or a purchase of bulk power from an external company.

Schedule Page: 332 Line No.: 12 Column: a

These expenses represent the charges incurred from a third party for the utilization of their transmission system by Entergy Arkansas, Inc. These transmission expenses are associated with either a sale of bulk power to an external company or a purchase of bulk power from an external company.

Schedule Page: 332 Line No.: 15 Column: a

These expenses represent the charges incurred from a third party for the utilization of their transmission system by Entergy Arkansas, Inc. These transmission expenses are associated with either a sale of bulk power to an external company or a purchase of bulk power from an external company.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	636,338
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	415,494
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	5% Surcharge on regulated company billings to	
7	non-regulated affiliates	-1,876,009
8	Directors meetings and expenses	19,371
9	Irrigation load control amortization	760,883
10	Communication services	17,195
11	System aviation	179,125
12	Section 263A research - tax services	73,632
13	Public relations expense	8,440
14	Community relations	15,418
15	Purchasing and contracts support	300,249
16	Transco implementation	19,454
17	Ice Storm securitization amortization	20,728
18	Other	-67,132
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
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44		
45		
46	TOTAL	523,186

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			16,381,932		16,381,932
2	Steam Production Plant	16,560,270	-159,774			16,400,496
3	Nuclear Production Plant	53,645,959				53,645,959
4	Hydraulic Production Plant-Conventional	574,609	-2,188			572,421
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	15,855,831	-24			15,855,807
7	Transmission Plant	30,224,388				30,224,388
8	Distribution Plant	79,345,469				79,345,469
9	Regional Transmission and Market Operation	21,390		1,189,893		1,211,283
10	General Plant	15,866,365				15,866,365
11	Common Plant-Electric					
12	TOTAL	212,094,281	-161,986	17,571,825		229,504,120

B. Basis for Amortization Charges

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Production Steam:						
13	Couch Common 311	838	108.00	-32.00		R3	
14	Couch Unit 2 311	1,707	108.00	-32.00	0.05	R3	
15	Independence Common	11,006	108.00	-17.00		R3	
16	Independence Unit 1 311	976	108.00	-17.00	0.01	R3	
17	Lake Catherine Common	1,982	108.00	-40.00		R3	
18	Lake Catherine Unit 1 3	1,124	108.00	-40.00	0.01	R3	
19	Lake Catherine Unit 2 3	1,138	108.00	-40.00	0.01	R3	
20	Lake Catherine Unit 3 3	1,342	108.00	-40.00	0.02	R3	
21	Lake Catherine Unit 4 3	4,825	108.00	-40.00	0.02	R3	
22	Lynch Common 311	3,061	108.00	-34.00		R3	
23	Lynch Unit 1 311	1,092	108.00	-34.00	0.02	R3	
24	Lynch Unit 3 311	2,052	108.00	-34.00	0.02	R3	
25	Ritchie Common 311	2,528	108.00	-25.00	0.01	R3	
26	Ritchie Unit 1 311		108.00	-25.00	0.03	R3	
27	White Bluff Skills Cent	340	108.00	-18.00	0.01	R3	
28	White Bluff Common 311	4,254	108.00	-18.00	0.02	R3	
29	White Bluff Unit 1 311	34,405	108.00	-18.00	0.01	R3	
30	White Bluff Unit 2 311	6,976	108.00	-18.00	0.01	R3	
31	Couch Common 312	27	75.00	-32.00	0.10	R3	
32	Couch Unit 2 312	8,377	75.00	-32.00	0.05	R3	
33	Independence Common	17,930	75.00	-17.00	0.01	R3	
34	Independence Unit 1 312	76,417	75.00	-17.00	0.01	R3	
35	Lake Catherine Common	478	75.00	-40.00	0.03	R3	
36	Lake Catherine Unit 1 3	2,519	75.00	-40.00	0.05	R3	
37	Lake Catherine Unit 2 3	2,296	75.00	-40.00	0.04	R3	
38	Lake Catherine Unit 3 3	5,650	75.00	-40.00	0.06	R3	
39	Lake Catherine Unit 4 3	27,204	75.00	-40.00	0.02	R3	
40	Lynch Unit 1 312	54	75.00	-34.00	0.05	R3	
41	Lynch Unit 3 312	8,194	75.00	-34.00	0.05	R3	
42	Moses Unit 1 312		75.00	-34.00	0.01	R3	
43	Ritchie Common 312	759	75.00	-25.00	0.05	R3	
44	White Bluff Common 312	47,610	75.00	-18.00	0.03	R3	
45	White Bluff Unit 1 312	138,330	75.00	-18.00	0.02	R3	
46	White Bluff Unit 2 312	130,674	75.00	-18.00	0.02	R3	
47	Couch Common 314	51	75.00	-32.00	0.18	R4	
48	Couch Unit 2 314	5,516	75.00	-32.00	0.07	R4	
49	Independence Common	867	75.00	-17.00	0.01	R4	
50	Independence Unit 1 314	33,289	75.00	-17.00	0.01	R4	

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Lake Catherine Common	152	75.00	-40.00	0.05	R4	
13	Lake Catherine Unit 1 3	1,706	75.00	-40.00	0.01	R4	
14	Lake Catherine Unit 2 3	1,703	75.00	-40.00	0.01	R4	
15	Lake Catherine Unit 3 3	3,413	75.00	-40.00	0.05	R4	
16	Lake Catherine Unit 4 3	15,277	75.00	-40.00	0.01	R4	
17	Lynch Common 314	22	75.00	-34.00	0.21	R4	
18	Lynch Unit 3 314	10,929	75.00	-34.00	0.06	R4	
19	Ritchie Common 314	124	75.00	-25.00	0.01	R4	
20	White Bluff Common 314	1,248	75.00	-18.00	0.02	R4	
21	White Bluff Unit 1 314	39,331	75.00	-18.00	0.01	R4	
22	White Bluff Unit 2 314	48,375	75.00	-18.00	0.01	R4	
23	Couch Common 315	338	74.00	-32.00	0.10	R4	
24	Couch Unit 2 315	3,053	74.00	-32.00	0.02	R4	
25	Independence Common	817	74.00	-17.00	0.02	R4	
26	Independence Unit 1 315	13,003	74.00	-17.00	0.01	R4	
27	Lake Catherine Common	287	74.00	-40.00	0.03	R4	
28	Lake Catherine Unit 1 3	1,596	74.00	-40.00	0.05	R4	
29	Lake Catherine Unit 2 3	1,423	74.00	-40.00	0.04	R4	
30	Lake Catherine Unit 3 3	1,784	74.00	-40.00	0.08	R4	
31	Lake Catherine Unit 4 3	6,847	74.00	-40.00	0.02	R4	
32	Lynch Common 315	301	74.00	-34.00	0.19	R4	
33	Lynch Unit 1 315	240	74.00	-34.00	0.01	R4	
34	Lynch Unit 3 315	2,132	74.00	-34.00	0.07	R4	
35	Ritchie Common 315	110	74.00	-25.00	0.04	R4	
36	White Bluff Common 315	1,788	74.00	-25.00	0.02	R4	
37	White Bluff Skills Cent	26	74.00	-18.00	0.01	R4	
38	White Bluff Unit 1 315	20,080	74.00	-18.00	0.01	R4	
39	White Bluff Unit 2 315	16,366	74.00	-18.00	0.02	R4	
40	Couch Common 316	280	73.00	-32.00	0.13	R3	
41	Couch Unit 2 316	279	73.00	-32.00	0.04	R3	
42	Independence Common	1,876	73.00	-17.00	0.02	R3	
43	Independence Unit 1 316	2,090	73.00	-17.00	0.01	R3	
44	Lake Catherine Common	1,055	73.00	-40.00	0.04	R3	
45	Lake Catherine Unit 1 3	255	73.00	-40.00	0.02	R3	
46	Lake Catherine Unit 2 3	250	73.00	-40.00	0.02	R3	
47	Lake Catherine Unit 3 3	107	73.00	-40.00	0.06	R3	
48	Lake Catherine Unit 4 3	533	73.00	-40.00	0.04	R3	
49	Lynch Common 316	78	73.00	-34.00	0.10	R3	
50	Lynch Unit 1 316	124	73.00	-34.00	0.02	R3	

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Lynch Unit 3 316	625	73.00	-34.00	0.10	R3	
13	Moses Common 316	6	73.00	-34.00	0.14	R3	
14	Ritchie Common 316	519	73.00	-25.00	0.02	R3	
15	White Bluff Common 316	3,129	73.00	-25.00	0.02	R3	
16	White Bluff Skills Cent	644	73.00	-18.00	0.01	R3	
17	White Bluff Unit 1 316	2,968	73.00	-18.00	0.01	R3	
18	White Bluff Unit 2 316	1,084	73.00	-18.00	0.01	R3	
19	Total Production Steam:	794,257					
20							
21							
22	ANO Unit 1 320.2	1,598	70.00		0.03	R3	
23	ANO Common 321.2	121,372	87.00		0.02	R2	
24	ANO Unit 1 321.2	136,084	87.00		0.01	R2	
25	ANO Unit 2 321.2	219,110	87.00		0.01	R2	
26	ANO Common 322	30,997	40.00	-2.00	0.03	R1.5	
27	ANO Unit 1 322	530,576	40.00	-2.00	0.04	R1.5	
28	ANO Unit 2 322	623,728	40.00	-2.00	0.03	R1.5	
29	ANO Common 323	5,652	56.00	-2.00	0.03	R2	
30	ANO Unit 1 323	164,731	56.00	-2.00	0.02	R2	
31	ANO Unit 2 323	168,347	56.00	-2.00	0.02	R2	
32	ANO Common 324	27,717	55.00	-1.00	0.02	R2	
33	ANO Unit 1 324	116,616	55.00	-1.00	0.01	R2	
34	ANO Unit 2 324	126,740	55.00	-1.00	0.01	R2	
35	ANO Common 325	119,330	57.00		0.02	R2.5	
36	ANO Unit 1 325	77,998	57.00		0.01	R2.5	
37	ANO Unit 2 325	34,328	57.00		0.01	R2.5	
38	Total Production Nuclea	2,504,923					
39							
40							
41	Carpenter Common 330.2	267	75.00	-5.00	0.01	R3	
42	Carpenter Common 331.1	340	109.00	-5.00	0.02	S3	
43	Carpenter Unit 1 331.1	533	109.00	-5.00		S3	
44	Carpenter Unit 2 331.1	533	109.00	-5.00		S3	
45	Remmel Common 331.1	521	109.00	-5.00	0.02	S3	
46	Remmel Unit 1 331.1	51	109.00	-5.00	0.01	S3	
47	Remmel Unit 2 331.1	74	109.00	-5.00		S3	
48	Remmel Unit 3 331.1	77	109.00	-5.00	0.01	S3	
49	Carpenter Common 331.2	30	109.00	-5.00	0.02	S3	
50	Remmel Common 331.2	18	109.00	-5.00	0.02	S3	

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Remmel Unit 1 331.2	12	109.00	-5.00	0.01	S3	
13	Remmel Unit 2 331.2	25	109.00	-5.00		S3	
14	Remmel Unit 3 331.2	11	109.00	-5.00	0.01	S3	
15	Carpenter Common 331.3	272	109.00	-5.00	0.02	S3	
16	Carpenter Unit 1 331.3	9	109.00	-5.00		S3	
17	Carpenter Unit 2 331.3	9	109.00	-5.00		S3	
18	Remmel Common 331.3	324	109.00	-5.00	0.02	S3	
19	Remmel Unit 1 331.3	1	109.00	-5.00	0.01	S3	
20	Remmel Unit 2 331.3	1	109.00	-5.00		S3	
21	Remmel Unit 3 331.3	1	109.00	-5.00	0.01	S3	
22	Carpenter Common 332.1	2,383	105.00	-10.00	0.02	R5	
23	Carpenter Unit 1 332.1	1,356	105.00	-10.00	0.01	R5	
24	Carpenter Unit 2 332.1	1,376	105.00	-10.00	0.01	R5	
25	Remmel Common 332.1	8,297	105.00	-10.00	0.02	R5	
26	Remmel Unit 1 332.1	513	105.00	-10.00	0.01	R5	
27	Remmel Unit 2 332.1	513	105.00	-10.00	0.01	R5	
28	Remmel Unit 3 332.1	513	105.00	-10.00	0.01	R5	
29	Remmel Common 332.2	36	105.00	-10.00	0.02	R5	
30	Carpenter Common 332.3	10	105.00	-10.00	0.02	R5	
31	Carpenter Common 333	909	77.00	-15.00	0.02	L2	
32	Carpenter Unit 1 333	4,311	77.00	-15.00	0.02	L2	
33	Carpenter Unit 2 333	5,499	77.00	-15.00	0.02	L2	
34	Remmel Common 333	859	77.00	-15.00	0.02	L2	
35	Remmel Unit 1 333	1,472	77.00	-15.00	0.02	L2	
36	Remmel Unit 2 333	1,438	77.00	-15.00	0.03	L2	
37	Remmel Unit 3 333	131	77.00	-15.00	0.01	L2	
38	Carpenter Common 334	92	73.00	-5.00	0.03	R1.5	
39	Carpenter Unit 1 334	116	73.00	-5.00	0.01	R1.5	
40	Carpenter Unit 2 334	303	73.00	-5.00	0.01	R1.5	
41	Remmel Common 334	421	73.00	-5.00	0.03	R1.5	
42	Remmel Unit 1 334	123	73.00	-5.00	0.01	R1.5	
43	Remmel Unit 2 334	32	73.00	-5.00	0.01	R1.5	
44	Remmel Unit 3 334	32	73.00	-5.00	0.01	R1.5	
45	Carpenter Common 335.1	1,245	77.00		0.02	R1.5	
46	Carpenter Unit 1 335.1	99	77.00			R1.5	
47	Carpenter Unit 2 335.1	101	77.00			R1.5	
48	Remmel Common 335.1	356	77.00		0.03	R1.5	
49	Remmel Unit 1 335.1	14	77.00			R1.5	
50	Remmel Unit 2 335.1	14	77.00			R1.5	

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Remmel Unit 3 335.1	14	77.00			R1.5	
13	Carpenter Common 335.2	12	77.00		0.02	R1.5	
14	Carpenter Common 335.3	292	77.00		0.02	R1.5	
15	Carpenter Unit 1 335.3	3	77.00			R1.5	
16	Carpenter Unit 2 335.3	3	77.00			R1.5	
17	Total Prod Hydro:	35,997					
18							
19							
20	Blytheville Gas Turbine	58				Indeterminate	
21	Hot Spring Block 1 341	11,267	30.00		0.04	SQ	
22	Hot Spring Block 1 342	1,386	30.00		0.04	SQ	
23	Hot Spring Block 1 343	9,823	30.00		0.04	SQ	
24	Hot Spring Block 1 344	190,417	30.00		0.04	SQ	
25	Hot Spring Block 1 345	1,516	30.00		0.04	SQ	
26	Hot Spring Block 1 346	889	30.00		0.04	SQ	
27	Lynch (Diesel) U1 343	720			0.04	S6	
28	Mabelvale Unit 1 341	124	64.00		0.08	S1	
29	Mabelvale Unit 1 342	58	55.00	-10.00		S2	
30	Mabelvale Unit 1 343	1,526	44.00	-5.00	0.03	S6	
31	Mabelvale Unit 1 344	420	57.00	-5.00		S0.5	
32	Mabelvale Unit 1 345	985	47.00	-5.00	0.08	S4	
33	Mabelvale Unit 1 346	8	52.00		0.01	R3	
34	Mabelvale Unit 2 341	11	64.00		0.01	S1	
35	Mabelvale Unit 2 342	49	55.00	-10.00		S2	
36	Mabelvale Unit 2 343	1,569	44.00	-5.00	0.03	S6	
37	Mabelvale Unit 2 344	569	57.00	-5.00	0.01	S0.5	
38	Mabelvale Unit 2 345	777	47.00	-5.00	0.08	S4	
39	Mabelvale Unit 2 346	3	52.00		0.01	R3	
40	Mabelvale Unit 3 341	106	64.00		0.01	S1	
41	Mabelvale Unit 3 342	49	55.00	-10.00		S2	
42	Mabelvale Unit 3 343	1,412	44.00	-5.00	0.01	S6	
43	Mabelvale Unit 3 344	349	57.00	-5.00		S0.5	
44	Mabelvale Unit 3 345	104	47.00	-5.00	0.03	S4	
45	Mabelvale Unit 3 346	3	52.00			R3	
46	Mabelvale Unit 4 341	14	64.00		0.01	S1	
47	Mabelvale Unit 4 342	49	55.00	-10.00		S2	
48	Mabelvale Unit 4 343	1,483	44.00	-5.00	0.03	S6	
49	Mabelvale Unit 4 344	607	57.00	-5.00	0.01	S0.5	
50	Mabelvale Unit 4 345	722	47.00	-5.00	0.08	S4	

