

THIS FILING IS

Item 1: An Initial (Original) Submission OR Resubmission No. _____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2016)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2016)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)



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)

Entergy Arkansas, Inc.

Year/Period of Report

End of 2015/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.)

<u>Reference Schedules</u>	<u>Pages</u>
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 filed..."

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).

REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Entergy Arkansas, Inc.		02 Year/Period of Report End of 2015/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 Gina G. Bellott		06 Title of Contact Person 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 (504) 576-6753	09 This Report Is (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		10 Date of Report (Mo, Da, Yr) / /

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 Alyson M. Mount	03 Signature Alyson M. Mount	04 Date Signed (Mo, Da, Yr) 04/18/2016
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.

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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	NA
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	NA
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	NA
25	Unrecovered Plant and Regulatory Study Costs	230	NA
26	Transmission Service and Generation Interconnection Study Costs	231	NA
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

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
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/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	NA
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
- No annual report to stockholders is prepared

Name of Respondent Entergy Arkansas, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of <u>2015/Q4</u>
--	---	---------------------------------------	--

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) No

Name of Respondent Entergy Arkansas, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of <u>2015/Q4</u>
--	---	---------------------------------------	--

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent 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 beneficiaries for whom trust was maintained, and purpose of the trust.

As of December 31, 2015, Entergy Corporation owned 46,980,196 shares of the Respondent's common stock which represented 100% of the voting rights.

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	Arkansas Power & Light Company, LLC		90%	
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.			
20				
21				
22				
23				
24				
25				
26				
27				

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	Hugh T. McDonald	371,602
3			
4	Chief Executive Officer and Chairman of the Board		
5	of Entergy Corporation	Leo P. Denault	
6			
7	Executive VP and Chief Financial Officer	Andrew S. Marsh	
8			
9	Sr. VP and Chief Accounting Officer	Alyson M. Mount	
10			
11	Executive VP & Chief Operating Officer		
12	of Entergy Corporation (1)	Mark T. Savoff	
13			
14	Sr. VP & Chief Operating Officer		
15	of Entergy Corporation (2)	Paul D. Hinnenkamp	
16			
17	Exec. VP and General Counsel	Marcus V. Brown	
18			
19	Group President Utility Operations	Theodore H. Bunting, Jr.	
20			
21	Exec VP & Chief Nuclear Officer of Entergy Arkansas (1)	Jeffrey S. Forbes	
22			
23	Sr. VP & Chief Nuclear Officer of Entergy Arkansas (2)	Timothy G. Mitchell	
24			
25	Sr. VP - Human Resources and Chief Diversity		
26	Officer of Entergy Corporation	Donald W. Vinci	
27			
28	Executive VP & Chief Administrative Officer		
29	of Entergy Corporation	Roderick K. West	
30			
31	Sr. VP and General Tax Counsel	Joseph T. Henderson	
32			
33			
34			
35	(1) ceased effective November 2015		
36	(2) effective November 2015		
37			
38			
39			
40	* Officers whose salaries are not		
41	presented were compensated by		
42	other System companies and not		
43	by Entergy Arkansas.		
44			

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/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	425 W. Capitol Avenue, Little Rock, AR 72201
3		
4	Theodore H. Bunting, Jr. - Group President	
5	Utility Operations	639 Loyola Avenue, New Orleans, LA 70113
6		
7	Andrew S. Marsh - Executive VP & Chief Financial Officer	639 Loyola Avenue, New Orleans, LA 70113
8		
9	Mark T. Savoff - Executive VP & Chief Operating Officer	
10	of Entergy Corporation (1)	639 Loyola Avenue, New Orleans, LA 70113
11		
12	Paul D. Hinnenkamp - Senior VP & Chief Operating Officer	
13	of Entergy Corporation (2)	639 Loyola Avenue, New Orleans, LA 70113
14		
15		
16	(1) ceased effective November 2015	
17	(2) effective November 2015	
18		
19		
20		
21		
22		
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		
48		

Name of Respondent Entergy Arkansas, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of <u>2015/Q4</u>
--	---	---------------------------------------	--

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

Does the respondent have formula rates?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> 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	Arkansas Electric Cooperative Corporation (AECC)	
2	Wholesale Distribution Agreement RS No. 82	
3	Baseline Tariff	Docket No. ER14-133
4	Midcontinent ISO FERC Electric Tariff	
5	Fifth Revised Volume No. 1 (Baseline Att O)	Docket No. ER13-948
6		
7	Rate Schedule 705: Unit Power Sales/Designated	
8	Power Purchase Tariff (UPS/DPPT or MSS-4 Like)	
9	Baseline Tariff Filing	Docket No. ER13-1508
10	ANO 2 Decommissioning Costs	Docket No. ER16-644
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		
41		

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/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)?

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	20140611-5059	06/11/2014	ER14-133	2014 AECC Wholesale	RS No. 82
2				Formula Rate Update	
3					
4					
5					
6					
7					
8					
9					
10					
11	201512295162	12/29/2015	ER16-644	2015 ANO 2 Decommissioning Costs	RS No. 705
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					
42					
43					
44					
45					
46					

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

Schedule Page: 1061 Line No.: 1 Column: d

Filed biannually. There was no filing in 2015. The next filing will be in 2016.

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		(c) 70
3	118	Statement of Retained Earnings		(d) 29
4	118	Statement of Retained Earnings		(c) 36
5	204, 206	Electric Plant in Service		(b) 8-14, 18-24, 27-34, 37-43
6				and 50
7	204, 206	Electric Plant in Service		(b) 4, 86-95
8	206	Electric Plant in Service		(b) 97
9	219	Accumulated Provision for Depreciation		(b) 1
10	227	Materials and Supplies		(c) 1, 2
11	227	Materials and Supplies		(c) 12, 16
12	234	Accumulated Deferred Income Taxes (Account 190)		(c) 2
13	262	Taxes, Accrued, Prepaid and Charged During Year		(d) 18
14	262	Taxes, Accrued, Prepaid and Charged During Year		(d) 17
15	262	Taxes, Accrued, Prepaid and Charged During Year		(d) 2, 9
16	262	Taxes, Accrued, Prepaid and Charged During Year		(d) 3, 4, 10
17	266	Accumulated Deferred Investment Tax Credits		(f) 8
18	275	Accumulated Deferred Income Taxes (Account 282)		(k) 2
19	277	Accumulated Deferred Income Taxes (Account 283)		(k) 3
20	320-321	Electric Operation and Maintenance Expense		(c) 4, 6-11, 15-19, 24, 26-32
21				35-39, 44-49, 53-57, 62
22				64-66, 69-72
23	321	Electric Operation and Maintenance Expense		(c) 93, 107
24	323	Electric Operation and Maintenance Expense		(c) 181-184, 186-193
25	323	Electric Operation and Maintenance Expense		(c) 185
26	336	Depreciation Expense		(f) 2-7
27	336	Depreciation Expense		(f) 10
28	110-111	Comparative Balance Sheet		(c) 28, 52, 54
29	110-111	Comparative Balance Sheet		(c) 57
30	114	Statement of Income		(c) 14
31	206-207	Electric Plant in Service		(g) 58
32	206-207	Electric Plant in Service		(g) 75
33	2006-207	Electric Plant in Service		(g) 75
34	206-207	Electric Plant in Service		(g) 75
35	219	Accumulated Provision for Depreciation (Acc 108)		(b) 26
36	219	Accumulated Provision for Depreciation (Acc 108)		(b) 26
37	219	Accumulated Provision for Depreciation (Acc 108)		(b) 28
38	262-263	Taxes Accrued, Prepaid and Charged During Year		(d) 7
39	262-263	Taxes Accrued, Prepaid and Charged During Year		(d), (l) 14, 18
40	274-277	Accumulated Deferred Income Taxes		(k) 9
41	274-277	Accumulated Deferred Income Taxes		(k) 9
42	300	Electric Operating Revenues		(b) 19
43	300	Electric Operating Revenues		(b) 19
44	322	Electric Operation and Maintenance Expenses		(b) 156