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Mabelvale Unit 4 346	4	52.00			R3	
13	Ouachita Common 341	7,741	64.00		0.04	S1	
14	Ouachita Common 342	150			0.04	N/A	
15	Ouachita Common 343	9,520			0.04	N/A	
16	Ouachita Common 344	11,283	57.00		0.04	S0.5	
17	Ouachita Common 345	771			0.04	N/A	
18	Ouachita Common 346	1,080	52.00		0.04	R3	
19	Ouachita Unit 1 341	3,207	64.00		0.04	S1	
20	Ouachita Unit 1 342	49			0.04	N/A	
21	Ouachita Unit 1 343	1,801			0.04	N/A	
22	Ouachita Unit 1 344	54,348	57.00		0.04	S0.5	
23	Ouachita Unit 1 345	407			0.04	N/A	
24	Ouachita Unit 1 346	249			0.04	N/A	
25	Ouachita Unit 2 341	3,204	64.00		0.04	S1	
26	Ouachita Unit 2 342	45			0.04	N/A	
27	Ouachita Unit 2 343	1,432			0.04	N/A	
28	Ouachita Unit 2 344	54,306	57.00		0.04	S0.5	
29	Ouachita Unit 2 345	410			0.04	N/A	
30	Ouachita Unit 2 346	205			0.04	N/A	
31	Ritchie Unit 3 346				0.01	R3	
32	Total Production Other:	377,284					
33							
34							
35	Transmission Plant 350.	2,129	75.00		0.01	R3	
36	Transmission Plant 350.	42,460	75.00		0.01	R3	
37	Transmission Plant 352	46,871	55.00	-5.00	0.02	R3	
38	Transmission Plant 353	602,832	55.00	-10.00	0.02	R3	
39	Transmission Plant 354	144,217	62.00	-20.00	0.02	R5	
40	Transmission Plant 355	326,693	52.00	-20.00	0.02	R1	
41	Transmission Plant 356.	280,664	61.00	-25.00	0.02	R3	
42	Transmission Plant 356.	11,788	61.00	-25.00	0.02	R3	
43	Transmission Plant 356.	40,056	61.00	-25.00	0.02	R3	
44	Transmission Plant 357	19	50.00		0.02	S2.5	
45	Transmission Plant 358	39	45.00	-5.00	0.02	R2.5	
46	Transmission Plant 359	1,900	75.00		0.01	R3	
47	Total Transmission:	1,499,668					
48							
49							
50	Distribution Plant 360.	3,543	65.00		0.01	R4	

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Distribution Plant 361	17,271	56.00	-5.00	0.02	R4	
13	Distribution Plant 362	360,754	55.00	-10.00	0.02	R1	
14	Distribution Plant 364	527,107	37.00	-35.00	0.03	S0.5	
15	Distribution Plant 365.	410,354	34.00	-25.00	0.03	R2	
16	Distribution Plant 365.	427	34.00	-25.00	0.03	R2	
17	Distribution Plant 365.	58,725	34.00	-25.00	0.03	R2	
18	Distribution Plant 366	91,916	51.00		0.02	R0.5	
19	Distribution Plant 367	143,583	39.00	-10.00	0.02	S0.5	
20	Distribution Plant 368.	675,950	31.00	-10.00	0.03	R1.5	
21	Distribution Plant 369.	139,047	41.00	-10.00	0.02	S1	
22	Distribution Plant 369.	121,085	35.00	-20.00	0.03	S2	22.60
23	Distribution Plant 370.	129,398	30.00		0.03	R2.5	
24	Distribution Plant 371	38,753	15.00	-5.00	0.07	L2	
25	Distribution Plant 373	82,519	20.00	-10.00	0.03	R0.5	
26	Distribution Plant 373.	776	20.00	-10.00	0.03	R0.5	
27	Total Distribution:	2,801,210					
28							
29							
30	RTO 382	107	5.00		0.20	SQ	
31	Total RTO:	107					
32							
33							
34	General Plant 390	86,066	49.00	-10.00	0.02	R1	
35	General Plant 391.1	1,611	20.00		0.05	SQ	
36	General Plant 391.2	23,349	5.00		0.20	SQ	
37	General Plant 391.3	3,682	15.00		0.07	SQ	
38	General Plant 392	13	15.00		0.07	SQ	
39	General Plant 393	1,049	15.00		0.07	SQ	
40	General Plant 394	14,620	15.00		0.07	SQ	
41	General Plant 395	861	10.00		0.10	SQ	
42	General Plant 396	233	15.00		0.07	SQ	
43	General Plant 397.1	6,079	10.00		0.10	SQ	
44	General Plant 397.2	37,278	15.00		0.07	SQ	
45	General Plant 398	3,556	10.00		0.10	SQ	
46	Total General Plant:	178,398					
47							
48	Total Depr Base:	8,191,844					
49							
50							

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13							
14							
15	Column balances are						
16	those used to compute						
17	depreciation charges						
18	for December, 2013.						
19							
20							
21							
22							
23							
24							
25							
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49							
50							

Schedule Page: 336 Line No.: 1 Column: d

Includes $11,237 of service company amortization billing allocations.

Schedule Page: 336 Line No.: 10 Column: b

Includes $7,065,531 of service company depreciation billing allocations.

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REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	FEDERAL ENERGY REGULATORY COMMISSION				
2	Docket No. RM87-3-000				
3	Annual Charges	1,020,508		1,020,508	
4					
5	Docket Nos. ER07-682-000 & ER07-956-001				
6	System Agreement Remedy Track II Schedule		15,044	15,044	
7					
8	Other expenses incurred in connection with				
9	various filings before FERC		7,673	7,673	
10					
11	Docket No. 07-138-TF				
12	APSC consultant fees incurred in federal				
13	cases		567,875	567,875	528,999
14					
15	Docket No. 09-084-U				
16	2009 EAI Rate Case				
17	(42 month amortization period)		529,931	529,931	528,878
18					
19	ARKANSAS PUBLIC SERVICE COMMISSION				
20	Docket No. 12-038-U				
21	Wholesale Baseload Capacity & Capacity				
22	Cost Recovery Rider		5,559	5,559	
23					
24	Docket No. 12-056-U				
25	Act 310 Filing		5,839	5,839	
26					
27	Docket No. 12-096-U				
28	EAI Rider AFCRG Filing		6,644	6,644	
29					
30	EAI Energy Efficiency		39,568	39,568	
31					
32	Docket No. 13-028-U				
33	2013 EAI Rate Case		902,438	902,438	
34					
35	Other expenses incurred in connection with				
36	various filings before the APSC		117,566	117,566	
37					
38	OTHER				
39	Expenses incurred in connection with various				
40	filings before the APSC and FERC		767,371	767,371	
41					
42	MISO Transition Costs		134	134	20,853
43					
44					
45					
46	TOTAL	1,020,508	2,965,642	3,986,150	1,078,730

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
							2
Electric	928	1,020,508					3
							4
							5
Electric	928	15,044					6
							7
							8
Electric	928	7,673					9
							10
							11
							12
Electric	928	567,875	621,243			1,150,243	13
							14
							15
							16
Electric	928	529,931			528,878		17
							18
							19
							20
							21
Electric	928	5,559					22
							23
							24
Electric	928	5,839					25
							26
							27
Electric	928	6,644					28
							29
Electric	928	39,568					30
							31
							32
Electric	928	902,438					33
							34
							35
Electric	928	117,566					36
							37
							38
							39
Electric	928	767,371					40
							41
Electric	928	134	96			20,949	42
							43
							44
							45
		3,986,150	621,339		528,878	1,171,192	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A(2)	
2	A(6)	Other
3	B(1)	EPRI Dues
4	B(1)	EPRI Dues
5	B(1)	EPRI Dues
6	B(1)	EPRI research
7	B(4)	MIT Carbon Sequestration Initiative
8	B(4)	Other
9		
10	Total	
11		
12	*253,408.1,426.5,560,568,592,926	
13	** 107, 568, 592	
14		
15		
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19		
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
121,613		107	121,613		1
74,093		*	74,093		2
	1,234,932	517	1,234,932		3
	538,332	506	538,332		4
	118,012	930.2	118,012		5
	246,370	506,923	246,370		6
	8,808	930.2	8,808		7
	245,080	**	245,080		8
					9
195,706	2,391,534		2,587,240		10
					11
					12
					13
					14
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	7,842,266		
4	Transmission	2,604,324		
5	Regional Market			
6	Distribution	11,420,208		
7	Customer Accounts	5,847,532		
8	Customer Service and Informational	4,008,322		
9	Sales			
10	Administrative and General	5,169,998		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	36,892,650		
12	Maintenance			
13	Production	6,200,312		
14	Transmission	3,539,034		
15	Regional Market			
16	Distribution	8,928,212		
17	Administrative and General	258,186		
18	TOTAL Maintenance (Total of lines 13 thru 17)	18,925,744		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	14,042,578		
21	Transmission (Enter Total of lines 4 and 14)	6,143,358		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	20,348,420		
24	Customer Accounts (Transcribe from line 7)	5,847,532		
25	Customer Service and Informational (Transcribe from line 8)	4,008,322		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	5,428,184		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	55,818,394		55,818,394
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

DISTRIBUTION OF SALARIES AND WAGES (Continued)

.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	55,818,394		55,818,394
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	37,315,739		37,315,739
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	37,315,739		37,315,739
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,794,218		2,794,218
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,794,218		2,794,218
77	Other Accounts (Specify, provide details in footnote):			
78	Fuel Stock Exp Undistributed (Account 152)	4,451,260		4,451,260
79	Stores Expense Undistributed (Account 163)	2,301,535		2,301,535
80	Miscellaneous Current and Accrued Assets (Account 174)	-2,581,331		-2,581,331
81	OTHER REGULATORY ASSETS (Account 182)	-56,299		-56,299
82	Clearing Accounts (Account 184)	3,026,844		3,026,844
83	Miscellaneous Deferred Debits (Account 186)	573,760		573,760
84	Accumulated Provisions for Property Insurance (Account 2281)	9,916,366		9,916,366
85	ACCUM PROV FOR INJURIES & DAM (Account 2282)	33,130		33,130
86	Accumulated Miscellaneous Operating Provisions (Account 2284)	7,974		7,974
87	DONATIONS (Account (4261)	191		191
88	Civil, Political, and Related Expenses (Account 4264)	226,086		226,086
89	Other Deductions (Account 4265)	761,155		761,155
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	18,660,671		18,660,671
96	TOTAL SALARIES AND WAGES	114,589,022		114,589,022

Schedule Page: 354 Line No.: 96 Column: d

The following payroll charges from Non-Nuclear Affiliate are not included in this schedule. These charges are included in the Electric O&M schedule (pages 320-323) only:

Production:	$11,107,496
Transmission:	$6,547,086
Regional Market:	$123,598
Distribution:	$2,018,372
Customer Accts:	$6,331,538
Customer Service:	$926,299
Sales:	$224,160
Administrative & General:	$25,389,847

In addition, Nuclear Affiliate production payroll charges of $103,041,396 and administrative and general charges of $4,364,361 are not included in this schedule. These charges are included in the Electric O&M schedule(pages 320-323)only.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				1,517,801
3	Net Sales (Account 447)				(5,579,153)
4	Transmission Rights				
5	Ancillary Services				19,143
6	Other Items (list separately)				
7	MISO Admin (Account 555)				24,526
8	MISO Congestion (Account 555)				1,231,337
9	MISO Losses (Account 555)				74,775
10	MISO Uplift (Account 555)				53,497
11					
12					
13					
14					
15					
16					
17					
18					
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43					
44					
45					
46	TOTAL				(2,658,074)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch				7,212,317	MWH	827,335
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response				331	MWH	29,872
4	Energy Imbalance	136,511	MWH	7,871,739	988	MWH	71,542
5	Operating Reserve - Spinning				331	MWH	46,184
6	Operating Reserve - Supplement				331	MWH	45,972
7	Other						
8	Total (Lines 1 thru 7)	136,511		7,871,739	7,214,298		1,020,905

Schedule Page: 398 Line No.: 1 Column: e

Units of MWH reported are related to tranmission services and ancillary services sold through December 18, 2013. Effective December 19, 2013, Entergy Arkansas, Inc. became a transmission owning member of Midwest Independent Transmission System Operator (MISO). Entergy Arkansas is no longer a transmission provider and no longer sells transmission services and ancillary services directly. Instead, Entergy Arkansas now receives revenues from transmission services and ancillary services sold by MISO. MISO distributes the revenue that it receives to the transmission owners.

Schedule Page: 398 Line No.: 3 Column: e

Dollars for Regulation and Frequency Response, Operating Reserve - Spinning and Operating Reserve - Supplement are derived from the same MWhrs.

Schedule Page: 398 Line No.: 5 Column: e

Dollars for Regulation and Frequency Response, Operating Reserve - Spinning and Operating Reserve - Supplement are derived from the same MWhrs.

Schedule Page: 398 Line No.: 6 Column: e

Dollars for Regulation and Frequency Response, Operating Reserve - Spinning and Operating Reserve - Supplement are derived from the same MWhrs.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	26,723	14	1900	16,598	3,472	2,878	1,995	1,384	396
2	February	23,833	14	800	14,846	2,966	2,878	1,742	1,401	
3	March	24,012	27	800	15,370	3,114	2,878	1,747	795	108
4	Total for Quarter 1	74,568			46,814	9,552	8,634	5,484	3,580	504
5	April	23,585	17	1700	15,222	2,679	2,898	1,585	849	352
6	May	26,065	20	1600	17,622	3,295	2,898	1,379	583	288
7	June	31,113	27	1700	21,159	4,324	2,842	1,831	957	
8	Total for Quarter 2	80,763			54,003	10,298	8,638	4,795	2,389	640
9	July	31,276	10	1600	20,537	4,130	2,842	1,982	1,635	150
10	August	32,309	8	1700	21,580	4,407	2,842	1,765	1,715	
11	September	30,106	3	1600	20,155	4,008	2,842	1,872	1,145	84
12	Total for Quarter 3	93,691			62,272	12,545	8,526	5,619	4,495	234
13	October	25,961	3	1600	17,661	3,399	2,842	1,549	360	150
14	November	25,053	28	900	15,954	3,698	2,842	1,603	878	78
15	December	26,021	16	800	16,644	3,726	2,842	1,597	771	441
16	Total for Quarter 4	77,035			50,259	10,823	8,526	4,749	2,009	669
17	Total Year to Date/Year	326,057			213,348	43,218	34,324	20,647	12,473	2,047

Schedule Page: 400 Line No.: 1 Column: a

The monthly transmission system peak load information represents all Entergy companies. Peak load by Entergy business units can be determined, but due to the format of transmission accounting, it is impractical to identify the monthly megawatt peak load by the statistical classifications requested.

Schedule Page: 400 Line No.: 17 Column: b

Due to the Entergy operating companies’ transition to MISO market participation, and as discussed in Entergy’s FERC filing, Docket ER13-948, data for the monthly transmission pricing zone peak loads are reflected below.