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	323	Electric Operation and Maintenance Expenses		(b) 197
2	336	Depreciation and Amortization of Electric Plant		(f) 8
3	336	Depreciation and Amortization of Electric Plant		(f) 8
4	336	Depreciation and Amortization of Electric Plant		(f) 10
5	354	Distribution of Salaries and Wages		(b) 20
6	354	Distribution of Salaries and Wages		(b) 21
7	354	Distribution of Salaries and Wages		(b) 23
8	354	Distribution of Salaries and Wages		(b) 24-25
9	355	Distribution of Salaries and Wages		(b) 96
10				
11		Footnotes explaining differences are attached.		
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				
42				
43				
44				

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

Schedule Page: 1062.1 Line No.: 11 Column: b

Line No.	Page No(s).	Schedule	Column	Line No.
1	111	Comparative Balance Sheet Prepayments used in RS No.705, Unit Power Sales/Designated Power Purchase Tariff (UPS/DPPT), 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 UPS/DPPT, 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
3	118	Statement of Retained Earnings Return on Preferred Stock used in UPS/DPPT and in the annual AECC Wholesale Distribution Formula Rate (WDSA), differs from Form 1 amounts because the formula rates calculate Return on Preferred Stock using the embedded cost of Preferred Stock at the last day of the previous month/year times the Preferred Stock Capitalization ratio at the last day of the previous month	(d)	29
4	118	Statement of Retained Earnings Return on Common Equity used in UPS/DPPT and WDSA, differs from Form 1 amounts because the formula rate calculates Return on Common Equity using a stated Return on Equity of 9.3 percent times the Common Stock Capitalization ratio at the last day of the previous year	(c)	36
5,6	204, 206	Electric Plant in Service Plant investment used in UPS/DPPT 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

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
--	---	---------------------------------------	----------------------------------

FOOTNOTE DATA

7	204, 206	Electric Plant in Service Plant investment used in UPS/DPPT 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	(b)	4, 86-95
8	206	Electric Plant in Service Plant investment used in UPS/DPPT 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
9	219	Accumulated Provision for Depreciation APD used in UPS/DPPT 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
10	227	Materials and Supplies Costs used in UPS/DPPT 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
11	227	Materials and Supplies Costs used in UPS/DPPT differ from Form 1 amounts because the formula rate only reflects the Materials and Supplies related to the Designated Generating Unit at the last day of the previous month	(c)	12, 16
12	234	Accumulated Deferred Income Taxes(Account 190) Costs used in UPS/DPPT 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
13	262	Taxes Accrued, Prepaid and Charged During Year Costs used in UPS/DPPT differ from Form 1 amounts because the formula rate allocates Corporate Franchise Taxes based on a Plant Ratio	(d)	18
14	262	Taxes Accrued, Prepaid and Charged During Year Costs used in UPS/DPPT differ from Form 1 amounts because the formula rate only reflects the ad valorem	(d)	17

Name of Respondent		This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.		(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2015/Q4
FOOTNOTE DATA				
		taxes related to the Designated Generating Unit		
15	262	Taxes Accrued, Prepaid and Charged During Year Costs used in UPS/DPPT differ from Form 1 amounts because the formula rates calculate State and Federal income taxes using the incremental statutory rate	(d)	2, 9
16	262	Taxes Accrued, Prepaid and Charged During Year Costs used in UPS/DPPT differ from Form 1 amounts because the formula rate allocates Payroll Taxes based on a Labor Ratio	(d)	3, 4, 10
17	266	Accumulated Deferred Investment Tax Credits Costs used in UPS/DPPT 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
18	275	Accumulated Deferred Income Taxes (Account 282) Costs used in UPS/DPPT 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
19	277	Accumulated Deferred Income Taxes (Account 283) Costs used in UPS/DPPT 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
20, 21, 22	320-321	Electric Operation and Maintenance Expense Costs used in UPS/DPPT 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
23	321	Electric Operation and Maintenance Expense Costs used in UPS/DPPT 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	(c)	93, 107
FERC FORM NO. 1 (ED. 12-87)		Page 450.3		

Name of Respondent		This Report is:	Date of Report	Year/Period of Report
Entergy	Arkansas, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2015/Q4
FOOTNOTE DATA				
24	323	the Designated Generating Unit Electric Operation and Maintenance Expenses Costs used in UPS/DPPT differ from Form 1 amounts because the formula rate allocate A&G costs using a Labor Ratio	(c)	181-184 and 186-193
25	323	Electric Operation and Maintenance Expense Costs used in UPS/DPPT differ from Form 1 amounts because the formula rate only reflects the Insurance Expense related to the Designated Generating Unit	(c)	185
26	336	Depreciation Expense Costs used in UPS/DPPT 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
27	336	Depreciation Expense Costs used in UPS/DPPT 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
28	110-111	Comparative Balance Sheet The Materials and Supplies balance used in the WDSA differs from the Form 1 amounts because formula rate uses the 13 month average of the balance	(c)	48, 52, 54
29	110-111	Comparative Balance Sheet The Prepayments balance used in the WDSA differs from the Form 1 amounts because formula rate uses the 13 month average of the prepaid taxes and insurance balance excluding retail regulatory commission fees and expenses	(c)	57
30	114	Statement of Income for the Year Taxes Other than Income used in the WDSA differ from Form 1 amounts because the formula rate adjusts for regulatory deferrals	(c)	14
31	206 - 207	Electric Plant in Service Transmission Plant in Service in the WDSA differs from Form 1 amounts because the formula rate adjusts for regional Transmission market labor, IPP prepayments (AFUDC capitalized) and non-retail specifically assigned Transmission	(g)	58
FERC FORM NO. 1 (ED. 12-87)				
Page 450.4				

Name of Respondent		This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.		(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2015/Q4
FOOTNOTE DATA				
		Plant in Service		
32	206 - 207	Electric Plant in Service Distribution Plant in Service in the WDSA differs from Form 1 amounts because the formula rate adjusts for non-retail specifically assigned Distribution Plant in Service	(g)	75
33	206-207	Electric Plant in Service Distribution Plant in Service in the WDSA differs from Form 1 amounts because the formula rate directly assigns the distribution Plant in Service balance to be customer specific (EAI to AECC)	(g)	75
34	206-207	Electric Plant in Service Distribution Plant in Service in the WDSA differs from Form 1 amounts because the formula rate allocates a portion of the total plant in service to Wholesale	(g)	75
35	219	Accumulated Provision for Depreciation (Account 108) Distribution Accumulated Depreciation in the WDSA differs from Form 1 amounts because the formula rate directly assigns the distribution Plant in Service balance to be customer specific (EAI to AECC)	(b)	26
36	219	Accumulated Provision for Depreciation (Account 108) Distribution Accumulated Depreciation in the WDSA differs from Form 1 amounts because the formula rate allocates a portion of the total accumulated depreciation to Wholesale	(b)	26
37	219	Accumulated Provision for Depreciation (Account 108) General Accumulated Depreciation in the WDSA differs from Form 1 amounts because the formula rate adjusts for the timing difference related to the FERC approved increase to non-production depreciate rates used in wholesale-related filings	(b)	28
38	262-263	Taxes Accrued, Prepaid and Charged During Year Base payroll related tax expense in the WDSA differs from Form 1 amounts because the formula rate adjusted employment taxes (Acct 408110) for regulatory deferrals	(d)	7
39	262-263	Taxes Accrued, Prepaid and Charged During Year Retail related Taxes Other than	(d), (i)	14, 18
FERC FORM NO. 1 (ED. 12-87)		Page 450.5		