2013 Total Peak Load in KW

Month	Day	Hour	Entergy Arkansas	Entergy Gulf States Louisiana	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
1	14	1900	6,414,084	4,391,835	6,271,742	3,085,716	760,703	3,790,175
2	14	800	5,486,956	4,026,793	5,709,097	2,758,570	697,659	3,558,067
3	27	800	5,708,690	4,216,038	5,855,224	2,862,853	733,805	3,526,155
4	17	1700	5,427,758	4,320,579	5,925,040	2,952,240	769,168	2,842,451
5	20	1600	5,536,135	4,766,162	6,795,468	3,349,848	863,712	3,701,789
6	27	1700	7,621,607	5,305,832	7,503,001	3,933,178	1,003,637	4,523,932
7	10	1600	7,775,058	5,087,308	7,245,012	3,804,709	941,500	4,387,654
8	8	1700	7,351,992	5,505,160	7,697,205	4,043,464	1,022,946	4,694,692
9	3	1600	7,076,964	5,157,586	7,453,691	3,689,306	996,720	4,280,143
10	3	1600	6,160,046	4,700,336	6,488,749	3,212,126	890,079	3,783,823
11	28	900	5,708,483	4,512,205	6,316,373	2,814,371	774,037	3,700,368
12	16	800	5,764,184	4,540,526	6,451,919	2,905,413	785,943	4,091,411

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	20,859,162
3	Steam	10,681,590			
4	Nuclear	11,946,220	23	Requirements Sales for Resale (See instruction 4, page 311.)	261
5	Hydro-Conventional	130,609			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	8,929,533
7	Other				
8	Less Energy for Pumping		25	Energy Furnished Without Charge	34,091
9	Net Generation (Enter Total of lines 3 through 8)	22,758,419	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	1,845,264
10	Purchases	8,624,898	27	Total Energy Losses	
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	31,668,311
12	Received	323,443			
13	Delivered	225,052			
14	Net Exchanges (Line 12 minus line 13)	98,391			
15	Transmission For Other (Wheeling)				
16	Received	6,220,096			
17	Delivered	6,033,493			
18	Net Transmission for Other (Line 16 minus line 17)	186,603			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	31,668,311			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	2,914,575	975,675	5,050	15	800
30	February	2,627,293	940,410	4,976	1	800
31	March	2,727,374	959,287	4,751	25	800
32	April	1,945,142	353,102	4,218	5	800
33	May	2,339,997	621,343	4,651	29	1700
34	June	2,751,781	617,124	6,450	27	1400
35	July	2,733,389	502,123	6,349	9	1700
36	August	3,107,659	818,322	6,015	29	1700
37	September	2,996,488	953,886	5,942	9	1700
38	October	2,546,527	853,160	4,809	4	1500
39	November	2,489,985	771,223	4,987	25	1000
40	December	2,488,101	563,878	5,347	11	700
41	TOTAL	31,668,311	8,929,533			

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Arkansas Nuclear One* (b)	Plant Name: *White Bluff* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	N/A	Full Outdoor
3	Year Originally Constructed	1974	1980
4	Year Last Unit was Installed	1980	1981
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	1978.00	1026.00
6	Net Peak Demand on Plant - MW (60 minutes)	1878	1677
7	Plant Hours Connected to Load	12951	8757
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	1824	1659
10	When Limited by Condenser Water	1824	1659
11	Average Number of Employees	986	140
12	Net Generation, Exclusive of Plant Use - KWh	11946220000	6019362299
13	Cost of Plant: Land and Land Rights	2648089	1109655
14	Structures and Improvements	476761723	45981009
15	Equipment Costs	2029316577	451289731
16	Asset Retirement Costs	63301902	0
17	Total Cost	2572028291	498380395
18	Cost per KW of Installed Capacity (line 17/5) Including	1300.3176	485.7509
19	Production Expenses: Oper, Supv, & Engr	25832697	2518854
20	Fuel	75757279	158256327
21	Coolants and Water (Nuclear Plants Only)	5356758	0
22	Steam Expenses	33353747	1309409
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	654639
26	Misc Steam (or Nuclear) Power Expenses	30214246	3226854
27	Rents	4354780	141065
28	Allowances	0	63817
29	Maintenance Supervision and Engineering	17986116	474709
30	Maintenance of Structures	568410	1337589
31	Maintenance of Boiler (or reactor) Plant	11154470	9940176
32	Maintenance of Electric Plant	8694750	2552049
33	Maintenance of Misc Steam (or Nuclear) Plant	59730133	1007312
34	Total Production Expenses	273003386	181482800
35	Expenses per Net KWh	0.0229	0.0301

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		Nuclear		Coal		Oil
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		MWH		TON		BBL
38	Quantity (Units) of Fuel Burned	0	36172787	0	3645078	0	9050
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	3413800	0	8560	0	140463
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	2.097	0.000	43.120	0.000	120.640
42	Average Cost of Fuel Burned per Million BTU	0.000	0.614	0.000	2.520	0.000	20.450
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.006	0.000	0.030	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	10336.950	0.000	0.000	10376.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Hamilton Moses* (b)	Plant Name: *Cecil Lynch* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Full Outdoor	Full Outdoor
3	Year Originally Constructed	1951	1949
4	Year Last Unit was Installed	1951	1954
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	138.00	225.00
6	Net Peak Demand on Plant - MW (60 minutes)	0	0
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	144	130
10	When Limited by Condenser Water	135	130
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	0	-104000
13	Cost of Plant: Land and Land Rights	30709	89504
14	Structures and Improvements	0	3060767
15	Equipment Costs	6332	400918
16	Asset Retirement Costs	86051	128962
17	Total Cost	123092	3680151
18	Cost per KW of Installed Capacity (line 17/5) Including	0.8920	16.3562
19	Production Expenses: Oper, Supv, & Engr	0	224049
20	Fuel	0	786856
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	5287
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	11987
26	Misc Steam (or Nuclear) Power Expenses	0	366236
27	Rents	0	16517
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	33219
30	Maintenance of Structures	0	19545
31	Maintenance of Boiler (or reactor) Plant	0	23067
32	Maintenance of Electric Plant	0	44458
33	Maintenance of Misc Steam (or Nuclear) Plant	0	60600
34	Total Production Expenses	0	1591821
35	Expenses per Net KWh	0.0000	-15.3060

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)				Gas		Oil
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)				MCF		BBL
38	Quantity (Units) of Fuel Burned	0	0	0	2887	0	5
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	944900	0	140462
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	271.187	0.000	787.408
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	287.002	0.000	133.473
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	-7.528	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Ouachita 1& 2* (b)	Plant Name: *Hot Springs* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine	Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor	Outdoor
3	Year Originally Constructed	2002	2002
4	Year Last Unit was Installed	2002	2002
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	602.00	714.90
6	Net Peak Demand on Plant - MW (60 minutes)	521	614
7	Plant Hours Connected to Load	3509	4799
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	526	620
10	When Limited by Condenser Water	512	620
11	Average Number of Employees	33	18
12	Net Generation, Exclusive of Plant Use - KWh	1000705504	1723059415
13	Cost of Plant: Land and Land Rights	332811	1925135
14	Structures and Improvements	152617919	116462071
15	Equipment Costs	135835632	204031498
16	Asset Retirement Costs	0	0
17	Total Cost	288786362	322418704
18	Cost per KW of Installed Capacity (line 17/5) Including	479.7116	450.9983
19	Production Expenses: Oper, Supv, & Engr	1184206	798419
20	Fuel	30984496	59860908
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	597237	611352
26	Misc Steam (or Nuclear) Power Expenses	1713966	1940057
27	Rents	36584	50113
28	Allowances	4325	472
29	Maintenance Supervision and Engineering	261604	572049
30	Maintenance of Structures	110296	73104
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	5193291	11691187
33	Maintenance of Misc Steam (or Nuclear) Plant	216219	33796
34	Total Production Expenses	40302224	75631457
35	Expenses per Net KWh	0.0403	0.0439

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		Gas			Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		MCF			MCF	
38	Quantity (Units) of Fuel Burned	0	7452975	0	0	12479112	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	1023000	0	0	1017800	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	4.157	0.000	0.000	4.797	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	4.064	0.000	0.000	4.713	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.031	0.000	0.000	0.035	0.000
44	Average BTU per KWh Net Generation	0.000	7620.000	0.000	0.000	7370.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Independence* (d)	Plant Name: *Lake Catherine* (e)	Plant Name: *Robert Ritchie 3* (f)	Line No.
Steam	Steam	Gas Turbine	1
Full Outdoor	Full Outdoor	Outdoor	2
1983	1950	1970	3
1983	1970	1970	4
284.00	752.00	20.00	5
1746	525	0	6
8412	4186	0	7
0	0	0	8
1678	756	18	9
1657	756	16	10
125	39	0	11
1461736974	477684697	0	12
773576	33725	16583	13
11982420	6877639	514914	14
146279988	51833873	308059	15
0	322593	4455	16
159035984	59067830	844011	17
559.9859	78.5476	42.2006	18
808178	2384264	0	19
40808146	29333518	0	20
0	0	0	21
366456	994054	0	22
0	0	0	23
0	0	0	24
493596	571920	0	25
-225646	2075602	0	26
35022	93814	0	27
13481	8052	0	28
94534	349869	0	29
280181	163461	0	30
2567630	1408070	0	31
3007469	544883	0	32
474432	769461	0	33
48723479	38696968	0	34
0.0333	0.0810	0.0000	35

									Line No.
Coal		Oil		Gas					36
TON		BBL		MCF					37
877295	0	2313	0	5870595	0	0	0	0	38
8438	0	140479	0	1018300	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
46.160	0.000	134.150	0.000	4.997	0.000	0.000	0.000	0.000	41
2.740	0.000	22.740	0.000	4.907	0.000	0.000	0.000	0.000	42
0.030	0.000	0.000	0.000	0.061	0.000	0.000	0.000	0.000	43
0.000	10137.000	0.000	0.000	12514.000	0.000	0.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: Harvey Couch (d)	Plant Name: Mabelvale (e)	Plant Name: Robert Ritchie 1 (f)	Line No.
Steam	Gas Turbine	Steam	1
Full Outdoor	Outdoor	Outdoor	2
1943	1970	1961	3
1954	1970	1961	4
183.00	78.00	359.00	5
0	0	0	6
0	312	0	7
0	0	0	8
131	72	0	9
131	72	0	10
4	0	0	11
-837000	77789	-96000	12
9722	0	16583	13
837839	230772	514933	14
695956	4912882	307894	15
114735	17821	123276	16
1658252	5161475	962686	17
9.0615	66.1728	2.6816	18
416604	5074	0	19
912525	445963	3172	20
0	0	0	21
23126	0	0	22
0	0	0	23
0	0	0	24
35652	450	0	25
412534	55781	0	26
18477	0	0	27
0	0	0	28
4986	1461	0	29
74534	1582	0	30
6001	0	0	31
75267	47949	0	32
72261	40079	0	33
2051967	598339	3172	34
-2.4516	7.6918	-0.0330	35

(d)			(e)			(f)			Line No.
	Gas			Gas					36
	MCF			MCF					37
0	0	0	0	5837	0	0	0	0	38
0	0	0	0	1013600	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	76.409	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	75.383	0.000	0.000	0.000	0.000	42
0.000	-1.090	0.000	0.000	5.733	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	76050.000	0.000	0.000	0.000	0.000	44

Schedule Page: 403 Line No.: -1 Column: e

Lake Catherine

Lake Catherine Units 1, 2, and 3 were retired in 2013.

Schedule Page: 403 Line No.: -1 Column: f

Robert Ritchie 3

Robert Ritchie 3 Unit was retired in 2013.

Schedule Page: 402 Line No.: 1 Column: c

White Bluff

Reflects Entergy Arkansas, Inc.'s 57% interest in White Bluff Units 1, 2, and Common Plant.

Schedule Page: 403 Line No.: 1 Column: d

Independence

Reflects Entergy Arkansas Inc.’s 31.5% interest in Independence Unit 1 and its 15.75% interest in Common Plant.

Schedule Page: 403 Line No.: 1 Column: f

Robert Ritchie 3

Reflects Entergy Arkansas, Inc.'s 100% interest in Robert Ritchie 3 and its 40.74% interest in Common Plant.

Schedule Page: 402.1 Line No.: -1 Column: b

Hamilton Moses

Hamilton Moses Units 1 and 2 were retired in 2013.

Schedule Page: 402.1 Line No.: -1 Column: c

Cecil Lynch

Cecil Lynch Units 2 and 3 were retired in 2013.

Schedule Page: 403.1 Line No.: -1 Column: d

Harvey Couch

Harvey Couch Unit 2 was retired in 2013.

Schedule Page: 403.1 Line No.: -1 Column: e

Mabelvale

Mablevale Units 2 and 4 were retired in 2013.

Schedule Page: 403.1 Line No.: -1 Column: f

Robert Ritchie 1

Robert Ritchie 1 Unit was retired in 2013.

Schedule Page: 403.1 Line No.: 1 Column: f

Robert Ritchie 1

Reflects Entergy Arkansas, Inc.'s 100% interest in Robert Ritchie 1 and its 40.74% interest in Common Plant.

Schedule Page: 402.2 Line No.: 1 Column: b

Ouachita 1 & 2

Reflects Entergy Arkansas, Inc.'s 100% interest in Ouachita Units 1 & 2 and its 66.7% interest in Common Plant.

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: Carpenter (b)	FERC Licensed Project No. 0 Plant Name: Remmel (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Outdoor
3	Year Originally Constructed	1932	1923
4	Year Last Unit was Installed	1933	1923
5	Total installed cap (Gen name plate Rating in MW)	56.00	9.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	62	27
7	Plant Hours Connect to Load	3,664	4,959
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	59	11
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	101,163,000	29,446,004
13	Cost of Plant		
14	Land and Land Rights	1,060,395	244,068
15	Structures and Improvements	1,726,845	1,115,785
16	Reservoirs, Dams, and Waterways	5,125,120	9,871,624
17	Equipment Costs	15,106,654	4,943,120
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	6,187	1,154
20	TOTAL cost (Total of 14 thru 19)	23,025,201	16,175,751
21	Cost per KW of Installed Capacity (line 20 / 5)	411.1643	1,797.3057
22	Production Expenses		
23	Operation Supervision and Engineering	155,420	141,065
24	Water for Power	105,136	97,274
25	Hydraulic Expenses	0	0
26	Electric Expenses	43	35,649
27	Misc Hydraulic Power Generation Expenses	206,932	107,376
28	Rents	15,210	10,333
29	Maintenance Supervision and Engineering	4,978	3,307
30	Maintenance of Structures	83,215	9,475
31	Maintenance of Reservoirs, Dams, and Waterways	279,911	141,061
32	Maintenance of Electric Plant	52,959	111,074
33	Maintenance of Misc Hydraulic Plant	6,807	166,281
34	Total Production Expenses (total 23 thru 33)	910,611	822,895
35	Expenses per net KWh	0.0090	0.0279

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Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Cecil Lynch (Internal Combustion)	1967	6.00			1,485
2						
3						
4						
5						
6						
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8						
9						
10						
11						
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GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
248			-33,988	Oil		1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
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						46

Schedule Page: 410 Line No.: 1 Column: a

Cecil Lynch diesel unit was retired in 2013.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	White Bluff	Keo 6010	500.00		Lat Stl A	17.25		1
2	El Dorado	LA St Ln (Scec) 6004	500.00		Lat Stl A	24.31		1
3	Dell	Miss River 6019	500.00		Lat Stl A	28.39		1
4	Dell	Mo St Lin 6012	500.00		Lat Stl A	9.61		1
5	Hot Springs	McNeil 6014	500.00		Guyed Ste	84.15		1
6	El Dorado	McNeil 6013	500.00		Guyed Ste	37.76		1
7	Independence	Dell 6015	500.00		Lat Stl A	82.85		1
8	Independence	Keo 6016	500.00		Lat Stl A	64.10		1
9	White Bluff	Sheridan 6011	500.00		Lat Stl A	18.63		1
10	ANO	Mayflower 6002	500.00		Lat Stl A	60.88		1
11	Mabelvale-LR Pinnicle	Mayflower 6007	500.00		Lat Stl A	29.91		1
12	ANO	Jct Mablv 6001	500.00		Guyed Alu	49.03		2
13	El Dorado	La St Ln (Gsu) 6003	500.00		Lat Stl A	20.21		1
14	West Memphis	Mabelvale 6009	500.00		Lat Stl A	136.30		1
15	Miss River	West Memphis 6008	500.00		Lat Stl A	0.95		1
16	Jct Mablv	OG&E Connection 6006	500.00		Lat Stl A	84.94		1
17	Mabelvale	El Dorado 6005	500.00		Lat Stl A	95.34		1
18	Sheridan	Hot Springs 6017	500.00		Guyed Ste	26.80		1
19	Holland Bottom	KEO 0806	500.00		Lat Stl A	22.21		1
20	500kv Tie Lines		500.00		Lat Stl A	0.37		
21		Total 500kv Lines						
22								
23	El Dorado	LA State Line 6101	345.00		Guyed Alu	44.00		1
24		Total 345kv Lines						
25								
26	Lake Village Bagby	Miss St Line 6201	230.00		Wood H-Fr	14.07		1
27	Ritch-Wdwrd	Stuttg Ricuskey Tap 6205	230.00		DC Lat St	17.74		1
28	Ritchie	Miss River 6203	230.00		DC Lat St	1.30		1
29	Ritchie	Brinkley 6202	230.00		Wood H-Fr	44.84		1
30	Ritchie	Woodward 6204	230.00		DC Lat St	80.20	8.91	1
31	Ritchie	Miss River (#2) 6206	230.00		DC Lat St	1.54		1
32		Total 230kv Lines						
33								
34	Thayer South	AR/MO State Line 6368	161.00		Wood H-Fr	0.66		1
35	Rector	AR/MO State Line 6347	161.00		Wood H-Fr	17.57		1
36					TOTAL	4,670.79	158.26	209

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Monette Jct	Paragould 6345	161.00		Wood H-Fr	16.64		1
2	Blytheville Elm St	Dell-Monette Jct 6344	161.00		Wood H-Fr	23.69		1
3	Blytheville Elm St	Bly. Gen. Sta. 6343	161.00		Wood H-Fr	0.59		1
4	Blytheville Elm St	Crooked Lake 6373	161.00		Sng Concr	11.04		1
5	Blytheville Elm St	AR/MO State LIne 6342	161.00		Wood H-Fr	6.24		1
6	Blytheville Elm St	Osceola 6341	161.00		Wood H-Fr	12.12	5.02	1
7	Cushman	Cave City 6369	161.00		Wood H-Fr	9.61		1
8	Walnut Ridge	Alicia 6348	161.00		Wood H-Fr	3.50		1
9	Walnut Ridge	AR/MO State Line 6367	161.00		Wood H-Fr	48.74		1
10	Pocahontas	Datto 6362	161.00		Wood H-Fr	17.56		1
11	Water Valley	Pocahontas 6365	161.00		Wood H-Fr	5.90		1
12	Hayti	Noranda Gen Station 6352	161.00		Wood H-Fr	27.91		1
13	Hayti	AR/MO State Line 6350	161.00		Wood H-Fr	18.03		1
14	Hayti	Jim Hill Plant 6351	161.00		Wood H-Fr	26.72		1
15	Jim Hill Plant	AR/MO State Line 6353	161.00		Wood H-Fr	1.63		1
16	Crooked Lake	Barfield 6358	161.00		Sng Con P	0.60		1
17	Bull Shoals Sub	Bull Shoals Dam 6370	161.00		Sng Wood	0.57		1
18	Morrilton East	Russellville East 6323	161.00		Wood H-Fr	25.28		1
19	Moses	Parkin/Wynne Indl Tap 6328	161.00		Wood H-Fr	3.85		1
20	Rector	Paragould 6346	161.00		Wood H-Fr	26.67		1
21	LR Pinnacle	Morrilton East 6321	161.00		Wood H-Fr	40.67		1
22	Ebony	Market Tree 6340	161.00		Wood H-Fr	25.92		1
23	Brinkley	Moses 6305	161.00		Wood H-Fr	16.64		1
24	Conway West	Hamlet 6306	161.00		Wood H-Fr	14.31		1
25	Danville	Russellville East 6308	161.00		Wood H-Fr	26.22		1
26	Dell EHV	Jct Blyvl/Osceola 6366	161.00		DC Lat St	5.24	5.02	1
27	Jonesboro	Parkin 6317	161.00		Wood H-Fr	47.31	4.48	1
28	Moses-Newport	(Augusta Taps) 6325	161.00		Wood H-Fr	15.37		1
29	Moses	West Memphis 6329	161.00		Wood H-Fr	43.10		1
30	Moses	Newport 6324	161.00		Wood H-Fr	54.57		1
31	Moses	Parkin 6326	161.00		Wood H-Fr	32.33		1
32	Newport	ARKMO Conn. 6330	161.00		Wood H-Fr	31.73		1
33	Newport	Jonesboro-HRKMO 6333	161.00		Wood H-Fr	49.70		1
34	Newport	Parkin 6334	161.00		Wood H-Fr	47.84		1
35	Parking	Osceola 6337	161.00		Wood H-Fr	42.95		1
36					TOTAL	4,670.79	158.26	209

Name of Respondent Entergy Arkansas, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

TRANSMISSION LINE STATISTICS

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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Marked Tree	Lepanto 6322	161.00		Wood H-Fr	9.02		1
2	Moses	Parkin (F City N Tap) 6327	161.00		Wood H-Fr	2.69		1
3	Parkin	Kunh Road 6338	161.00		Wood H-Fr	18.88		1
4	Harrison East	SWEPCO Conn. 6314	161.00		Wood H-Fr	40.16		1
5	Hamlet-Hb Spgs S-Gr Fry	(Greenbrair Tap) 6311	161.00		Wood H-Fr	11.98		1
6	Jonesboro	SPA Inter 6320	161.00		Wood H-Fr	0.83		1
7	ISES	Jct Newport/Searcy Pr 6315	161.00		DC Lat St	8.71	7.98	1
8	Osceola	Osceola Industrial 6336	161.00		Wood H-Fr	2.02		1
9	Jonesboro	Parkin (JCW & LHRGT) 6319	161.00		Wood H-Fr	9.04		1
10	ISES/Rutrfd/S. Sude/	Pang/Searcy 6316	161.00		Wood H-Fr	72.06		1
11	Newport	Searcy Price 6361	161.00		Wood H-Fr	28.03	7.98	1
12	Parkin	WM WM Gateway Tap 6339	161.00		Wood H-Fr	6.30		1
13	ANO	Russellville East 6302	161.00		Wood H-Fr	10.21	1.71	1
14	Batesville	Norfork (Mt View Tap) 6304	161.00		Wood H-Fr	21.03		1
15	Conway West	Morrilton East 6307	161.00		Wood H-Fr	15.26		1
16	Batesville	Norfork 6303	161.00		Wood H-Fr	48.75		1
17	Danville Sub Sta	Tie Lns 6309	161.00		Wood H-Fr	0.03		1
18	Hamlet SW	Heber Springs/Grs Fry 6310	161.00		Wood H-Fr	35.21		1
19	Harrison East	Quitman 6313	161.00		Wood H-Fr	80.40		1
20	Gold Creek SW State Line	Sylvan Hills 6312	161.00		Wood H-Fr	19.60		1
21	Newport	Batesville (via ISES) 6331	161.00		Wood H-Fr	19.67	7.77	1
22	Norfork	Ozk Bch (B: SHLS Tap) 6335	161.00		Wood H-Fr	78.59		1
23	Jonesboro	Parkin (Hrsbrg Tap) 6318	161.00		Wood H-Fr	18.17		1
24	ANO	Morrilton East 6301	161.00		Wood H-Fr	39.37		1
25	ISES	NEWPORT #3 6716	161.00		Sng Concr	11.28		1
26	Pleasant Hill	Quitman 6371	161.00		Sng Concr	20.29		1
27	Grandview	Osage Creek 0874	161.00		Sng Concr	5.21		1
28	West Memphis	Ebony 0810	161.00		Sng Concr	8.78		1
29	Ebony SS	Kuhn Road 0811	161.00		Sng Concr	2.43		1
30	West Memphis	Ebony 0812	161.00		Sng Concr	6.45		1
31	Osage Creek	Tbl Rock - Beaver 6906	161.00		Sng Concr	1.18		1
32	Bald Knob	Tetc P Sta # 6 6652	161.00		Wood H-Fr	1.62		1
33	161kv Tie Lines		161.00		VARIOUS	51.16		
34		Total 161kv Lines						
35								
36					TOTAL	4,670.79	158.26	209

Name of Respondent Entergy Arkansas, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1		Total 115			Various	2,002.04	109.39	110
2		Arklahoma - Danville				56.70		1
3		(Leased)						
4								
5		Total 69k			Wood H-Fr	10.94		2
6								
7	Transmission Lines							
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
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21								
22								
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24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	4,670.79	158.26	209

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
954 ACSR								1
954 ACSR								2
954 ACSR								3
954 ACSR								4
954 ACSR								5
954 ACSR								6
954 ACSR								7
954 ACSR								8
954 ACSR								9
954 ACSR								10
954 ACSR								11
954 ACSR								12
954 ACSR								13
954 ACSR								14
954 ACSR								15
954 ACSR								16
954 ACSR								17
954 ACSR								18
954 ACSR								19
954 ACSR								20
	35,078,464	248,591,661	283,670,125					21
								22
1024.5 ACAR								23
	523,116	2,733,427	3,256,543					24
								25
1534 ACAR								26
1272 ACSR								27
3070 AACSR								28
1534 ACAR								29
1272 ACSR								30
3070 AACSR								31
	1,802,287	33,678,740	35,481,027					32
								33
666 ACSR								34
336 ACSR								35
	83,250,549	767,387,551	850,638,100	13,627,961	4,313,552	58,293	17,999,806	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
336 ACSR								1
336 ACSR								2
1272 ACSR								3
954 ACSR								4
336 ACSR								5
1590 ACSR								6
666 ACSR								7
636 ACSR								8
666 ACSR								9
1590 ACSR								10
1590 ACSR								11
1272 ACSR								12
336 ACSR								13
336 ACSR								14
336 ACSR								15
954 ACSR								16
666 ACSR								17
1534 ACAR								18
336 ACSR								19
336 ACSR								20
666 ACSR								21
666 ACSR								22
954 ACSR								23
666 ACSR								24
666 ACSR								25
1590 ACSR								26
336 ACSR								27
666 ACSR								28
336 ACSR								29
336 ACSR								30
336 ACSR								31
666 ACSR								32
336 ACSR								33
666 ACSR								34
336 ACSR								35
	83,250,549	767,387,551	850,638,100	13,627,961	4,313,552	58,293	17,999,806	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
666 ACSR								1
336 ACSR								2
666 ACSR								3
666 ACSR								4
666 ACSR								5
666 ACSR								6
1590 ACSR								7
666 ACSR								8
1534 ACAR								9
666 ACSR								10
1590 ACSR								11
336 ACSR								12
1534 ACAR								13
336 ACSR								14
666 ACSR								15
336 ACSR								16
666 ACSR								17
666 ACSR								18
666 ACSR								19
666 ACSR								20
1590 ACSR								21
250 CU								22
666 ACSR								23
1024 ACAR								24
1590 ACSR								25
954 ACSR								26
666 ACSS								27
666 ACSS								28
666 ACSS								29
666 ACSS								30
666 ACSR								31
666 ACSR								32
VARIOUS								33
	17,007,605	230,091,394	247,098,999					34
								35
	83,250,549	767,387,551	850,638,100	13,627,961	4,313,552	58,293	17,999,806	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
	28,763,244	251,798,747	280,561,991					1
								2
								3
								4
	75,833	493,582	569,415					5
								6
				13,627,961	4,313,552	58,293	17,999,806	7
								8
								9
								10
								11
								12
								13
								14
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								34
								35
	83,250,549	767,387,551	850,638,100	13,627,961	4,313,552	58,293	17,999,806	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From	To		Type	Average Number per Miles	Present	Ultimate
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Hamlet	Holland Bottom	21.20	Steel/Concr	8.35	1	
44	TOTAL		21.20		8.35	1	

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TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS Size (h)	CONDUCTORS Specification (i)	CONDUCTORS Configuration and Spacing (j)	Voltage KV (Operating) (k)	LINE COST Land and Land Rights (l)	LINE COST Poles, Towers and Fixtures (m)	LINE COST Conductors and Devices (n)	LINE COST Asset Retire. Costs (o)	LINE COST Total (p)	Line No.
666	ACSS	VERTICAL	161	9,288,058	11,947,869	3,553,478	3,553,479	28,342,884	1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
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									37
									38
									39
									40
									41
									42
									43
				9,288,058	11,947,869	3,553,478	3,553,479	28,342,884	44

Name of Respondent Entergy Arkansas, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	 Secondary (d)	 Tertiary (e)
1	ALCOA ROAD	Distrib. Unattended	115.00	13.80	
2	ALMYRA	Distrib. Unattended	115.00	13.80	
3	ALTHEIMER	Distrib. Unattended	115.00	13.80	
4	AMITY	Distrib. Unattended	115.00	13.80	
5	ANTOINE	Distrib. Unattended	34.50	12.40	
6	ARKADELPHIA NORTH	Distrib. Unattended	115.00	13.80	
7	ARKADELPHIA WEST	Distrib. Unattended	115.00	13.80	
8	ARKLAHOMA	Distrib. Unattended	115.00	13.80	
9	ARMOREL	Distrib. Unattended	34.50	12.40	
10	ATKINS	Distrib. Unattended	161.00	13.80	
11	BALD KNOB	Distrib. Unattended	161.00	13.80	
12	BARTON	Distrib. Unattended	115.00	13.80	
13	BATESVILLE (APL)	Distrib. Unattended	161.00	13.80	
14	BAUCUM	Distrib. Unattended	115.00	13.80	
15	BAUXITE	Distrib. Unattended	115.00	13.80	
16	BEARDEN	Distrib. Unattended	115.00	13.80	
17	BEEBE	Distrib. Unattended	115.00	13.80	
18	BEIRNE	Distrib. Unattended	115.00	13.80	
19	BENTON NORTH	Distrib. Unattended	115.00	13.80	
20	BENTON SOUTH	Distrib. Unattended	115.00	13.80	
21	BERRYVILLE	Distrib. Unattended	161.00	13.80	
22	BIGGERS	Distrib. Unattended	34.50	4.80	
23	BISMARCK	Distrib. Unattended	115.00	13.80	
24	BLACK OAK	Distrib. Unattended	34.50	12.40	
25	BLACK ROCK	Distrib. Unattended	34.50	12.40	
26	BLYTHEVILLE AFB	Distrib. Unattended	34.50	12.40	
27	BLYTHEVILLE EAST END	Distrib. Unattended	34.50	12.40	
28	BLYTHEVILLE ELM ST.	Distrib. Unattended	161.00	12.40	
29	BLYTHEVILLE FLAT LAKE	Distrib. Unattended	34.50	12.40	
30	BLYTHEVILLE I-55	Distrib. Unattended	161.00	34.50	
31	BLYTHEVILLE PLANT	Distrib. Unattended	34.50	4.80	
32	BLYTHEVILLE N.EAST	Distrib. Unattended	34.50	12.40	
33	BLYTHEVILLE N.WEST	Distrib. Unattended	34.50	12.40	
34	BLYTHEVILLE S.WEST	Distrib. Unattended	34.50	12.40	
35	BRINKLEY EAST	Distrib. Unattended	115.00	13.80	
36	BRINKLEY WEST	Distrib. Unattended	115.00	13.80	
37	BRYANT	Distrib. Unattended	115.00	13.80	
38	BULL SHOALS	Distrib. Unattended	161.00	13.80	
39	BUTLER HALL, 4470	Distrib. Unattended	34.50	12.40	
40	BUTTERFIELD	Distrib. Unattended	115.00	13.80	

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Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CABOT (APL)	Distrib. Unattended	115.00	13.80	
2	CALICO ROCK	Distrib. Unattended	161.00	13.80	
3	CAMDEN MAGUIRE	Distrib. Unattended	115.00	13.80	
4	CAMDEN NORTH	Distrib. Unattended	115.00	13.80	
5	CAMPBELL	Distrib. Unattended	34.50	12.40	
6	CARLISLE (APL)	Distrib. Unattended	115.00	13.80	
7	CARPENTER DAM	Distrib. Unattended	115.00	13.80	
8	CARTHAGE (APL)	Distrib. Unattended	115.00	13.80	
9	CASH	Distrib. Unattended	161.00	13.80	
10	CAVE CITY	Distrib. Unattended	161.00	34.50	
11	CEDAR GROVE	Distrib. Unattended	161.00	13.80	
12	CHERRY VALLEY	Distrib. Unattended	161.00	13.80	
13	CLARENDON	Distrib. Unattended	115.00	13.80	
14	CLINTON (APL)	Distrib. Unattended	161.00	13.80	
15	COLLEGE CITY	Distrib. Unattended	34.50	12.40	
16	CONWAY INDUSTRIAL CO	Distrib. Unattended	161.00	13.80	
17	CONWAY SOUTH CO	Distrib. Unattended	161.00	13.80	
18	CONWAY WEST CO	Distrib. Unattended	161.00	13.80	
19	CORNING 115	Distrib. Unattended	115.00	34.50	
20	CORNING 34.5	Distrib. Unattended	34.50	12.40	
21	COTTON PLANT	Distrib. Unattended	115.00	13.80	
22	COTTON PLANT CITY 4160	Distrib. Unattended	13.80	4.80	
23	COUCH SES SWITCHYARD	Distrib. Unattended	115.00	13.80	
24	CROOKED LAKE	Distrib. Unattended	161.00	34.50	
25	CROSSETT NORTH	Distrib. Unattended	115.00	13.80	
26	CROSSETT PAPER MILL	Distrib. Unattended	115.00	13.80	
27	CROSSETT WEST	Distrib. Unattended	115.00	13.80	
28	CUSHMAN	Distrib. Unattended	161.00	13.80	
29	DALARK	Distrib. Unattended	115.00	34.50	
30	DANVILLE (APL)	Distrib. Unattended	161.00	13.80	
31	DARDANELLE	Distrib. Unattended	161.00	13.80	
32	DATTO	Distrib. Unattended	115.00	2.40	
33	DELIGHT	Distrib. Unattended	34.50	13.80	
34	DELL CITY	Distrib. Unattended	34.50	2.40	
35	DERMOTT	Distrib. Unattended	115.00	13.80	
36	DES ARC	Distrib. Unattended	115.00	13.80	
37	DEVALLS BLUFF	Distrib. Unattended	115.00	13.80	
38	DEWITT	Distrib. Unattended	115.00	13.80	
39	DIAMOND CITY	Distrib. Unattended	34.50	13.80	
40	DUMAS	Distrib. Unattended	115.00	13.80	