Name of Respondent		This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.		(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2015/Q4
FOOTNOTE DATA				
		Income Taxes in the WDSA differs from Form 1 amounts because the formula rate includes Non-Income Tax - City Occupation Tax		
40	274-277	Accumulated Deferred Income Taxes ADIT in the WDSA differs from Form 1 amounts because the formula rate reduces the balance for any amounts associated with non-retail allocation of any plant in service amount for which the retail portion has been securitized and other amounts not included for cost-of-service purposes	(k)	9
41	274-277	Accumulated Deferred Income Taxes ADIT in the WDSA differs from Form 1 amounts because the formula rate allocates a portion of the total accumulated depreciation to Wholesale	(k)	9
42	300	Electric Operating Revenues Distribution Related Revenue in the WDSA differs from Form 1 amounts because the formula rate only includes revenues from distribution - rent from electric property and pole attachments rent.	(b)	19
43	300	Electric Operating Revenues General Plant Related Revenue in the WDSA differs from Form 1 amounts because the formula rate only includes revenues from general plant - rent from electric property.	(b)	19
44	322	Electric Operation and Maintenance Expenses Total Distribution Expense (Accts 580 - 598) in the WDSA differs from Form 1 amounts because the formula rate adjusts for regulatory deferrals	(b)	156
1	323	Electric Operation and Maintenance Expenses Total A&G Expense (Accts 920 - 935) in the WDSA differs from Form 1 amounts because the formula rate adjusts for regulatory deferrals	(b)	197
2	336	Depreciation and Amortization of Electric Plant Total Distribution Depreciation Expense in the WDSA differs from Form 1 amounts because the formula rate adjusts for non-retail specifically assigned distribution plant in service	(f)	8
3	336	Depreciation and Amortization of Electric Plant	(f)	8
FERC FORM NO. 1 (ED. 12-87)		Page 450.6		

Name of Respondent		This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.		(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2015/Q4
FOOTNOTE DATA				
		Total Distribution Depreciation Expense in the WDSA differs from Form 1 amounts because the formula rate allocates a portion of the total accumulated depreciation to Wholesale		
4	336	Depreciation and Amortization of Electric Plant Total Other Production Plant Depreciation Expense in the WDSA differs from Form 1 amounts because the formula rate adjusts for regulatory deferrals	(f)	10
5	354	Distribution of Salaries and Wages Production Labor in the WDSA differs from Form 1 amounts because the formula rate adjusts for regulatory deferrals	(b)	20
6	354	Distribution of Salaries and Wages Transmission Labor in the WDSA differs from Form 1 amounts because the formula rate adjusts for regional Transmission market labor and regulatory deferrals	(b)	21
7	354	Distribution of Salaries and Wages Distribution Labor in the WDSA differs from Form 1 amounts because the formula rate adjusts for regulatory deferrals	(b)	23
8	354	Distribution of Salaries and Wages Customer Accounts, Customer Service and Informational Labor in the WDSA differs from Form 1 amounts because the formula rate adjusts for regulatory deferrals	(b)	24-25
9	355	Distribution of Salaries and Wages Total Labor (including Nuclear and Non-Nuclear affiliate) in the WDSA differs from Form 1 amounts because the formula rate adjusts for regulatory deferrals	(b)	96

Name of Respondent Entergy Arkansas, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report / /	Year/Period of Report End of <u>2015/Q4</u>
--	---	-----------------------	--

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.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

1. None
2. None
3. None
4. None
5. None
6. See Entergy Arkansas's 2015 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. The Company and the Union agreed to a new contract effective October 1, 2015 through October 1, 2018. Effective October 1, 2015, the wage increase was 2.25%.

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. The Company and the Union agreed to a new contract effective October 1, 2015 through October 1, 2018. Effective October 1, 2015, the wage increase was 2.25%.

Effective April 1, 2015, executive and senior management, middle management, professionals, and non-represented operating, maintenance, and support staff pay increases averaged approximately 2.5%.

Arkansas Nuclear One

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. The Company and the Union agreed to a new contract effective March 1, 2015 through March 1, 2018. Effective March 1, 2015, the wage increase was 2.25%.

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 April 1, 2013 through March 31, 2016. Effective April 1, 2015, the wage increase was 2.0%.
9. See Entergy Corporation and Subsidiaries 2015 Form 10-K Part I, Legal Proceedings.
10. None
11. Not applicable
12. See Entergy Arkansas's 2015 FERC Form 1 Notes to Financial Statements.
13. See Entergy Arkansas's 2015 FERC Form 1 pages 104 and 105 for Officer and Director changes that occurred in 2015.
14. Not applicable

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	9,651,728,574	9,249,726,334
3	Construction Work in Progress (107)	200-201	403,206,466	297,264,853
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		10,054,935,040	9,546,991,187
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	4,358,957,417	4,227,173,294
6	Net Utility Plant (Enter Total of line 4 less 5)		5,695,977,623	5,319,817,893
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202-203	74,736,794	62,014,852
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)		198,364,093	224,305,313
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	-13,240,078	-7,375,640
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		286,340,965	293,695,805
14	Net Utility Plant (Enter Total of lines 6 and 13)		5,982,318,588	5,613,513,698
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		488,569	1,757,046
19	(Less) Accum. Prov. for Depr. and Amort. (122)		124,214	117,951
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	292,089	-176,530
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)		0	4,700
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		783,513,089	782,082,530
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)		784,169,533	783,549,795
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		8,938,023	10,372,462
36	Special Deposits (132-134)		20,000	20,000
37	Working Fund (135)		82,822	105,452
38	Temporary Cash Investments (136)		0	207,900,851
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		107,632,631	96,309,604
41	Other Accounts Receivable (143)		84,216,327	110,268,504
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		34,226,253	32,246,828
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		32,984,346	32,187,106
45	Fuel Stock (151)	227	56,824,236	48,344,089
46	Fuel Stock Expenses Undistributed (152)	227	5,807,518	2,359,731
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	152,185,399	145,003,434
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	57,172	194,411

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	17,733,783	17,788,971
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)		6,573,243	7,742,713
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	10,049
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		73,582,864	80,704,406
62	Miscellaneous Current and Accrued Assets (174)		67,897,446	30,149,925
63	Derivative Instrument Assets (175)		7,866,710	734,873
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)		588,176,267	757,949,753
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		27,407,015	28,792,987
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	1,353,056,901	1,545,599,821
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	122,418
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)		-36,056	227,094
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	14,424,665	16,528,749
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)		22,972,524	26,162,596
82	Accumulated Deferred Income Taxes (190)	234	194,762,986	626,265,380
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,612,588,035	2,243,699,045
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		8,967,252,423	9,398,712,291

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

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

Includes removal costs accrual of \$85,688,908.

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

Includes removal costs accrual of \$58,998,924.

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	1,308,828,821	1,239,462,910
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-6,134,171	-4,166,662
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)		2,007,958,681	1,940,560,279
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	2,110,000,000	2,110,000,000
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	283,150,901	283,116,985
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		2,756,995	2,938,083
24	Total Long-Term Debt (lines 18 through 23)		2,390,393,906	2,390,178,902
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		91,836,189	136,915,221
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		4,043,413	4,442,457
29	Accumulated Provision for Pensions and Benefits (228.3)		22,327,326	67,215,746
30	Accumulated Miscellaneous Operating Provisions (228.4)		1,508,999	1,246,999
31	Accumulated Provision for Rate Refunds (229)		1,027,611	343,564
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)		872,345,818	818,351,331
35	Total Other Noncurrent Liabilities (lines 26 through 34)		993,089,356	1,028,515,318
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		177,757,613	174,998,290
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		131,736,153	87,293,475
41	Customer Deposits (235)		118,340,183	115,647,132
42	Taxes Accrued (236)	262-263	-29,583,181	-3,333,569
43	Interest Accrued (237)		18,457,263	34,357,215
44	Dividends Declared (238)		1,718,306	1,718,306
45	Matured Long-Term Debt (239)		0	0

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)		18,011,463	15,663,264
48	Miscellaneous Current and Accrued Liabilities (242)		18,722,793	2,682,981
49	Obligations Under Capital Leases-Current (243)		106,864,371	88,351,442
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)		562,024,964	517,378,536
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		8,664,634	540,198
57	Accumulated Deferred Investment Tax Credits (255)	266-267	36,506,379	37,707,662
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	485,870,093	567,226,315
60	Other Regulatory Liabilities (254)	278	306,023,030	288,006,056
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)		1,723,016,437	1,678,095,477
64	Accum. Deferred Income Taxes-Other (283)		453,704,943	950,503,548
65	Total Deferred Credits (lines 56 through 64)		3,013,785,516	3,522,079,256
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		8,967,252,423	9,398,712,291

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 column in 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	2,238,447,202	2,157,316,443		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,449,501,530	1,330,506,949		
5	Maintenance Expenses (402)	320-323	248,291,316	212,229,378		
6	Depreciation Expense (403)	336-337	228,189,209	217,581,119		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	2,101,936	1,650,230		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	15,791,076	16,971,491		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	1,438,231	1,014,837		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		10,524,914	16,258,037		
13	(Less) Regulatory Credits (407.4)		48,560,002	49,398,760		
14	Taxes Other Than Income Taxes (408.1)	262-263	99,762,175	91,270,597		
15	Income Taxes - Federal (409.1)	262-263	38,695,912	-26,213,470		
16	- Other (409.1)	262-263	4,461,189	-2,687,308		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	1,323,251,596	1,025,037,894		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	1,333,331,696	916,705,077		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,226,569	-1,275,537		
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)		62	218		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		50,414,391	46,972,372		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,089,305,146	1,963,212,534		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		149,142,056	194,103,909		

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 purchases, 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		Line No.
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)	
2,238,447,202	2,157,316,443					2
						3
1,449,501,530	1,330,506,949					4
248,291,316	212,229,378					5
228,189,209	217,581,119					6
2,101,936	1,650,230					7
15,791,076	16,971,491					8
1,438,231	1,014,837					9
						10
						11
10,524,914	16,258,037					12
48,560,002	49,398,760					13
99,762,175	91,270,597					14
38,695,912	-26,213,470					15
4,461,189	-2,687,308					16
1,323,251,596	1,025,037,894					17
1,333,331,696	916,705,077					18
-1,226,569	-1,275,537					19
						20
						21
62	218					22
						23
50,414,391	46,972,372					24
2,089,305,146	1,963,212,534					25
149,142,056	194,103,909					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL		Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
			Current Year (c)	Previous Year (d)		
27	Net Utility Operating Income (Carried forward from page 114)		149,142,056	194,103,909		
28	Other Income and Deductions					
29	Other Income					
30	Nonutility 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)		6,015	5,226		
35	Nonoperating Rental Income (418)			60,000		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-1,967,162	-3,227,670		
37	Interest and Dividend Income (419)		22,639,946	23,071,056		
38	Allowance for Other Funds Used During Construction (419.1)		15,881,522	10,788,835		
39	Miscellaneous Nonoperating Income (421)		1,740,840	2,404,004		
40	Gain on Disposition of Property (421.1)		460,456	14,009		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		38,749,587	33,105,008		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			32,067		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		2,051,972	1,739,747		
46	Life Insurance (426.2)					
47	Penalties (426.3)		157,117	3,353		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,492,969	2,420,324		
49	Other Deductions (426.5)		6,480,065	11,140,037		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		11,182,123	15,335,528		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263				
53	Income Taxes-Federal (409.2)	262-263	8,630,131			
54	Income Taxes-Other (409.2)	262-263	1,751,647	2,419,862		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	812,086			
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	7,792,584			
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)		3,401,280	2,419,862		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		24,166,184	15,349,618		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		97,360,507	85,227,937		
63	Amort. of Debt Disc. and Expense (428)		2,057,530	1,889,485		
64	Amortization of Loss on Reaquired Debt (428.1)		3,190,072	3,224,785		
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)		16,185	11,779		
68	Other Interest Expense (431)		5,005,883	3,134,515		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		8,593,559	5,427,173		
70	Net Interest Charges (Total of lines 62 thru 69)		99,036,618	88,061,328		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		74,271,622	121,392,199		
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)		74,271,622	121,392,199		

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		1,239,462,910	1,131,716,202
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)		76,238,784	124,619,869
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		(10,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			(10,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		347	59
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,308,828,821	1,239,462,910
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

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)		1,308,828,821	1,239,462,910
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-4,166,662	(938,933)
50	Equity in Earnings for Year (Credit) (Account 418.1)		-1,967,162	(3,227,670)
51	(Less) Dividends Received (Debit)		347	59
52				
53	Balance-End of Year (Total lines 49 thru 52)		-6,134,171	(4,166,662)

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

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

For the Year Ended December 31, 2015

\$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, 2014

\$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 =====

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)	74,271,622	121,392,199
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	297,934,843	284,190,049
5	Amortization of Debt Discount and Premium on Debt	5,247,602	5,114,270
6			
7			
8	Deferred Income Taxes (Net)	-17,060,598	108,332,817
9	Investment Tax Credit Adjustment (Net)	-1,226,569	-1,275,537
10	Net (Increase) Decrease in Receivables	20,814,955	13,984,336
11	Net (Increase) Decrease in Inventory	-19,054,711	-19,672,849
12	Net (Increase) Decrease in Allowances Inventory	137,239	-84,165
13	Net Increase (Decrease) in Payables and Accrued Expenses	-47,689,287	-115,800,673
14	Net (Increase) Decrease in Other Regulatory Assets	192,542,920	-452,275,066
15	Net Increase (Decrease) in Other Regulatory Liabilities	18,016,974	33,858,684
16	(Less) Allowance for Other Funds Used During Construction	15,881,522	10,788,835
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
19	Other Working Capital	-22,618,777	59,337,256
20	Other	-134,800,586	267,639,115
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	350,634,105	293,951,601
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-624,546,389	-535,348,674
27	Gross Additions to Nuclear Fuel	-132,251,503	-195,091,939
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-15,881,522	-10,788,835
31	Other (provide details in footnote):		
32	Decommissioning Trust Funds	-10,403,061	-8,572,511
33	Proceeds from Sale of Nuclear Fuel	127,164,396	243,829,394
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-624,155,035	-484,394,895
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	-201,477	-115,733
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)		

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	Insurance Proceeds	11,653,989	36,600,000
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	Other (provide details in footnote):		
54	Changes in Money Pool Receivable - Net	2,217,922	15,313,172
55	Other	4,700	205,301
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-610,479,901	-432,392,155
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		617,465,340
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	Changes in Money Pool Payable - Net	52,741,724	
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	52,741,724	617,465,340
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		-365,013,995
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79	Other	4,619,372	-2,459,802
80	Dividends on Preferred Stock	-6,873,220	-6,873,220
81	Dividends on Common Stock		-10,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	50,487,876	233,118,323
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-209,357,920	94,677,769
87			
88	Cash and Cash Equivalents at Beginning of Period	218,378,765	123,700,996
89			
90	Cash and Cash Equivalents at End of period	9,020,845	218,378,765