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	EL DORADO DONAN	Distrib. Unattended	115.00	13.80	
2	EL DORADO EAST	Distrib. Unattended	115.00	13.80	
3	EL DORADO JACKSON	Distrib. Unattended	115.00	13.80	
4	EL DORADO LION OIL	Distrib. Unattended	115.00	13.80	
5	EL DORADO MILL ROAD	Distrib. Unattended	115.00	13.80	
6	EL DORADO MONSANTO	Distrib. Unattended	115.00	13.80	
7	EL DORADO NEWELL	Distrib. Unattended	115.00	13.80	
8	EL DORADO PARKERS CHAPEL	Distrib. Unattended	115.00	13.80	
9	EL DORADO PARNELL ROAD	Distrib. Unattended	115.00	13.80	
10	EL DORADO QUINN	Distrib. Unattended	115.00	13.80	
11	EL DORADO UPLAND	Distrib. Unattended	115.00	13.80	
12	EL DORADO WEST	Distrib. Unattended	115.00	13.80	
13	ELAINE	Distrib. Unattended	115.00	13.80	
14	EMERSON	Distrib. Unattended	115.00	13.80	
15	ENGLAND	Distrib. Unattended	115.00	13.80	
16	EUDORA	Distrib. Unattended	161.00	34.50	
17	EVERTON ROAD	Distrib. Unattended	161.00	13.80	
18	FAULKNER LAKE (NLR)	Distrib. Unattended	115.00	13.80	
19	FISHER	Distrib. Unattended	161.00	13.80	
20	FLIPPIN	Distrib. Unattended	161.00	13.80	
21	FORDYCE	Distrib. Unattended	115.00	13.80	
22	FORDYCE ORIENT	Distrib. Unattended	115.00	13.80	
23	FORREST CITY NORTH	Distrib. Unattended	161.00	13.80	
24	FORREST CITY SOUTH	Distrib. Unattended	161.00	13.80	
25	FOUNTAIN LAKE	Distrib.Unattended	115.00	13.80	
26	FRIENDSHIP	Distrib. Unattended	115.00	13.80	
27	GIFFORD	Distrib. Unattended	115.00	13.80	
28	GILLETT	Distrib. Unattended	115.00	13.80	
29	GILMORE	Distrib. Unattended	161.00	13.80	
30	GLEASON	Distrib. Unattended	161.00	13.80	
31	GLENWOOD	Distrib. Unattended	115.00	13.80	
32	GLENWOOD PUMPING PLANT	Distrib. Unattended	13.80	2.40	
33	GREEN FOREST	Distrib. Unattended	161.00	13.80	
34	GREEN FOREST SOUTH	Distrib. Unattended	161.00	13.80	
35	GREENBRIER	Distrib. Unattended	161.00	13.80	
36	GREENWAY	Distrib. Unattended	34.50	4.80	
37	GRIFFITHVILLE	Distrib. Unattended	115.00	13.80	
38	GUION	Distrib. Unattended	161.00	13.80	
39	GURDON	Distrib. Unattended	115.00	13.80	
40	H.S. EAST	Distrib. Unattended	115.00	13.80	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	H.S. INDUSTRIAL	Distrib. Unattended	115.00	13.80	
2	H.S. MILTON	Distrib. Unattended	115.00	13.80	
3	H.S. MT. VALLEY	Distrib. Unattended	115.00	13.80	
4	H.S. NORTH	Distrib. Unattended	115.00	13.80	
5	H.S. ROYAL	Distrib. Unattended	115.00	13.80	
6	H.S. SOUTH	Distrib. Unattended	115.00	13.80	
7	H.S. UNION CARBIDE	Distrib. Unattended	115.00	13.80	
8	H.S. VALLEY STREET	Distrib. Unattended	115.00	13.80	
9	H.S. VILLAGE	Distrib. Unattended	115.00	13.80	
10	H.S. WEST	Distrib. Unattended	115.00	13.80	
11	HAMBURG	Distrib. Unattended	115.00	13.80	
12	HAMLET	Distrib. Unattended	161.00	2.40	
13	HARDIN WEST	Distrib. Unattended	115.00	13.80	
14	HARDY NORTH	Distrib. Unattended	161.00	13.80	
15	HARRISBURG	Distrib. Unattended	161.00	13.80	
16	HARRISON EAST	Distrib. Unattended	161.00	13.80	
17	HARRISON WEST	Distrib. Unattended	161.00	13.80	
18	HASKELL	Distrib. Unattended	115.00	13.80	
19	HAYS CITY	Distrib. Unattended	115.00	13.80	
20	HAZEN	Distrib. Unattended	115.00	13.80	
21	HEBER SPRINGS INDUSTRIAL	Distrib. Unattended	161.00	13.80	
22	HEBER SPRINGS SOUTH	Distrib. Unattended	161.00	13.80	
23	HELENA CENTRAL	Distrib. Unattended	115.00	13.80	
24	HELENA SOUTH	Distrib. Unattended	115.00	13.80	
25	HENSLEY	Distrib. Unattended	115.00	13.80	
26	HERMITAGE (APL)	Distrib. Unattended	115.00	13.80	
27	HIGHLAND (APL)	Distrib. Unattended	161.00	13.80	
28	HIGHWAY #7	Distrib. Unattended	34.50	13.80	
29	HILO	Distrib. Unattended	115.00	13.80	
30	HUGHES	Distrib. Unattended	161.00	13.80	
31	HUTTIG	Distrib. Unattended	115.00	13.80	
32	IMBODEN	Distrib. Unattended	69.00	34.50	
33	IMBODEN JUNCTION	Distrib. Unattended	34.50	12.40	
34	INDEPENDENCE-ISES-SWITCHYARD	Distrib. Unattended	161.00	13.80	
35	JACKSONVILLE NORTH	Distrib. Unattended	115.00	13.80	
36	JACKSONVILLE SOUTH	Distrib. Unattended	115.00	13.80	
37	JIM HILL	Distrib. Unattended	115.00	34.50	
38	JONESBORO (APL)	Distrib. Unattended	161.00	13.80	
39	KERLIN	Distrib. Unattended	115.00	13.80	
40	KINGSLAND	Distrib. Unattended	115.00	13.80	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	KUHN ROAD	Distrib. Unattended	161.00	13.80	
2	L.R. 145TH ST	Distrib. Unattended	115.00	13.80	
3	L.R. 23RD & SPRING	Distrib. Unattended	115.00	13.80	
4	L.R. 8TH & WOODROW	Distrib. Unattended	115.00	13.80	
5	L.R. ALEXANDER	Distrib. Unattended	115.00	13.80	
6	L.R. ARCH ST.	Distrib. Unattended	115.00	13.80	
7	L.R. BOYLE PARK	Distrib. Unattended	115.00	13.80	
8	L.R. BRINGLE	Distrib. Unattended	161.00	13.80	
9	L.R. CAMMACK	Distrib. Unattended	115.00	13.80	
10	L.R. CHICOT	Distrib. Unattended	115.00	13.80	
11	L.R. EAST	Distrib. Unattended	115.00	13.80	
12	L.R. FOURCHE	Distrib. Unattended	115.00	13.80	
13	L.R. GAINES	Distrib. Unattended	115.00	13.80	
14	L.R. GARLAND	Distrib. Unattended	115.00	13.80	
15	L.R. HINDMAN	Distrib. Unattended	115.00	13.80	
16	L.R. INDUSTRIAL	Distrib. Unattended	115.00	13.80	
17	L.R. KANIS RD	Distrib. Unattended	115.00	13.80	
18	L.R. MANN	Distrib. Unattended	115.00	13.80	
19	L.R. PINNACLE	Distrib. Unattended	115.00	13.80	
20	L.R. PORT	Distrib. Unattended	115.00	13.80	
21	L.R. ROCK CREEK	Distrib. Unattended	115.00	13.80	
22	L.R. ROLAND ROAD	Distrib. Unattended	115.00	13.80	
23	L.R. SOUTH	Distrib. Unattended	115.00	13.80	
24	L.R. WALTON HEIGHTS	Distrib. Unattended	115.00	13.80	
25	L.R. WEST	Distrib. Unattended	115.00	13.80	
26	L.R. WEST MARKHAM	Distrib. Unattended	115.00	13.80	
27	LAKE CHICOT PUMP STA	Distrib. Unattended	115.00	4.80	
28	LAKE CONWAY	Distrib. Unattended	115.00	13.80	
29	LAKE VILLAGE BAGBY	Distrib. Unattended	115.00	13.80	
30	LAKEWOOD (NLR)	Distrib. Unattended	115.00	13.80	
31	LAMARTINE	Distrib. Unattended	115.00	13.80	
32	LEACHVILLE	Distrib. Unattended	34.50	12.40	
33	LEPANTO	Distrib. Unattended	161.00	13.80	
34	LEWISVILLE	Distrib. Unattended	115.00	13.80	
35	LONDON	Distrib. Unattended	161.00	13.80	
36	LONOKE EAST	Distrib. Unattended	115.00	13.80	
37	LUNSFORD	Distrib. Unattended	69.00	13.80	
38	MABELVALE EHV	Distrib. Unattended	115.00	13.80	
39	MAGNOLIA DOW	Distrib. Unattended	115.00	13.80	
40	MAGNOLIA EAST	Distrib. Unattended	115.00	13.80	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	MAGNOLIA SOUTH	Distrib. Unattended	115.00	13.80	
2	MAGNOLIA STEEL	Distrib. Unattended	115.00	13.80	
3	MAGNOLIA WEST	Distrib. Unattended	115.00	13.80	
4	MALVERN NORTH	Distrib. Unattended	115.00	13.80	
5	MALVERN SOUTH	Distrib. Unattended	115.00	13.80	
6	MANILA	Distrib. Unattended	34.50	12.40	
7	MANSON 34.5	Distrib. Unattended	34.50	2.40	
8	MARIANNA	Distrib. Unattended	115.00	13.80	
9	MARION	Distrib. Unattended	161.00	13.80	
10	MARKED TREE	Distrib. Unattended	161.00	13.80	
11	MARMADUKE	Distrib. Unattended	34.50	12.40	
12	MARMADUKE ARI	Distrib. Unattended	34.50	12.40	
13	MARMADUKE RAIL 161KV	Distrib. Unattended	161.00	34.50	
14	MARSHALL	Distrib. Unattended	161.00	13.80	
15	MARVELL	Distrib. Unattended	115.00	13.80	
16	MAUMELLE EAST	Distrib. Unattended	115.00	13.80	
17	MCALMONT	Distrib. Unattended	115.00	13.80	
18	MCCRORY	Distrib. Unattended	161.00	13.80	
19	MCGEHEE	Distrib. Unattended	115.00	13.80	
20	MCNEIL EHV	Distrib. Unattended	115.00	13.80	
21	MELBOURNE	Distrib. Unattended	161.00	13.80	
22	MONETTE	Distrib. Unattended	34.50	12.40	
23	MONETTE JUNCTION	Distrib. Unattended	161.00	34.50	
24	MONTICELLO EAST	Distrib. Unattended	115.00	13.80	
25	MONTICELLO SOUTH	Distrib. Unattended	115.00	13.80	
26	MONTROSE	Distrib. Unattended	115.00	13.80	
27	MOOREFIELD	Distrib. Unattended	161.00	13.80	
28	MORELAND	Distrib. Unattended	161.00	13.80	
29	MORGAN	Distrib. Unattended	115.00	13.80	
30	MORO	Distrib. Unattended	115.00	13.80	
31	MORRILTON EAST	Distrib. Unattended	161.00	13.80	
32	MORRILTON WEST	Distrib. Unattended	161.00	13.80	
33	MOUNT PLEASANT	Distrib. Unattended	161.00	13.80	
34	MOUNTAIN HOME	Distrib. Unattended	161.00	13.80	
35	MOUNTAIN VIEW	Distrib. Unattended	161.00	13.80	
36	MT IDA	Distrib. Unattended	115.00	13.80	
37	MT PINE NORTH	Distrib. Unattended	115.00	13.80	
38	MT PINE SOUTH	Distrib. Unattended	115.00	13.80	
39	N.L.R. DIXIE	Distrib. Unattended	115.00	13.80	
40	N.L.R. LEVY	Distrib. Unattended	115.00	13.80	

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1	N.L.R. MCCAIN	Distrib. Unattended	115.00	13.80	
2	N.L.R. WESTGATE	Distrib. Unattended	115.00	13.80	
3	NEWARK	Distrib. Unattended	161.00	13.80	
4	NEWPORT	Distrib. Unattended	161.00	13.80	
5	NEWPORT AB	Distrib. Unattended	161.00	13.80	
6	NEWPORT IND	Distrib. Unattended	161.00	13.80	
7	OLA	Distrib. Unattended	115.00	13.80	
8	OMAHA	Distrib. Unattended	161.00	13.80	
9	OSCEOLA	Distrib. Unattended	161.00	13.80	
10	OSCEOLA INDUSTRIAL	Distrib. Unattended	161.00	13.80	
11	OSCEOLA NORTH	Distrib. Unattended	161.00	13.80	
12	P.B. 34TH & MAIN	Distrib. Unattended	115.00	13.80	
13	P.B. ARSENAL D	Distrib. Unattended	115.00	13.80	
14	P.B. DIERKS	Distrib. Unattended	115.00	13.80	
15	P.B. EAST	Distrib. Unattended	115.00	13.80	
16	P.B. INDUSTRIAL	Distrib. Unattended	115.00	13.80	
17	P.B. MCCAMANT	Distrib. Unattended	115.00	13.80	
18	P.B. PORT	Distrib. Unattended	115.00	13.80	
19	P.B. SOUTH	Distrib. Unattended	115.00	13.80	
20	P.B. WATSON CHAPEL	Distrib. Unattended	115.00	13.80	
21	P.B. WEST	Distrib. Unattended	115.00	13.80	
22	P.B. WHITEHALL	Distrib. Unattended	115.00	13.80	
23	PANGBURN	Distrib. Unattended	161.00	13.80	
24	PARAGOULD	Distrib. Unattended	115.00	12.40	
25	PARKIN	Distrib. Unattended	161.00	13.80	
26	POCAHONTAS NORTH	Distrib. Unattended	161.00	12.40	
27	POCAHONTAS SOUTH	Distrib. Unattended	34.50	12.40	
28	PORTIA	Distrib. Unattended	34.50	2.40	
29	POYEN	Distrib. Unattended	115.00	13.80	
30	PRESCOTT	Distrib. Unattended	115.00	13.80	
31	PROMISED LAND	Distrib. Unattended	34.50	12.40	
32	QUITMAN	Distrib. Unattended	161.00	13.80	
33	RECTOR	Distrib. Unattended	161.00	12.40	
34	REYNO	Distrib. Unattended	34.50	4.80	
35	RICHWOOD	Distrib. Unattended	115.00	13.80	
36	RISON	Distrib. Unattended	115.00	13.80	
37	RITCHIE SES PLANT	Distrib. Unattended	230.00	13.80	
38	ROHWER	Distrib. Unattended	115.00	13.80	
39	RUSSELLVILLE EAST	Distrib. Unattended	161.00	13.80	
40	RUSSELLVILLE NORTH	Distrib. Unattended	161.00	13.80	

Name of Respondent Entergy Arkansas, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