Name of Respondent Entergy Arkansas, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report / /	Year/Period of Report End of <u>2015/Q4</u>
--	---	-----------------------	--

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 Commission 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.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

A. CASH FLOW STATEMENT, ADDITIONAL INFORMATION:

Cash and Cash Equivalents at December 31, 2015

Cash (Account 131)	\$8,938,023
Working Fund (Account 135)	<u>82,822</u>
Total Cash and Cash Equivalents	<u>\$9,020,845</u>
	=====

SUPPLEMENTAL DISCLOSURE OF CASH FLOW STATEMENT (in 000s)

Cash paid during the period for:

Interest – net of amt capitalized	\$114,341
Income Taxes	\$102,598

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 2014 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 its 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 is that the consolidated Entergy Arkansas GAAP-basis balance sheet includes the subsidiaries storm cost regulatory asset in regulatory assets and the securitization bonds as long-term debt; whereas the FERC Form 1 amounts are presented net as a component of investment in subsidiary company balance.

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, 2015. 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.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

"Registrant Subsidiaries" when used in these Notes means Entergy Arkansas, Inc., 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 (prior to the completion of the business combination with Entergy 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 Louisiana, Entergy Mississippi, and Entergy Texas generate, transmit, and distribute electric power primarily to retail customers in Arkansas, Louisiana, Mississippi, and Texas, respectively. Entergy 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, including Algiers. Prior to October 1, 2015, Entergy Louisiana was the electric power supplier for Algiers. The Entergy Wholesale Commodities segment derives almost all of its revenue from sales of electric power generated by plants owned by subsidiaries in that segment.

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 nets purchases and sales within the MISO market on an hourly basis and reports 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.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
2015	2.6%	2.3%	3.2%	3.0%	2.6%	2.8%
2014	2.4%	2.2%	2.6%	3.2%	2.5%	3.0%
2013	2.5%	2.2%	2.6%	3.3%	2.5%	2.8%

As of December 31, 2015, construction expenditures included in accounts payable are \$43 million for Entergy Arkansas, \$68.6 million for Entergy Louisiana, \$11.4 million for Entergy Mississippi, \$1.5 million for Entergy New Orleans, \$33.1 million for Entergy Texas, and \$6.8 million for System Energy. As of December 31, 2014, construction expenditures included in accounts payable are \$37.3 million for Entergy Arkansas, \$71.4 million for Entergy Louisiana, \$7.8 million for Entergy Mississippi, \$0.9 million for Entergy New Orleans, \$24.1 million for Entergy Texas, and \$7.7 million for System Energy.

Jointly-Owned Generating Stations

Certain Entergy subsidiaries jointly own electric generating facilities with affiliates or third parties. All parties are required to provide their own financing. The investments, fuel expenses, and other operation and maintenance 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, 2015, 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	839	31.50%	\$134	\$100
	Common Facilities	Coal		15.75%	\$33	\$26
White Bluff	Units 1 and 2	Coal	1,637	57.00%	\$520	\$361
Ouachita (b)	Common Facilities	Gas	489	66.67%	\$170	\$147
Entergy Louisiana -						
Roy S. Nelson	Unit 6	Coal	537	40.25%	\$274	\$185

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Roy S. Nelson	Unit 6 Common Facilities	Coal		17.26%	\$11	\$5
Big Cajun 2	Unit 3	Coal	594	24.15%	\$151	\$109
Ouachita (b)	Common Facilities	Gas	243	33.33%	\$87	\$74
Acadia	Common Facilities	Gas	551	50.00%	\$19	\$—
Entergy Mississippi - Independence	Units 1 and 2 and Common Facilities	Coal	1,681	25.00%	\$258	\$152
Entergy Texas - Roy S. Nelson	Unit 6	Coal	537	29.75%	\$197	\$114
Roy S. Nelson	Unit 6 Common Facilities	Coal		12.75%	\$6	\$2
Big Cajun 2	Unit 3	Coal	594	17.85%	\$113	\$73
System Energy - Grand Gulf	Unit 1	Nuclear	1,409	90.00% (c)	\$4,829	\$2,962

- (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 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.

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 temporary differences between the book and tax basis of assets and liabilities, and for certain losses and 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.

The benefits of investment tax credits are deferred and amortized over the average useful life of the related property, as a reduction of income tax expense, for such credits associated with regulated operations 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 or liability be recorded if it is probable that the currently determinable future increase or decrease in regulatory income tax expense will be recovered from or reimbursed to customers through future rates. The primary source of Entergy's regulatory asset for income taxes is

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

related to the ratemaking treatment of the tax effects of book depreciation for the equity component of AFUDC that has been capitalized to property, plant, and equipment but for which there is no corresponding tax basis. Equity-AFUDC 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 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 for the unrealized gains/(losses) on investment securities. For the 30% interest in River Bend formerly owned by Cajun, Entergy Louisiana has recorded an offsetting amount in other deferred credits for 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.

Equity Method Investments

Entergy owns investments that are accounted for under the equity method of accounting because Entergy's ownership level results in significant influence, but not control, over the investee and its operations. Entergy records its share of the investee's comprehensive earnings and losses in income and as an increase or decrease to the investment

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

account. Any cash distributions are charged against the investment account. Entergy discontinues the recognition of losses on equity investments when its share of losses equals or exceeds its carrying amount for an investee plus any advances made or commitments to provide additional financial support. See Note 14 to the financial statements for additional information regarding Entergy's equity method investments.

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 sale 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. Due to regulatory treatment, an offsetting regulatory asset or liability is recorded for changes in fair value of recognized derivatives for the Registrant Subsidiaries.

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. Changes in the fair value of derivative instruments that are not designated as cash flow hedges are recorded in current-period earnings on a mark-to-market basis.

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 historical prices, bid prices, market quotes, and financial modeling. Considerable judgment is required in developing the estimates

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2015/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 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. 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 and capacity over the remaining life of the assets.

Under generally accepted accounting principles the determination of an asset's recoverability is based on the probability-weighted undiscounted net cash flows expected to be generated by the plant and related assets. Projected net cash flows primarily depend on the status of the operations of the plant and pending legal and state regulatory matters, as well as projections of future revenues and costs over the estimated remaining life of the plant.

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 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.

NOTE 2. RATE AND REGULATORY MATTERS

Regulatory Assets and Regulatory Liabilities

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. Regulatory liabilities represent probable future reductions in revenues associated with amounts that Entergy expects to benefit customers

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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. Details of regulatory liabilities in account 254 are presented on FERC Form 1 page 278.

Fuel and purchased power cost recovery

Entergy Arkansas, 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, 2015 and 2014 that Entergy expects to recover (or return to customers) through fuel mechanisms, subject to subsequent regulatory review.

	<u>2015</u>	<u>2014</u>
	(In Millions)	
Entergy Arkansas (a)	\$57.8	\$209.2
Entergy Louisiana (b)	\$102.9	\$107.1
Entergy Mississippi	(\$107.8)	(\$2.2)
Entergy New Orleans (b)	(\$24.9)	(\$25.1)
Entergy Texas	(\$25.1)	\$11.9

- (a) 2015 and 2014 include respectively \$66.7 million and \$65.9 million for Entergy Arkansas 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 recovered over a period greater than twelve months.
- (b) 2015 and 2014 include \$168.1 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 recovered 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.