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1	RUSSELLVILLE SOUTH	Distrib. Unattended	161.00	13.80	
2	RUTHERFORD	Distrib. Unattended	161.00	13.80	
3	SC LITTLE ROCK	Distrib. Unattended	34.50	12.40	
4	SEARCY PRICE	Distrib. Unattended	115.00	13.80	
5	SEARCY SOUTH	Distrib. Unattended	161.00	13.80	
6	SHERIDAN	Distrib. Unattended	115.00	13.80	
7	SHERRILL	Distrib. Unattended	115.00	13.80	
8	SHERWOOD	Distrib. Unattended	115.00	13.80	
9	SHOFFNER	Distrib. Unattended	161.00	13.80	
10	SHULER	Distrib. Unattended	115.00	13.80	
11	SMACKOVER	Distrib. Unattended	115.00	13.80	
12	SOUTH LEAD HILL	Distrib. Unattended	161.00	34.50	
13	SOUTHSIDE	Distrib. Unattended	161.00	13.80	
14	ST. FRANCIS	Distrib. Unattended	34.50	2.40	
15	ST. JOE	Distrib. Unattended	161.00	13.80	
16	ST. VINCENT	Distrib. Unattended	161.00	13.80	
17	STEPHENS	Distrib. Unattended	115.00	13.80	
18	STRAWBERRY	Distrib. Unattended	13.80	2.40	
19	STRONG	Distrib. Unattended	115.00	13.80	
20	STUTTGART INDUSTRIAL	Distrib. Unattended	115.00	13.80	
21	STUTTGART NORTH	Distrib. Unattended	115.00	13.80	
22	STUTTGART RICUSKEY	Distrib. Unattended	115.00	13.80	
23	SUMMIT	Distrib. Unattended	161.00	13.80	
24	SWIFTON	Distrib. Unattended	161.00	13.80	
25	TAYLOR	Distrib. Unattended	115.00	13.80	
26	THAYER NORTH	Distrib. Unattended	69.00	4.80	
27	TRUMANN	Distrib. Unattended	161.00	13.80	
28	TWIST	Distrib. Unattended	161.00	13.80	
29	ULM	Distrib. Unattended	115.00	13.80	
30	VARNER	Distrib. Unattended	115.00	13.80	
31	VILONIA	Distrib. Unattended	161.00	13.80	
32	WABBASEKA	Distrib. Unattended	115.00	13.80	
33	WALCOTT	Distrib. Unattended	34.50	12.40	
34	WALNUT RIDGE NORTH	Distrib. Unattended	34.50	12.40	
35	WALNUT RIDGE PLANT	Distrib. Unattended	34.50	12.40	
36	WALNUT RIDGE W/161	Distrib. Unattended	161.00	12.40	
37	WARREN EAST	Distrib. Unattended	115.00	13.80	
38	WARREN WEST	Distrib. Unattended	115.00	13.80	
39	WEST HELENA	Distrib. Unattended	115.00	13.80	
40	WEST MEMPHIS DOVER	Distrib. Unattended	161.00	13.80	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WEST MEMPHIS GATEWAY	Distrib. Unattended	161.00	13.80	
2	WEST MEMPHIS LEHI	Distrib. Unattended	161.00	13.80	
3	WHELEN SPRINGS	Distrib. Unattended	34.50	12.40	
4	WHITE BLUFF EHV	Distrib. Unattended	115.00	13.80	
5	WILMAR	Distrib. Unattended	115.00	13.80	
6	WILMOT	Distrib. Unattended	34.50	13.80	
7	WILSON	Distrib. Unattended	161.00	13.80	
8	WOODWARD	Distrib. Unattended	115.00	13.80	
9	WYNNE CITY 4160	Distrib. Unattended	13.80	4.80	
10	WYNNE INDUSTRIAL	Distrib. Unattended	161.00	13.80	
11	WYNNE SOUTH	Distrib. Unattended	161.00	13.80	
12	ANO SWITCHYARD	Trans Unattended	500.00	161.00	
13	BALD KNOB-TEXAS EASTERN T.C. P.S. #6 SS	Trans Unattended	161.00	115.00	
14	BRINKLEY EAST	Trans Unattended	230.00	115.00	
15	CONWAY WEST	Trans Unattended	161.00	115.00	
16	DANVILLE (APL)	Trans Unattended	161.00	115.00	
17	DATTO	Trans Unattended	161.00	115.00	
18	DELL EHV	Trans Unattended	500.00	161.00	
19	EL DORADO EHV	Trans Unattended	500.00	115.00	
20	H.S. EHV	Trans Unattended	500.00	115.00	
21	INDEPENDENCE-ISES	Trans Unattended	500.00	161.00	
22	JIM HILL	Trans Unattended	161.00	115.00	
23	L.R. PINNACLE	Trans Unattended	161.00	115.00	
24	LAKE VILLAGE BAGBY	Trans Unattended	230.00	115.00	
25	MABELVALE EHV	Trans Unattended	500.00	115.00	
26	MAYFLOWER EHV	Trans Unattended	500.00	115.00	
27	MCNEIL EHV	Trans Unattended	500.00	115.00	
28	MOSES SES	Trans. Unattended	161.00	115.00	
29	MURFREESBORO SOUTH	Trans Unattended	138.00	115.00	
30	PARAGOULD	Trans Unattended	161.00	115.00	
31	PLEASANT HILL	Trans Unattended	500.00	161.00	
32	RITCHIE SES SWITCHYARD	Trans Unattended	230.00	115.00	
33	SEARCY PRICE	Trans Unattended	161.00	115.00	
34	STUTTGART RICUSKEY	Trans Unattended	230.00	115.00	
35	SYLVAN HILLS	Trans Unattended	161.00	115.00	
36	THAYER SOUTH	Trans Unattended	161.00	69.00	
37	WALNUT RIDGE W/161	Trans Unattended	161.00	115.00	
38	WATER VALLEY	Trans Unattended	161.00	69.00	
39	WEST MEMPHIS EHV	Trans Unattended	500.00	161.00	
40	WHITE BLUFF EHV	Trans Unattended	500.00	115.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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1	WOODWARD	Trans Unattended	230.00	115.00	
2	WRIGHTSVILLE	Trans Unattended	500.00	115.00	
3	Total Capacity		48294.70	8290.50	
4					
5	Distribution Unattended 331				
6	Transmission Unattended 31				
7					
8	LEASED SUBSTATIONS				
9	MARKMAN FERRY - MARKMAN FERRY, OK	Trans. Unattended	161.00	115.00	
10	ARKLAHOMA "A" - JONES MILL, AR	Trans. Unattended	115.00	13.80	
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
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22					
23					
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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
67	2					1
10	1					2
13	1					3
23	2					4
2	3					5
30	1					6
30	1					7
20	1	1				8
18	2					9
40	2					10
34	1					11
7	1					12
93	3					13
13	1					14
25	1					15
13	1					16
34	1					17
17	1					18
34	1					19
30	1					20
53	2					21
1	3	1				22
13	1					23
5	1					24
3	1	6				25
30	3					26
11	1					27
87	3	1				28
4	1					29
75	2					30
23	2					31
18	2					32
18	2					33
11	1					34
26	2					35
33	1					36
34	1					37
20	1					38
2	1					39
13	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
53	2					1
10	1					2
20	1					3
53	2					4
13	1					5
20	1					6
33	1					7
13	1					8
22	1					9
14	1					10
7	1					11
20	1					12
13	1					13
20	1					14
11	1					15
83	2					16
84	2					17
100	2					18
37	1					19
15	2					20
7	1	1				21
	1					22
13	1					23
33	1					24
67	2					25
64	2					26
34	1					27
7	1					28
7	1					29
22	1					30
67	2					31
13	4					32
6	1					33
2	3					34
20	1					35
13	1					36
7	1					37
25	1					38
6	1					39
63	3					40

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
63	2					1
50	2					2
63	2					3
30	1					4
20	1					5
20	1					6
20	1					7
20	1					8
50	1					9
13	1					10
53	2					11
34	1					12
13	1					13
13	1					14
25	2					15
20	1					16
25	1					17
50	1					18
20	1					19
20	1					20
30	2					21
33	1					22
42	2					23
22	1					24
33	1					25
6	1					26
41	2					27
13	1					28
5	1					29
42	2					30
22	1					31
3	1					32
20	1					33
30	1					34
30	1					35
1	3					36
7	1					37
7	1					38
23	2					39
5	1					40

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
13	1					1
34	1					2
20	1					3
30	1					4
33	1					5
67	2					6
20	1					7
64	2					8
54	2					9
34	1					10
13	2					11
57	3					12
5	1					13
33	1					14
20	1					15
63	2					16
97	3					17
40	2					18
16	1					19
20	1					20
33	1					21
22	1					22
20	1					23
20	1					24
10	1					25
7	1					26
30	1					27
13	1					28
5	1					29
22	1					30
13	1					31
8	1					32
4	3					33
20	1					34
89	2					35
30	1					36
33	1	1				37
22	1					38
33	2					39
3	1					40

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
33	1					1
20	1					2
34	1					3
100	2					4
63	2					5
30	1					6
63	2					7
3	1					8
34	1					9
64	2					10
67	2					11
34	1					12
100	2					13
112	2					14
34	1					15
80	2					16
66	2					17
20	1					18
33	1					19
67	2					20
67	2					21
13	1					22
55	2					23
83	2					24
100	2					25
162	3					26
60	2					27
37	1					28
34	1					29
33	1					30
23	2					31
13	1					32
22	1					33
22	1					34
10	1					35
30	1					36
11	1					37
50	1	4				38
13	1					39
33	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
33	1					1
13	1					2
34	1					3
30	1					4
47	2					5
11	1					6
2	3					7
20	1					8
47	2					9
22	1					10
5	1	4				11
11	1					12
33	1					13
20	1					14
12	2					15
67	2					16
67	2					17
20	1					18
30	1					19
20	1					20
22	1					21
5	1					22
75	2					23
34	1					24
30	1					25
47	2					26
46	2					27
20	1					28
63	2					29
7	1					30
34	1					31
30	1					32
10	1					33
56	2					34
42	2					35
42	2					36
20	1					37
33	1					38
50	1	1				39
83	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
33	1					1
64	2					2
10	1					3
34	1					4
22	1					5
92	3					6
53	3					7
35	5					8
44	2					9
30	1					10
33	1					11
30	1					12
15	2					13
34	1					14
60	2					15
58	2					16
64	2					17
33	1					18
20	1					19
64	2					20
3	1					21
34	1					22
20	1					23
26	4					24
20	1					25
44	2					26
13	1					27
2	1	1				28
26	2	1				29
42	2					30
1	2					31
22	1					32
48	2					33
1	3					34
7	1					35
9	1					36
375	1					37
46	2					38
100	2					39
83	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
80	2					1
67	2					2
2	2	5				3
84	2					4
84	2					5
30	1					6
7	1					7
106	2					8
5	1					9
33	2					10
13	1					11
20	1					12
20	1					13
1	3					14
3	1					15
20	1					16
10	1					17
4	1					18
13	1					19
33	1					20
30	1					21
60	2					22
42	2					23
25	2					24
4	1					25
7	2					26
20	1					27
5	1					28
20	1					29
25	2					30
40	1					31
13	1					32
1	1					33
11	1					34
20	1					35
72	3					36
25	2					37
20	1					38
34	1					39
34	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
30	1					1
56	2					2
3	1					3
45	2					4
7	1					5
20	1					6
20	1					7
33	1	1				8
	1					9
45	2					10
20	1					11
896	4					12
50	1					13
616	3					14
224	1					15
125	1					16
225	1					17
672	3	1				18
1344	6	2				19
1100	2					20
850	2					21
112	1					22
225	1					23
448	1					24
895	6	2				25
1260	3					26
600	3	1				27
165	2					28
150	1					29
125	1					30
800	4					31
180	1					32
225	1					33
448	1					34
140	1					35
50	1					36
60	3	1				37
50	1					38
450	3	1				39
840	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
300	1					1
597	4					2
24972	540	36				3
						4
						5
						6
						7
						8
75	1					9
13	1					10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426 Line No.: 1 Column: a

These substations are jointly leased from the Arklahoma Corporation by Entergy Arkansas and other owners of this Corporation beginning December 9, 1947 and automatically renewed annually. Common stock of the Arklahoma Corporation is jointly owned by Entergy Arkansas (34%), Oklahoma Gas and Electric (34%), and Southwestern Electric Power Company (32%). Operation and maintenance expenses are reported in total in the transmission line schedule.

Schedule Page: 426.9 Line No.: 1 Column: a

These substations are jointly leased from the Arklahoma Corporation by Entergy Arkansas and other owners of this Corporation beginning December 9, 1947 and automatically renew annually. Common stock of the Arklahoma Corporation is jointly owned by Entergy Arkansas (34%), Oklahoma Gas and Electric (34%), and Southwestern Electric Power Company (32%). Operation and maintenance expenses are reported in total in the transmission line schedule.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	See footnote for schedule details.			
3	See footnote for allocation method details.			
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Schedule Page: 429 Line No.: 2 Column: a

Entergy service companies, including Entergy Operations, Inc. and Entergy Services, Inc., provide recurring, ongoing services to Entergy affiliates. Service company transactions are reported in the schedule below by type of category, where the amount charged or credited for each category is equal to or greater than the $250,000 threshold. All other Non-service company affiliate transactions reported in this schedule, if any, are reported by individual detailed transaction.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Corporate Support - General	Entergy Operations, Inc.	107000, 163000, 174200, 253107, 408110, 408122, 408123, 408142, 4265OT, 4265TX, 517000, 519000, 520000, 524000, 528000, 529000, 530000, 531000, 532000, 920000, 926000, 930200	4,294,840
3	Nuclear - Regulated	Entergy Operations, Inc.	107000, 163000, 174104, 174200, 253107, 408110, 4265OT, 4265TX, 517000, 519000, 520000, 524000, 528000, 529000, 530000, 531000, 532000, 920000, 921000, 926000	137,879,083
4	Nuclear Corporate Support	Entergy Operations, Inc.	107000, 163000, 174104, 253107, 408110, 4265OT, 4265TX, 517000, 524000, 528000, 531000, 532000, 920000, 925000, 926000	4,336,570
5	System Benefits	Entergy Operations, Inc.	107000, 163000, 174104, 174200, 253107, 4265OT, 524000, 926000	24,229,023
6	Administration	Entergy Services, Inc.	107000, 163000, 174101, 174104, 174200, 184001, 408110, 421000, 426400, 426500, 431000, 454000, 500000, 506000, 507000, 511000, 514000, 517000, 520000, 524000, 525000, 528000, 529000, 532000, 560000, 566000, 568000, 569000, 573000, 575201, 580000, 588000, 589000, 591000, 598000, 870000, 880000, 886000, 894000, 901000, 907000, 909000, 910000, 920000, 921000, 923000, 926000, 930200, 930210, 931000, 935000	3,670,237
7	Capital Project	Entergy Services,	107000, 174101, 253107,	1,079,866

	Excellence	Inc.	408110, 426500, 4265OT, 4265TX, 500000, 506000, 512000, 514000, 517000, 524000, 560000, 566000, 920000, 921000, 923000, 926000, 930200	
8	Chief Administrative Officer	Entergy Services, Inc.	408110, 426100, 426500, 920000, 921000, 923000, 926000, 930200	376,627
9	Corporate - Legal Services	Entergy Services, Inc.	107000, 174101, 174200, 181CPD, 228100, 253107, 408110, 426400, 4265OT, 4265TX, 506000, 524000, 560000, 566000, 920000, 921000, 923000, 926000, 928000, 930200, 931000, 935000	11,458,457
10	Corporate - Office of the Chief Executive Officer	Entergy Services, Inc.	184001, 408110, 426400, 426500, 920000, 921000, 923000, 925000, 926000, 930100, 930200, 931000, 935000	650,551
11	Corporate - Public Relations	Entergy Services, Inc.	107000, 174101, 174104, 184EST, 228100, 408110, 426100, 426400, 426500, 500000, 517000, 908000, 909000, 910000, 913000, 920000, 921000, 923000, 926000, 928000, 930100, 930200, 931000, 935000	3,741,711
12	Corporate Support - General	Entergy Services, Inc.	107000, 108220, 108230, 163000, 174101, 174104, 174200, 181CPD, 184001, 1840FS, 1840NC, 184EST, 186AM1, 228100, 228400, 253107, 4031AM, 408110, 408152, 4212AM, 426100, 426400, 426500, 4265OT, 4265TX, 430000, 500000, 506000, 510000, 512000, 513000, 514000, 517000, 519000, 520000, 524000, 528000, 528001, 530000, 531000, 532000, 535000, 541000, 546000, 549000, 551000, 553000, 556000, 557000, 560000, 561000, 561100, 561200, 561300, 561500, 561600, 562000, 566000, 568000, 569000, 569100, 570000, 575201, 580000, 581000, 583000, 584000, 586000, 587000, 588000, 590000, 592000, 593000, 595000, 596000, 596100, 597000, 598000, 901000, 902000, 903001, 903002, 905000, 907000,	19,912,881

FOOTNOTE DATA

			908000, 909000, 910000, 912000, 916000, 920000, 921000, 923000, 924000, 925000, 926000, 928000, 930100, 930200, 930201, 935000	
13	Customer Service Support	Entergy Services, Inc.	107000, 174101, 184001, 184EST, 253107, 408110, 4265OT, 4265TX, 560000, 580000, 586000, 587000, 588000, 901000, 902000, 903001, 903002, 905000, 907000, 910000, 913000, 916000, 920000, 921000, 926000, 928000, 931000, 935000	9,862,879
14	Distribution	Entergy Services, Inc.	107000, 174101, 184001, 184EST, 253107, 408110, 4265OT, 4265TX, 560000, 561200, 568000, 569000, 580000, 581000, 588000, 590000, 591000, 592000, 598000, 903002, 920000, 926000	396,169
15	Finance - Finance and Accounting	Entergy Services, Inc.	107000, 163000, 174101, 174200, 181CPD, 184001, 1840FS, 1840NC, 184EST, 228100, 253107, 408110, 408123, 408202, 426100, 426400, 426500, 4265OT, 4265TX, 500000, 506000, 560000, 568000, 580000, 598000, 901000, 903001, 903002, 905000, 908000, 920000, 921000, 923000, 924000, 925000, 926000, 928000, 930100, 930200, 930201, 931000, 935000	16,307,869
16	Finance - Information Technology	Entergy Services, Inc.	107000, 163000, 174101, 174104, 174200, 184001, 186AM1, 228100, 253107, 408110, 426100, 4265OT, 4265TX, 454000, 500000, 506000, 507000, 514000, 517000, 524000, 525000, 532000, 539000, 549000, 550000, 554000, 556000, 560000, 561200, 566000, 567000, 568000, 569100, 573000, 580000, 588000, 589000, 598000, 901000, 902000, 903001, 903002, 907000, 908000, 910000, 916000, 920000, 921000, 923000, 926000, 930200, 931000, 935000	20,556,395
17	Fossil Operations	Entergy Services, Inc.	107000, 152000, 163000, 174101, 1840FS, 253107,	10,019,027