In May 2014, Entergy Arkansas filed its annual redetermination of the production cost allocation rider to recover the \$3 million unrecovered retail balance as of December 31, 2013 and the \$67.8 million System Agreement bandwidth

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

remedy payment made in May 2014 as a result of the compliance filing pursuant to the FERC's February 2014 orders related to the bandwidth payments/receipts for the June - December 2005 period. In June 2014 the APSC suspended the annual redetermination of the production cost allocation rider and scheduled a hearing in September 2014. Upon a joint motion of the parties, the APSC canceled the September 2014 hearing and in January 2015 the APSC issued an order approving Entergy Arkansas's request for recovery of the \$3 million under-recovered amount based on the true-up of the production cost allocation rider and the \$67.8 million May 2014 System Agreement bandwidth remedy payment subject to refund with interest, with recovery of these payments concluding with the last billing cycle in December 2015. The APSC also found that Entergy Arkansas is entitled to carrying charges pursuant to the current terms of the production cost allocation rider. Entergy Arkansas made its compliance filing pursuant to the order in January 2015 and the APSC issued its approval order, also in January 2015. The redetermined rate went into effect the first billing cycle of February 2015.

In May 2015, Entergy Arkansas filed its annual redetermination of the production cost allocation rider, which included a \$38 million payment made by Entergy Arkansas as a result of the FERC's February 2014 order related to the comprehensive bandwidth recalculation for calendar year 2006, 2007, and 2008 production costs. The redetermined rate for the 2015 production cost allocation rider update was added to the redetermined rate from the 2014 production cost allocation rider update and the combined rate was effective with the first billing cycle of July 2015. This combined rate was effective through December 2015. The collection of the remainder of the redetermined rate for the 2015 production cost allocation rider update will continue through June 2016.

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 resolved

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 was 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 redetermination of its energy cost rate that was filed in March 2014. 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 redetermination of its 2014 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, Outage, and NRC Reviews**" 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 authorized a base rate increase of \$81 million and included an

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

authorized return on common equity of 9.3%. The order allowed Entergy Arkansas to amortize its human capital management costs over a three-and-a-half year period, but also ordered Entergy Arkansas to file a detailed report of the Arkansas-specific costs, savings and final payroll changes upon conclusion of the human capital management strategic imperative. The detailed report was subsequently filed in February 2015. The substance of the report was addressed in Entergy Arkansas's 2015 base rate filing. New rates under the January 2014 order were implemented in the first billing cycle of March 2014 and were 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 considering the additional evidence identified by Entergy Arkansas. In August 2014 the APSC issued an order amending certain aspects of the original order, including providing for a 9.5% authorized return on common equity. Pursuant to the August 2014 order, revised rates were effective for all bills rendered after December 31, 2013 and were implemented in the first billing cycle of October 2014.

2015 Base Rate Filing

In April 2015, Entergy Arkansas filed with the APSC for a general change in rates, charges, and tariffs. The filing notified the APSC of Entergy Arkansas's intent to implement a forward test year formula rate plan pursuant to Arkansas legislation passed in 2015, and requested a retail rate increase of \$268.4 million, with a net increase in revenue of \$167 million. The filing requested a 10.2% return on common equity. In May 2015 the APSC issued an order suspending the proposed rates and tariffs filed by Entergy Arkansas and establishing a procedural schedule to complete its investigation of Entergy Arkansas's application. In September 2015, APSC staff and intervenors filed direct testimony, with the APSC staff recommending a revenue requirement of \$217.9 million and a 9.65% return on common equity. Entergy Arkansas filed rebuttal testimony in October 2015. In December 2015, Entergy Arkansas, the APSC staff, and certain of the intervenors in the rate case filed with the APSC a joint motion for approval of a settlement of the case that proposes a retail rate increase of approximately \$225 million with a net increase in revenue of approximately \$133 million; an authorized return on common equity of 9.75%; and a formula rate plan tariff that provides a 50 basis point band around the 9.75% allowed return on common equity.

A hearing was held in January 2016. In February 2016 the APSC approved the settlement with one exception that would reduce the retail rate increase proposed in the settlement by \$5 million. The parties were directed to inform the APSC by filing no later than February 26, 2016 whether they accept the APSC's proposed settlement agreement modification or request a full hearing on the issues. Entergy Arkansas plans to make its first formula rate plan filing in July 2016 for rates effective with the first billing cycle of January 2017.

A significant portion of the rate increase is related to Entergy Arkansas's acquisition of Union Power Station Power Block 2 for an expected base purchase price of \$237 million, subject to adjustment. The acquisition closed on March 4, 2016. The recovery of the costs to acquire Power Block 2 of the Union Power Station will be through Entergy Arkansas's new base rates that will commence with the first billing cycle of April 2016.

System Agreement Cost Equalization Proceedings

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 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.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 March 2015, in light of the December 2014 decision by the D.C. Circuit in the interruptible load proceeding, Entergy filed with the FERC a motion to establish briefing schedule on refund issues and an initial brief addressing refund issues. The initial brief argued that the FERC, in response to the D.C. Circuit decision, should clarify its policy on refunds and find that refunds are not required in this proceeding. In October 2015 the FERC issued three orders related to the commencement of the remedy on June 1, 2005 and the inclusion of interest on the amount for the period June 1, 2005 through December 31, 2005. Specifically, the FERC rejected Entergy Services's request for rehearing of its decision to include interest on the amount for the seven-month period. The FERC also rejected Entergy Services's request for rehearing of the order rejecting the compliance filing with regard to the issue of interest. Finally, the FERC set for hearing and settlement procedures the 2014 compliance filing that included the bandwidth calculation for the seven months June 1, 2005 through December 31, 2005. In setting the compliance filing for hearing, the FERC rejected the APSC's protest that Entergy Arkansas should not be subject to the filing because Entergy Arkansas would be making the payments during a period following its exit from the System Agreement. The hearing on the bandwidth calculation for the seven months June 1, 2005 through December 31, 2005 is scheduled to occur in July 2016.

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)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Entergy Arkansas	\$156
Entergy Louisiana	(\$75)
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 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.

In February 2014 the FERC issued a rehearing order addressing its October 2011 order. The FERC denied the LPSC's request for rehearing on the issues of whether the bandwidth remedy should be made effective earlier than June 1, 2005, and whether refunds should be ordered for the 20-month refund effective period. The FERC granted the LPSC's rehearing request on the issue of interest on the bandwidth payments/receipts for the June - December 2005 period, requiring that interest be accrued from June 1, 2006 until the date those bandwidth payments/receipts are made. Also in February 2014 the FERC issued an order rejecting the December 2011 compliance filing that calculated the bandwidth payments/receipts for the June - December 2005 period. The FERC order required a new compliance filing that calculates the bandwidth payments/receipts for the June - December 2005 period based on monthly data for the seven individual months including interest pursuant to the February 2014 rehearing order. Entergy has sought rehearing of the February 2014 orders with respect to the FERC's determinations regarding interest. In April 2014 the LPSC filed a petition for review of the FERC's October 2011 and February 2014 orders with the U.S. Court of Appeals for the D.C. Circuit. The appeal is pending.

In April and May 2014, Entergy filed with the FERC an updated compliance filing that provides the payments and receipts among the Utility operating companies pursuant to the FERC's February 2014 orders. The filing shows the following net payments and receipts, including interest, among the Utility operating companies:

	Payments (Receipts)
	(In Millions)
Entergy Arkansas	\$68
Entergy Louisiana	(\$10)
Entergy Mississippi	(\$11)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Entergy New Orleans	\$2
Entergy Texas	(\$49)

These payments were made in May 2014. The LPSC, City Council, and APSC have filed protests.

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	2014
	(In Millions)							
Entergy Arkansas	\$252	\$252	\$390	\$41	\$77	\$41	\$—	\$—
Entergy Louisiana	(\$211)	(\$160)	(\$247)	(\$22)	(\$12)	(\$41)	\$—	\$—
Entergy Mississippi	(\$41)	(\$20)	(\$24)	(\$19)	(\$40)	\$—	\$—	\$—
Entergy New Orleans	\$—	(\$7)	\$—	\$—	(\$25)	\$—	(\$15)	(\$15)
Entergy Texas	(\$30)	(\$65)	(\$119)	\$—	\$—	\$—	\$15	\$15

The Utility operating companies record, as necessary, accounts payable or accounts receivable to reflect the rough production cost equalization payments and receipts required to implement the FERC's remedy. When accounts payable are recorded, a corresponding regulatory asset is recorded for the right to collect the payments from customers. When accounts receivable are recorded, a corresponding regulatory liability is recorded for the obligations to pass the receipts on to customers. As discussed below, no payments and receipts were required in 2015 to implement the FERC's remedy based on calendar year 2014 production costs. Entergy Arkansas ceased participating in the System Agreement on December 18, 2013 and was not part of the calendar year 2013 or 2014 production costs calculations.

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 is recovering its 2013 rough production cost equalization payment over three years beginning April 2014. Entergy Texas included its 2014 rough production cost equalization payment as component of an interim fuel refund made in 2014. 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.

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

In July 2014 the FERC issued four orders in connection with various Service Schedule MSS-3 rough production cost equalization formula compliance filings and rehearing requests. Specifically, the FERC accepted Entergy Services'

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

revised methodologies for calculating certain cost components of the formula and affirmed its prior ruling requiring interest on the true-up amounts. The FERC directed that a comprehensive recalculation of the formula be performed for the filing years 2007, 2008, and 2009 based on calendar years 2006, 2007, and 2008 production costs. In September 2014, Entergy filed with the FERC its compliance filing that provides the payments and receipts, including interest, among the Utility operating companies pursuant to the FERC's orders for the 2007, 2008, and 2009 rate filing proceedings. The filing shows the following additional payments/receipts among the Utility operating companies:

	Payments (Receipts)
	(In Millions)
Entergy Arkansas	\$38
Entergy Louisiana	(\$38)
Entergy Mississippi	\$16
Entergy New Orleans	(\$1)
Entergy Texas	(\$15)

Entergy Arkansas and Entergy Mississippi made the payments in September and October 2014.

The FERC proceedings that resulted from rate filings made in 2007, 2008, and 2009 have been resolved by various orders issued by the FERC and appellate courts. See below for a discussion of rate filings since 2009 and the comprehensive recalculation filing directed by the FERC in the proceeding related to the 2010 rate filing.

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 was held in March 2014 and the presiding ALJ issued an initial decision in September 2014. Briefs on exception were filed in October 2014. In December 2015 the FERC issued an order affirming the initial decision in part and rejecting the initial decision in part. Among other things, the December 2015

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

order directs Entergy Services to submit a compliance filing, the results of which may affect the rough production cost equalization filings made for the June - December 2005, 2006, 2007, and 2008 test periods. In January 2016 the LPSC, the APSC, and Entergy Services filed requests for rehearing of the FERC's December 2015 order. In February 2016, Entergy Services submitted the compliance filing ordered in the December 2015 order. The result of the true-up payments and receipts for the recalculation of production costs resulted in the following payments/receipts among the Utility operating companies:

	Payments (Receipts)
	(In Millions)
Entergy Arkansas	\$2
Entergy Louisiana	\$6
Entergy Mississippi	(\$4)
Entergy New Orleans	(\$1)
Entergy Texas	(\$3)

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. In March 2014 the Fifth Circuit rejected the LPSC's petition for a writ of mandamus. In December 2014 the FERC rescinded its earlier abeyance order and consolidated the 2011 rate filing with the 2012, 2013, and 2014 rate filings for settlement and hearing procedures. See discussion below regarding the consolidated settlement and hearing procedures in connection with this proceeding.

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. In December 2014 the FERC rescinded its earlier abeyance order and consolidated the 2012 rate filing with the 2011, 2013, and 2014 rate filings for settlement and

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

hearing procedures. See discussion below regarding the consolidated settlement and hearing procedures in connection with this proceeding.

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. In December 2014 the FERC rescinded its earlier abeyance order and consolidated the 2013 Rate Filing with the 2011, 2012, and 2014 Rate Filings for settlement and hearing procedures. See discussion below regarding the consolidated settlement and hearing procedures in connection with this proceeding.

2014 Rate Filing Based on Calendar Year 2013 Production Costs

In May 2014, Entergy filed with the FERC the 2014 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. In December 2014 the FERC issued an order accepting the 2014 rates, effective June 1, 2014, subject to refund, set the proceeding for hearing procedures, and consolidated the 2014 Rate Filing with the 2011, 2012, and 2013 Rate Filings for settlement and hearing procedures. See discussion below regarding the consolidated settlement and hearing procedures in connection with this proceeding.

Consolidated 2011, 2012, 2013, and 2014 Rate Filing Proceedings

As discussed above, in December 2014 the FERC consolidated the 2011, 2012, 2013, and 2014 rate filings for settlement and hearing procedures. In May 2015, Entergy filed direct testimony in the consolidated rate filings and the LPSC filed direct testimony concerning its complaint proceeding that is consolidated with the rate filings, challenging certain components of the pending bandwidth calculations for prior years. In July 2015 the parties filed direct and answering testimony. Among other issues with the pending bandwidth calculations, the LPSC challenged the administration of the accounting for joint account sales of energy in the intra-system bill. In August and September 2015 the parties filed additional rounds of testimony in the consolidated hearing for the 2011, 2012, 2013, and 2014 rate filings. In October 2015 the LPSC withdrew its testimony challenging the accounting for joint account sales of energy. The hearings occurred in November 2015, and an initial decision from the ALJ is expected in July 2016.

2015 Rate Filing Based on Calendar Year 2014 Production Costs

In May 2015, Entergy filed with the FERC the 2015 rates in accordance with the FERC's orders in the System Agreement proceeding. The filing showed that no payments and receipts were required in 2015 to implement the FERC's

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

remedy based on calendar year 2014 production costs. Several parties intervened in the proceeding and the LPSC and City Council intervened and filed comments. In October 2015 the FERC accepted the 2015 rates for filing, suspended them for a nominal period, to become effective June 1, 2015, as requested, subject to refund, and set them for hearing and settlement judge procedures.

Calendar Year 2015 Production Costs

Entergy preliminarily estimates that no payments and receipts are required in 2016 to implement the FERC's remedy based on calendar year 2015 production costs. The actual payments/receipts for 2016, based on calendar year 2015 production costs, will not be calculated until the Utility operating companies' 2015 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. The calculation based on 2015 production costs will be the last rough production cost equalization filing submitted by the Utility operating companies because the System Agreement will terminate at the end of August 2016.

Utility Operating Company Termination of System Agreement Participation

Entergy Arkansas and Entergy Mississippi ceased participating in the System Agreement effective December 18, 2013 and November 7, 2015, respectively. Entergy Louisiana, Entergy New Orleans, and Entergy Texas will terminate participation in the System Agreement on August 31, 2016, which will result in the termination of the System Agreement in its entirety pursuant to a settlement agreement approved by the FERC in December 2015.