FOOTNOTE DATA

			408110, 426400, 426500, 4265OT, 4265TX, 500000, 506000, 507000, 510000, 511000, 512000, 513000, 514000, 535000, 539000, 541000, 546000, 549000, 551000, 553000, 560000, 566000, 920000, 921000, 923000, 926000, 930200, 931000	
18	Human Resources	Entergy Services, Inc.	107000, 174101, 184001, 228100, 253107, 408110, 426100, 426500, 4265OT, 4265TX, 500000, 506000, 517000, 524000, 560000, 573000, 580000, 880000, 913000, 920000, 921000, 923000, 926000, 928000, 930200, 931000, 935000	7,451,252
19	Nuclear Corporate Support	Entergy Services, Inc.	107000, 163000, 174101, 174104, 1840NC, 253107, 408110, 408202, 426100, 426400, 4265OT, 4265TX, 517000, 519000, 520000, 524000, 525000, 528000, 529000, 530000, 531000, 532000, 903002, 920000, 921000, 926000, 930201	13,734,796
20	Nuclear Operations	Entergy Services, Inc.	107000, 174104, 253107, 408110, 4265OT, 4265TX, 517000, 524000, 528000, 920000, 921000, 926000, 930201	498,097
21	Operations and Performance	Entergy Services, Inc.	107000, 174101, 184001, 184EST, 253107, 408110, 426100, 426400, 426500, 4265OT, 4265TX, 500000, 506000, 560000, 566000, 580000, 920000, 921000, 923000, 926000, 930200, 931000	2,736,106
22	RTO Implementation	Entergy Services, Inc.	107000, 184001, 253107, 408110, 4265OT, 4265TX, 500000, 506000, 556000, 560000, 566000, 920000, 921000, 923000, 925000, 926000, 928000, 930200, 931000	6,062,375
23	Supply Chain	Entergy Services, Inc.	107000, 108220, 108230, 163000, 174101, 174200, 228100, 253107, 408110, 4265OT, 4265TX, 500000, 506000, 512000, 560000, 580000, 586000, 588000, 920000, 921000, 923000, 926000, 930100, 930200	3,739,402
24	System Benefits	Entergy Services, Inc.	107000, 108220, 108230, 163000, 174101, 174104,	23,644,075

FOOTNOTE DATA

			174200, 181CPD, 184001, 1840FS, 1840NC, 184EST, 186AM1, 228100, 253107, 426100, 426400, 4265OT, 431000, 568000, 910000, 921000, 923000, 925000, 926000, 931000	
25	System Planning	Entergy Services, Inc.	107000, 163000, 174101, 228100, 253107, 408110, 426100, 4265OT, 4265TX, 454000, 500000, 506000, 507000, 514000, 556000, 557000, 561200, 908000, 916000, 920000, 921000, 923000, 926000, 928000, 930200, 931000, 935000	5,938,077
26	Tax And Interest Expense	Entergy Services, Inc.	408122, 408123, 408142, 408152, 408165, 409112, 409114, 410101, 410120, 411110, 411120, 411430, 419000, 419011, 426310, 430000, 431000	2,289,295
27	Transmission	Entergy Services, Inc.	107000, 108230, 174101, 174200, 184001, 184EST, 228100, 253107, 408110, 426100, 4265OT, 4265TX, 500000, 560000, 561100, 561200, 561300, 561500, 561600, 562000, 566000, 567000, 568000, 569000, 569100, 570000, 571000, 573000, 575201, 580000, 582000, 588000, 589000, 590000, 592000, 593000, 903001, 920000, 921000, 923000, 926000, 928000, 930200	22,276,162
28	Utility Management and Support Services	Entergy Services, Inc.	107000, 174101, 174200, 184001, 253107, 408110, 426100, 426500, 4265OT, 4265TX, 517000, 560000, 580000, 588000, 903001, 909000, 912000, 913000, 916000, 920000, 921000, 923000, 926000, 928000, 930100, 930200, 931000, 935000	8,758,722
29	Utility Support - Distribution	Entergy Services, Inc.	107000, 174101, 184001, 1840FS, 1840NC, 184EST, 228400, 253107, 408110, 4265OT, 4265TX, 560000, 566000, 580000, 587000, 588000, 589000, 590000, 591000, 595000, 596000, 596100, 598000, 916000, 920000, 921000, 923000, 925000, 926000, 930200, 935000	3,897,892

30	Utility Support - Operations	Entergy Services, Inc.	107000, 174101, 184EST, 253107, 408110, 4265OT, 4265TX, 560000, 561500, 580000, 588000, 589000, 593000, 903001, 911000, 916000, 920000, 921000, 923000, 926000, 931000	753,721
31	Customer Service Support - Provide Call Center Contact.	Entergy Gulf States Louisiana, L.L.C.	408110, 903001, 926000	477,384
32	Storm Distribution Support - Repairs, Coordination and Management of Storm Restoration.	Entergy Gulf States Louisiana, L.L.C.	174101, 408110, 920000, 926000	721,200
33	Distribution Support - Return meters to stores inventory.	Entergy Louisiana, LLC	108230	(309,172)
34	Fossil Operations - Provide Operations Supervision.	Entergy Louisiana, LLC	408110, 546000, 926000	307,021
35	Fossil Support - Ouachita Plant Operations and Support.	Entergy Louisiana, LLC	163000, 408110, 546000, 548000, 549000, 551000, 553000, 920000, 926000	2,188,521
36	Inventory Transfers of Materials and Supplies.	Entergy Louisiana, LLC	154PAS	2,277,939
37	Storm Distribution Support - Repairs, Coordination and Management of Storm Restoration.	Entergy Louisiana, LLC	174101, 408110, 920000, 926000	1,665,655
38	System Benefits Support - Design and administration of benefit plans.	Entergy Louisiana, LLC	163000, 926000	344,924
39	Inventory Transfers of Materials and Supplies.	Entergy Mississippi, Inc.	154PAS	375,888
40	Storm Distribution Support - Repairs, Coordination and Management of Storm Restoration.	Entergy Mississippi, Inc.	174101, 408110, 920000, 926000	562,466
41	Storm Distribution Support - Repairs, Coordination and Management of Storm Restoration.	Entergy New Orleans, Inc.	174101, 408110, 920000, 926000	253,799
42	Customer Service Support - Provide	Entergy Texas, Inc.	408110, 903001, 926000	329,652

FOOTNOTE DATA

	Call Center Contact.			
43	Storm Distribution Support - Repairs, Coordination and Management of Storm Restoration.	Entergy Texas, Inc.	174101, 408110, 920000, 926000	428,638
44	**Non-power Goods or Services Provided for Affiliate**			
45	Customer Service Support - Provide Call Center Contact.	Entergy Gulf States Louisiana, L.L.C.	408110, 903001, 926000	662,987
46	Customer Service Support - Provide Call Center Contact.	Entergy Louisiana, LLC	408110, 903001, 926000	985,136
47	Distribution Support - Installation of distribution circuit, transformer, and related facilities and equipment.	Entergy Louisiana, LLC	107000	518,503
48	Distribution Support - Installation of meters, wires, and lighting. Including maintenance and safety.	Entergy Louisiana, LLC	107000, 580000	2,010,645
49	Distribution Support - Truck stock lighting and materials installation.	Entergy Louisiana, LLC	107000, 580000	1,124,961
50	Inventory Transfers of Materials and Supplies.	Entergy Louisiana, LLC	154PAS, 163000	4,130,001
51	Supply Chain Support - Materials testing and compliance.	Entergy Louisiana, LLC	408110, 586000, 588000, 926000	317,303
52	Customer Service Support - Provide Billing and Account Maintenance.	Entergy Mississippi, Inc.	408110, 903002, 926000	445,507
53	Customer Service Support - Provide Call Center Contact.	Entergy Mississippi, Inc.	408110, 903001, 926000	691,826
54	Distribution Support - Installation of	Entergy Mississippi, Inc.	107000, 580000	530,884

FOOTNOTE DATA

	meters, wires, and lighting. Including maintenance and safety.			
55	Distribution Support - Truck stock lighting and materials installation.	Entergy Mississippi, Inc.	107000, 580000	330,390
56	Inventory Transfers of Materials and Supplies.	Entergy Mississippi, Inc.	154PAS	1,310,230
57	Customer Service Support - Provide Call Center Contact.	Entergy New Orleans, Inc.	408110, 903001, 926000	284,704
58	Customer Service Support - Provide Call Center Contact.	Entergy Texas, Inc.	408110, 903001, 926000	445,071
59	Inventory Transfers of Materials and Supplies.	Entergy Texas, Inc.	154PAS	667,452

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Listed below are the allocation factors used to allocate costs to the affiliate.
Note: Where no allocation factor is provided for the non-power goods or services listed on Schedule 429, the costs associated with those goods and services were directly charged and not allocated.

Description of the Non-Power Good or Service	Cost Allocator(s)
Entergy Operations, Inc.	
Corporate Support - General	EMPLOEOI, SPLEOIPL, SPLEUNIT
Nuclear - Regulated	EMPLOEOI, SPLEOIPL, SPLEUNIT
Nuclear Corporate Support	EMPLOEOI, SPLEOIPL, SPLEUNIT
System Benefits	EMPLOEOI, SPLEOIPL, SPLEUNIT
Entergy Services, Inc.	
Administration	APPSUPAL, ASSTSALL, CAPAOPCO, CUSEOPCO, CUSTCALL, CUSTEGOP, EMPLOFOS, EMPLOREG, EMPLOYAL, GENLDREG, GENLEDAL, LBRBILAL, LBRCORPT, LBREXAFF, LBRLEGAL, LVLSVCAL, MACCTALL, PKLOADAL, RECDMGNT, SNUCSITE, SQFTALLC, TELPHALL, TELXGENS, TRASUBOP, TRSBLNOP
Capital Project Excellence	APPSUPAL, ASSTSALL, CAPAOPCO, CUSEGXTX, EMPLOYAL, LBRBILAL, PKLOADAL, SNUCUNIT
Chief Administrative Officer	ASSTSALL, EMPLOYAL, ITSPENDA, LBRCRPUT, PKLOADAL, SCPSPALL
Corporate - Legal Services	APPSUPAL, ASSTSALL, CAPAOPCO, COALARGS, CUSEOPCO, CUSTEGOP, EMPLOFOS, EMPLOREG, EMPLOYAL, EMPLTRAN, EMPLUTOP, GENLEDAL, ITSPENDA, LBRBILAL, LBRCORPT, LBRLEGAL, LBRSUPCN, LBRUTOPN, LOADSYAG, LVLSVCAL, OWNISFI, PKLOADAL, RECDMGNT, SNUCUNIT,

FOOTNOTE DATA

	SQFTALLC, TELXGENS, TRSBLNOP
Corporate - Office of the Chief Executive Officer	ASSTSALL, CUSEOPCO, LBRCORPT, LVLSVCAL, SNUCSITE
Corporate - Public Relations	ASSTSALL, CAPAOPCO, CUSEOPCO, CUSTCALL, CUSTEGOP, EMPLOREG, EMPLOYAL, LBRBILAL, LBRCORPT, LBREXAFF, LBRLEGAL, LBRSUPCN, LBRUTOPN, LOADSYAG, LVLSVCAL, MACCTALL, PKLOADAL, SNUCSITE, SQFTALLC, TELXGENS, TRSBLNOP
Corporate Support - General	APPSMVSX, APPSUNIX, APPSUPAL, APPSWINT, APTRNALL, ARTRNALL, ASSTSALL, ASSTSREG, BNKACCTA, CAPANWES, CAPAOPCO, CAPXCOPC, CEAOUTAL, COALARGS, COMCLAIM, CUSEGALL, CUSEGRXT, CUSEGXTX, CUSEOPCO, CUSTCALL, CUSTEGOP, CUSTEXTX, EMPLFRAN, EMPLOCSS, EMPLOFOS, EMPLOREG, EMPLOYAL, EMPLPRES, EMPLTRAN, EMPLUTOP, FIBRMREG, GENLDREG, GENLEDAL, INSPREAL, ITSPENDA, LBRBILAL, LBRBLFOS, LBRBLNUC, LBRCRPUT, LBREXAFF, LBRFINAN, LBRINFOR, LBRLEGAL, LBRSUPCN, LBRUTOPN, LOADOPCO, LOADSYAG, LVLSVCAL, MACCTALL, MACCTNLA, MACCTXTX, OWNISFI, PCNUMALL, PCNUMXNR, PKLOADAL, PLLOSSAL, PRCHKALL, PWRSNUCA, RADIOALL, RECDMGNT, SCDSPALL, SCFSPALL, SCLDTMLS, SCMATRAN, SCMATXNU, SCPSPALL, SCPSPXNC, SCTDSPAL, SCTSPALL, SECT263A, SNUCSITE, SNUCUNIT, SQFTALLC, TELPHALL, TRALINOP, TRANSPND, TRASUBOP, TRSBLNOP, VEHCLFOS, VEHCLNUC, VEHCLUSG
Customer Service Support	CUSTCALL, CUSEGXTX, CUSEOPCO, CUSTCALL, CUSTEGOP, CUSTEXTX, EMPLOCSS, EMPLOYAL, EMPLUTOP, LBRCORPT, LBRFINAN, LBRLEGAL, LBRUTOPN, MACCTALL, PKLOADAL, SQFTALLC, TELPHALL, TELXGENS, TRSBLNOP
Distribution	CUSEOPCO, CUSTEGOP, EMPLFRAN, EMPLOYAL, EMPLUTOP, LBRCORPT, PKLOADAL, SQFTALLC, TELPHALL, TELXGENS, TRASUBOP, TRSBLNOP
Finance - Finance and Accounting	APPSUPAL, APTRNALL, ARTRNALL, ASSTSALL, ASSTSREG, BNKACCTA, CAPAOPCO, CAPXCOPC, CEAOUTAL, COALARGS, CUSEGALL, CUSEGXTX, CUSEOPCO, CUSTCALL, CUSTEGOP, EMPLOREG, EMPLOYAL, EMPLPRES, GENLDREG, GENLEDAL, INSPREAL, ITSPENDA, LBRBILAL, LBRCORPT, LBREXAFF, LBRFINAN, LBRINFOR, LBRLEGAL, LBRSUPCN, LBRUTOPN, LOADOPCO, LOADSYAG, LVLSVCAL, OWNISFI, PKLOADAL, PLLOSSAL, PRCHKALL, RADIOALL, SCMATRAN, SCMATXNU, SCPSPALL, SECT263A, SNUCSITE, SNUCUNIT, SQFTALLC, TELPHALL, TELXGENS, TRALINOP, TRANSPND, TRSBLNOP, VEHCLFOS, VEHCLNUC, VEHCLUSG
Finance - Information Technology	APPSMVSX, APPSUNIX, APPSUPAL, APPSWINT, APTRNALL, ASSTSALL, CAPACALL, CAPAOPCO, CEAOUTAL, CUSEGRXT, CUSEGXTX, CUSEOPCO, CUSTCALL, CUSTEALL, CUSTEGOP, CUSTEXTX, EMPLOYAL, FIBRMREG, GENLEDAL, ITSPENDA, LBRBILAL, LBRCORPT, LBRFINAN, LBRSUPCN, LOADOPCO, LVLSVCAL, MACCTALL, PCNUMALL, PCNUMXNR, PKLOADAL, PRCHKALL, RADIOALL, RECDMGNT, SCDSPALL, SCLDTMLS, SCMATRAN, SCMATXNU, SCPSPALL, SCPSPXNC, SCTDSPAL, SNUCSITE, SQFTALLC, TELPHALL, TELXGENS, TRANSPND, TRSBLNOP, VEHCLFOS, VEHCLUSG
Fossil Operations	APPSUPAL, ASSTSALL, CAPANWES, CAPAOPCO, CUSEOPCO, EMPLOFOS, EMPLOYAL, LBRBILAL, LBRCORPT, LBRFINAN, PKLOADAL, SCDSPALL, SQFTALLC, TELPHALL, TRSBLNOP, VEHCLFOS
Human Resources	ASSTSALL, CAPAOPCO, CUSTCALL, CUSTEGOP, EMPLFRAN, EMPLOCSS, EMPLOFOS, EMPLOREG, EMPLOYAL, EMPLPRES, EMPLTRAN, EMPXENUC, LBRBILAL, LBRCORPT, LVLSVCAL, PKLOADAL, PRCHKALL, SNUCSITE, SQFTALLC, TRSBLNOP, VEHCLUSG
Nuclear Corporate Support	APTRNALL, ASSTSALL, EMPLOYAL, ITSPENDA, LBRCORPT, LBRSUPCN, LVLSVCAL, PWRSNUCA, SCFSPALL, SCMATRAN, SCPSPALL, SNUCSITE, SNUCUNIT, TRSBLNOP, VEHCLNUC
Nuclear Operations	EMPLOYAL, LBRCORPT, SNUCSITE, SNUCUNIT
Operations and Performance	ASSTSALL, CAPAOPCO, CUSEOPCO, CUSTEGOP, EMPLFRAN, EMPLOFOS, EMPLOYAL, EMPLTRAN, LBRBILAL, LBRCORPT, LBREXAFF, LVLSVCAL,

FOOTNOTE DATA

	PKLOADAL, SCPSPALL, SNUCSITE, TRANSPND, TRSBLNOP
RTO Implementation	ASSTSALL, CAPXCOPC, CEAOUTAL, CUSEOPCO, CUSTEGOP, EMPLOYAL, LBREXAFF, LOADSYAG, PKLOADAL, TRSBLNOP
Supply Chain	APTRNALL, ASSTSALL, CAPAOPCO, CUSEGXTX, CUSEOPCO, CUSTEGOP, EMPLOYAL, ITSPENDA, LBRCORPT, LBRSUPCN, LVLSVCAL, SCDSPALL, SCFSPALL, SCLDTMLS, SCMATXNU, SCPSPALL, SCPSPXNC, SCTSPALL, SQFTALLC, TELXGENS, TRSBLNOP, VEHCLUSG
System Benefits	APPSMVSX, APPSUNIX, APPSUPAL, APPSWINT, APTRNALL, ARTRNALL, ASSTSALL, ASSTSREG, BNKACCTA, CAPANWES, CAPAOPCO, CAPXCOPC, CEAOUTAL, COALARGS, COMCLAIM, CUSEGALL, CUSEGRXT, CUSEGXTX, CUSEOPCO, CUSTCALL, CUSTEGOP, CUSTEXTX, EMPLFRAN, EMPLOCSS, EMPLOFOS, EMPLOREG, EMPLOYAL, EMPLPRES, EMPLTRAN, EMPLUTOP, EMPOPCPE, FIBRMREG, GENLDREG, GENLEDAL, INSPREAL, ITSPENDA, LBRBILAL, LBREXAFF, LBRFINAN, LBRINFOR, LBRLEGAL, LBRSUPCN, LBRUTOPN, LOADOPCO, LOADSYAG, LVLSVCAL, MACCTALL, MACCTNLA, MACCTXTX, OWNISFI, PCNUMALL, PCNUMXNR, PKLOADAL, PLLOSSAL, PRCHKALL, PWRSNUCA, RADIOALL, RECDMGNT, SCDSPALL, SCFSPALL, SCLDTMLS, SCMATRAN, SCMATXNU, SCPSPALL, SCPSPXNC, SCTDSPAL, SCTSPALL, SECT263A, SNUCSITE, SNUCUNIT, SQFTALLC, TELPHALL, TRALINOP, TRANSPND, TRASUBOP, TRSBLNOP, VEHCLFOS, VEHCLNUC, VEHCLUSG
System Planning	ASSTSALL, CAPAOPCO, CAPXCOPC, COALARGS, CUSTEGOP, EMPLOYAL, LBRBILAL, LBRLEGAL, LOADOPCO, LOADSYAG, MACCTALL, OWNISFI, PKLOADAL, SQFTALLC, TRSBLNOP
Tax And Interest Expense	EMPLPRES, LBRBILAL, LVLSVCAL, PKLOADAL, TRSBLNOP
Transmission	ASSTSALL, CAPAOPCO, CUSEOPCO, CUSTEGOP, CUSTOEAM, EMPLOYAL, EMPLTRAN, EMPLUTOP, ITSPENDA, LBRBILAL, LBRCORPT, LOADOPCO, LOADSYAG, PCNUMXNR, PKLOADAL, SQFTALLC, TELXGENS, TRALINOP, TRANSPND, TRASUBOP, TRSBLNOP
Utility Management and Support Services	ASSTSALL, CUSEGXTX, CUSEOPCO, CUSTEGOP, EMPLFRAN, EMPLOREG, EMPLOYAL, EMPLPRES, EMPLUTOP, GENLEDAL, LBRCORPT, LBREXAFF, LBRLEGAL, LBRUTOPN, LOADSYAG, LVLSVCAL, MACCTALL, MACCTNLA, MACCTXTX, PKLOADAL, SQFTALLC, TELPHALL, TELXGENS, TRANSPND, TRSBLNOP
Utility Support - Distribution	COMCLAIM, CUSEOPCO, CUSTEGOP, EMPLFRAN, EMPLOYAL, EMPLUTOP, GENLEDAL, LBRCORPT, LBRFINAN, LVLSVCAL, MACCTALL, PKLOADAL, SQFTALLC, TELXGENS, TRALINOP, TRANSPND, TRSBLNOP, VEHCLFOS, VEHCLNUC, VEHCLUSG
Utility Support - Operations	ASSTSALL, CUSEOPCO, CUSTCALL, EMPLFRAN, EMPLOYAL, EMPLUTOP, MACCTALL, RADIOALL, TRALINOP, TRANSPND, TRASUBOP, TRSBLNOP

Cost Allocator Descriptions

Cost Allocator	Cost Allocator Title	Cost Allocator Description
Entergy Operations, Inc.		
EMPLOEOI	Nuclear South Site Employees	Based on Nuclear South site employees
SPLEOIPL	Nuclear South Plant Sites	Based on the number of Nuclear South Plant Sites
SPLEUNIT	Nuclear South Units	Based on the number of Nuclear South Units
Entergy Services, Inc.		
APPSMVSX	Server & Mainframe Usage (MVS)	Based on mainframe usage

APPSUNIX	Server & Mainframe Usage (UNX)	Based on UNIX server usage
APPSUPAL	Server & Mainframe Usage - Composite	Based on a weighted composite of UNIX and NT servers and mainframe usage
APPSWINT	Server & Mainframe Usage (NTS)	Based on WINTEL server usage
APTRNALL	Accounts Payable Transactions	Based on a twelve month number of accounts payable transactions processed
ARTRNALL	Accounts Receivable Invoices	Based on a twelve month number of accounts receivable transactions processed
ASSTSALL	Total Assets	Based on total assets at period end
ASSTSREG	Total Assets - Regulated BU's	Based on total assets at period end for all Regulated business units
BNKACCTA	Bank Accounts	Based on number of bank accounts at period end
CAPACALL	System Capacity - Reg and Non-Reg	Based on the power level, in kilowatts, that could be achieved if all non-nuclear generating units (including Harrison County, RISEC and all Reg companies) were operating at maximum capability simultaneously
CAPANWES	System Capacity - NorthWest	Based on the power level, in kilowatts, that could be achieved if all non-nuclear NorthWestern Region (EAI & ETI) generating units were operating at maximum capacity simultaneously
CAPAOPCO	System Capacity	Based on the power level, in kilowatts, that could be achieved if all non-nuclear generating units were operating at maximum capability simultaneously
CAPXCOPC	System Capacity without Coal and Nuclear	Based on the power level, in kilowatts, that could be achieved if all non-coal and non-nuclear generating units were operating at maximum capability simultaneously
CEAOUTAL	Open CEA's	Based on average outstanding CEA's (Capital Expenditure Authorizations)
COALARGS	Coal Consumption	Based on the quantity of tons of coal delivered to each coal plant within the Entergy System
COMCLAIM	Workers' Compensation Claims	Based on number of Open Workers' Compensation claims
CUSEGALL	Electric & Gas Customers - Retail Customers	Based on a twelve month average number of electric and gas residential, commercial, industrial, government, and municipal customers for Legal Entities EAI, EGSL, ELL, EMI, ENOI, and ETI
CUSEGRXT	Electric & Gas	Based on a 12 month average number

	Retail Customers - excluding Texas	of electric and gas retail customers, excluding Texas (ETI)
CUSEGXTX	Electric & Gas Customers - excluding Texas	Based on a twelve month average number of electric and gas residential, commercial, industrial, government, and municipal general business customers excluding Texas (ETI)
CUSEOPCO	Electric Customers	Based on a twelve month average number of electric residential, commercial, industrial, government, and municipal customers
CUSTCALL	Customer Call Centers	Based on a twenty-four month average of customer calls
CUSTEALL	Electric Customers - Retail Customers	Based on a twelve month average number of electric residential, commercial, industrial, government, and municipal customers for Legal Entities EAI, EGS-LA, ELL, EMI, ENOI, and ETI
CUSTEGOP	Electric and Gas Customers	Based on a twelve month average number of electric and gas residential, commercial, industrial, government, and municipal general business customers
CUSTEXTX	Electric Customers - excluding Texas	Based on a twelve month average number of electric residential, commercial, industrial, government, and municipal customers for Legal Entities EAI, EGSL, ELL, EMI, and ENOI
CUSTOEAM	Electric Customers - EAI and EMI	Based on a twelve month average number of electric residential, commercial, industrial, government, and municipal customers for EAI and EMI
EMPLFRAN	Employees - Franchise Operations	Based on the number of full and part time employees within Franchise Operations
EMPLOCSS	Employees - Customer Support Services	Based on the number of full and part time employees within Customer Support Service
EMPLOFOS	Employees - Fossil Plant Operations	Based on the number of full and part time employees within Fossil Plant Operations
EMPLOREG	Full and Part Time Employees of EAI, EGSL, ELL, EMI, ETI, ESI, EOI, & ENOI	Based on the number of full and part time employees at period end for EAI, EGSL, ELL, EMI, ENOI, EOI, ETI, and ESI
EMPLOYAL	Full and Part Time Employees	Based on the number of full and part time employees at period end
EMPLPRES	Employees - State President	Based on the number of full and part time employees within State President Organizations
EMPLTRAN	Employees -	Based on the number of full and

	Transmission	part time employees within Transmission
EMPLUTOP	Employees - Utility Operations	Based on the number of full and part time employees within Utility Operations
EMPOPCPE	Full and Part Time Employees of EAI, EGSL, ELL, EMI, ENOI, ETI, and EOI	Based on the number of full and part time employees at period end for EAI, ETI, ELL, EMI, ENOI, EGSL, and EOI
EMPXENUC	Employees - Excluding ENUC	Based on the number of full and part time employees at period end, excluding ENUC
FIBRMREG	Fiber Miles	Based on capacity and usage of the Entergy System's fiber optic network
GENLDREG	General Ledger Transactions - Regulated Companies	Based on general ledger transactions for regulated companies
GENLEDAL	General Ledger Transactions	Based on general ledger transactions
INSPREAL	Insurance Premiums	Based on non-nuclear insurance premiums
ITSPENDA	Information Technology Total Spending	Based on Information Technology 12 month total spending
LBRBILAL	ESI Labor Costs Billed	Based on total labor dollars billed to each company by ESI
LBRBLFOS	ESI Labor Billed - Fossil	Based on total labor dollars billed to each company by ESI for the Fossil function
LBRBLNUC	ESI Labor Billed - Nuclear	Based on total labor dollars billed to each company by ESI for the Nuclear function
LBRCORPT	ESI Labor Billed - Corporate	Based on total labor dollars billed to each company by ESI for the Corporate function
LBRCRPUT	ESI Labor Billed - Corporate & Utility Ops	Based on total labor dollars billed to each company by ESI for the Corporate & Utility Ops functions
LBREXAFF	ESI Labor Billed - External Affairs	Based on total labor dollars billed to each company by ESI for the External Affairs function
LBRFINAN	ESI Labor Billed - Finance	Based on total labor dollars billed to each company by ESI for the Finance function
LBRINFOR	ESI Labor Billed - IT	Based on total labor dollars billed to each company by ESI for the IT function
LBRLEGAL	ESI Labor Billed - Legal	Based on total labor dollars billed to each company by ESI for the Legal function
LBRSUPCN	ESI Labor Billed -Supply Chain	Based on total labor dollars billed to each company by ESI for the Supply Chain function
LBRUTOPN	ESI Labor Billed-Utility Operations	Based on total labor dollars billed to each company by ESI for the

		Utility Operations function
LOADOPCO	Responsibility Ratio	Based on the ratio company's load at time of system peak load. The load is the average twelve monthly highest clock hour demands in kilowatts of the company's interconnected system, occurring each month coincident with the system peak load.
LOADSYAG	Responsibility Ratio for System Agreement companies only	Based on the ratio company's load at time of system peak load. The load is the average twelve monthly highest clock hour demands in kilowatts of the company's interconnected system, occurring each month coincident with the system peak load. Excluding companies that are not a part of the system agreement.
LVLSVCAL	ESI Service Level	Based on ESI total billings to each System company
MACCTALL	Managed Accounts	Based on number of retail managed accounts
MACCTNLA	Managed Accounts - EAI, EMI, and ETI	Based on number of retail managed accounts, excluding the accounts of all Louisiana companies
MACCTXTX	Managed Accounts - EAI, EGSLA, ELL, EMI and ENOI	Based on number of retail managed accounts, excluding the accounts of ETI
OWNISFI	Percentage Ownership - SFI	Based on the percentage ownership of SFI
PCNUMALL	Number of PC's	Based on the number of PC's within each business unit
PCNUMXNR	Number of PC's - Excluding Non-Regs	Based on the number of PC's at EAI, EGSL, ELL, EMI, ENOI, EOI, ESI, and ETI
PKLOADAL	Peak Load Ratio	Based on the ratio of each Client Company’s load to the peak load at time of all companies peak load. The calculation of Peak Load Ratio is performed using a twelve month rolling average of the coincident peaks.
PLLOSSAL	Property & Liability Paid Losses	Based on a five-year annual average of the property & liability losses paid by the system companies
PRCHKALL	Payroll Checks Issued	Based on the number of payroll checks issued for each legal entity
PWRSNUCA	Pressure Water Reactors	Based on the number of Pressure Water Reactors Plant units
RADIOALL	Radio Usage	Based on usage of Entergy's 2-way radio system
RECDMGNT	Records Management	Based on the number of full and part time employees at period end, excluding the Nuclear function using records management services
SCDSPALL	Supply Chain	Based on Supply Chain Procurement

	Spending - Distribution	Total Spending for the Distribution Function
SCFSPALL	Supply Chain Spending - Fossil	Based on Supply Chain Procurement Total Spending for the Fossil Function
SCLDTMLS	Supply Chain - Labor Dollars	Supply Chain Labor Dollars for the Transformer, Meter, and Light Shops
SCMATRAN	Supply Chain Transactions in Passport	Based on the number of Supply Chain materials transactions for each business unit in Passport
SCMATXNU	Supply Chain Transactions in Passport excluding Nuclear	Based on the number of Supply Chain materials transactions for each business unit in Passport excluding the Nuclear function
SCPSPALL	Supply Chain Total Spending	Based on Supply Chain's Procurement Total Spending
SCPSPXNC	Supply Chain Spending - Excluding Nuclear	Based on Supply Chain Procurement Total Spending; Excluding Nuclear for 12 months
SCTDSPAL	Supply Chain Spending - Distribution & Transmission	Based on Supply Chain's Procurement Total Spending for Distribution & Transmission functions
SCTSPALL	Supply Chain Spending - Transmission	Based on Supply Chain's Procurement Total Spending for Transmission
SECT263A	Section 263A Tax Services	Based on the expected tax savings from section 263
SNUCSITE	Nuclear Plant Sites	Based on the number of Nuclear Plant Sites
SNUCUNIT	Nuclear Units	Based on the number of Nuclear Units
SQFTALLC	Square Footage - All Companies	Based on square footage within all business units
TELPHALL	Number of Telephones	Based on the number of telephones within each business unit
TELXGENS	Number of Telephones - Excluding Remote	Based on the number of telephones excluding Remote Sites
TRALINOP	Transmission Line Miles	Based on the number of miles of transmission lines, weighted for design voltage (Voltage < 400kv = 1; Voltage >400kv =2)
TRANSPND	Transmission Budgeted Capital Expenditures	Based on Transmission Budgeted Capital Expenditures
TRASUBOP	Transmission Substations	Based on the number of high voltage substations weighted for Voltage (Voltage < 500kv = 1; Voltage >= 500kv = 2)
TRSBLNOP	Transmission Line Miles/Substation	Based on two components: Transmission Line Miles (30% weighting) and the Number of High Voltage Substations (70% weighting)
VEHCLFOS	Number of Vehicles	Based on the number of vehicles

	- Fossil	owned or leased by each business unit for the Fossil function only
VEHCLNUC	Number of Vehicles - Nuclear	Based on the number of vehicles owned or leased by each business unit for the Nuclear function only
VEHCLUSG	Number of Vehicles excluding Fossil & Nuclear	Based on the number of vehicles owned or leased by each business unit that participates in the usage based transportation allocation

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