In connection with the System Agreement termination settlement agreement, it was determined that the purchase power agreements, referred to as the jurisdictional separation plan PPAs, between Entergy Texas and Entergy Gulf States Louisiana that were put in place for certain legacy gas units at the time of Entergy Gulf States's separation into Entergy Texas and Entergy Gulf States Louisiana will terminate effective with System Agreement termination. Similarly, the PPA between Entergy Gulf States Louisiana and Entergy Texas for the Calcasieu unit also will terminate. Currently, the jurisdictional separation plan PPAs are the means by which Entergy Texas receives payment for its receivable associated with Entergy Louisiana's Spindletop gas storage facility regulatory asset. As a result of the System Agreement termination settlement agreement, effective with the termination date, Entergy Texas will no longer receive payments from Entergy Louisiana related to the Spindletop storage facility which resulted in a write-off recorded in 2015 by Entergy Texas of \$23.5 million (\$15.3 million net-of-tax).

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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.

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 July 2011 the refunds made in the fourth quarter 2009 described above were reversed. 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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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. Oral argument was held on the appeal in the D.C. Circuit in September 2014. In December 2014 the D.C. Circuit issued an order on the LPSC’s appeal and remanded the case back to the FERC. The D.C. Circuit rejected the LPSC’s argument that there is a presumption in favor of refunds, but it held that the FERC had not adequately explained its decision to deny refunds and directed the FERC “to consider the relevant factors and weigh them against one another.” In March 2015, Entergy filed with the FERC a motion to establish a briefing schedule on remand and an initial brief on remand to address the December 2014 decision by the D.C. Circuit. The initial brief on remand argued that the FERC, in response to the D.C. Circuit decision, should clarify its policy on refunds and find that refunds are not required in the interruptible load proceeding. The matter 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. In July 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 explained that the FERC already had determined that Entergy Arkansas’s short-term wholesale sales did not trigger the “right-of-first-refusal” provision of the

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 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, excluding interest, 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, excluding interest,

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 in the calculation proceeding. 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 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.

NOTE 3. INCOME TAXES

Details regarding income taxes are presented on FERC Form 1 pages 261-267 and 274-277.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Carryovers

The Registrant Subsidiaries' estimated tax attributes carryovers and their expiration dates as of December 31, 2015 are as follows:

	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
Federal net operating losses	\$7 million	\$2.4 billion	—	—	—	\$242 million
Year(s) of expiration	2030-2035	2035	N/A	N/A	N/A	2030-2035
State net operating losses	—	\$2.5 billion	—	\$6 million	—	\$833 million
Year(s) of expiration	N/A	2035	N/A	2032	N/A	2035
Misc. federal credits	\$1 million	—	\$1 million	—	—	\$1 million
Year(s) of expiration	2029-2033	N/A	2029-2034	N/A	N/A	2029-2033
State credits	—	—	—	—	\$3.3 million	\$6 million
Year(s) of expiration	N/A	N/A	N/A	N/A	2026	2017-2020

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 2015, 2014, and 2013 is as follows:

2015	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
(In Thousands)						

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2015/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

payments

2013	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
(In Thousands)						
Gross balance at January 1, 2013	\$344,669	\$1,002,394	\$16,841	\$52,018	\$13,954	\$260,346
Additions based on tax positions related to the current year	6,427	17,887	957	583	2,170	4,170
Additions for tax positions of prior years	1,228	125,214	401	3,506	587	8,391
Reductions for tax positions of prior years	(3,943)	(53,473)	(1,941)	(962)	(4,186)	(967)
Settlements	(668)	(15,342)	(72)	(3,466)	492	(6,755)
Gross balance at December 31, 2013	347,713	1,076,680	16,186	51,679	13,017	265,185
Offsets to gross unrecognized tax benefits:						
Loss carryovers	(345,674)	(747,756)	(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

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

	December 31,		
	2015	2014	2013
(In Millions)			
Entergy Arkansas	\$4.5	\$2.6	\$0.6
Entergy Louisiana	\$692.7	\$267.3	\$131.9
Entergy Mississippi	\$8.1	\$3.9	\$3.9
Entergy New Orleans	\$50.7	\$50.7	\$—
Entergy Texas	\$5.2	\$10.5	\$10.1
System Energy	\$0.7	\$3.7	\$3.3

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:

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

	December 31,		
	2015	2014	2013
	(In Millions)		
Entergy Arkansas	\$1.3	\$17.0	\$15.2
Entergy Louisiana	\$9.3	\$22.2	\$18.0
Entergy Mississippi	\$0.4	\$2.8	\$2.1
Entergy New Orleans	\$1.8	\$1.3	\$0.9
Entergy Texas	\$1.2	\$1.0	\$0.8
System Energy	\$0.7	\$23.8	\$19.0

Income Tax Audits

Entergy and its subsidiaries file U.S. federal and various state and foreign income tax returns. IRS examinations are complete for years before 2010. All state taxing authorities' examinations are completed for years before 2009.

2006-2007 IRS Audit

In the first quarter 2015, the IRS finalized tax and interest computations from the 2006-2007 audit that resulted in a reversal of Entergy's provision for uncertain tax positions related to accrued interest of approximately \$20 million, including decreases of approximately \$4 million for Entergy Arkansas, \$11 million for Entergy Louisiana, and \$1 million for System Energy.

2008-2009 IRS Audit

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 disagreed with the IRS's disallowance of the 2009 CAM and filed a protest with the IRS Appeals Division in October 2013.

In August 2015, Entergy and the IRS agreed on the treatment of the 2009 position regarding nuclear decommissioning liabilities from the 2008-2009 audit. The agreement provides that Entergy is entitled to deduct approximately \$118 million of the \$9.3 billion claimed in 2009. The agreement effectively settled all matters pertaining

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

to the 2009 tax year and increased Entergy's 2009 federal income tax liability by \$2.4 million.

2010-2011 IRS Audit

The IRS examination of the 2010 and 2011 years is ongoing and the audit field work is expected to be completed by the end of the first quarter of 2016. The IRS has not issued any significant notices of proposed adjustments other than for the decommissioning liability position discussed above. The Revenue Agent's Report is expected to be received shortly after the completion of field work.

Other Tax Matters

Entergy regularly negotiates with the IRS to achieve settlements. The resolution of audit issues could result in significant changes to the amounts of unrecognized tax benefits in the next twelve months.

In September 2013 the U.S. Treasury Department and the IRS issued final regulations that provide guidance on the deductibility and capitalization of costs incurred associated with tangible property. Entergy and the Registrant Subsidiaries filed with the IRS an automatic application for change in accounting method which is in compliance with the final regulations and the safe harbor provisions of the relevant IRS Revenue Procedures. Entergy estimates that the effect of this accounting method change will result in a net increase to Entergy's taxable income of approximately \$585 million, which will be recognized generally over a four year period beginning with the tax year ended 2014. The adoption of the final regulations and safe harbor method results in approximate changes in the Registrant Subsidiaries taxable income as follows: an increase of \$177 million for Entergy Arkansas, an increase of \$78 million for Entergy Louisiana, an increase of \$26 million for Entergy Mississippi, an increase of \$183 million for Entergy Texas, a decrease of \$2 million for Entergy New Orleans, and an increase of \$22 million for System Energy.

The Protecting Americans from Tax Hikes Act of 2015 was enacted in December 2015. The most significant provisions affecting Entergy and the Registrant Subsidiaries were a five-year extension of bonus depreciation and permanent extension of the research and experimentation tax credit. The effect of the bonus depreciation extension on 2015 increased Entergy's tax net operating loss.

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

Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, and Entergy Texas each had credit facilities available as of December 31, 2015 as follows:

Company	Expiration Date	Amount of Facility	Interest Rate (a)	Amount Drawn as of December 31, 2015	Letters of Credit Outstanding as of December 31, 2015
Entergy Arkansas	April 2016	\$20 million (b)	1.92%	—	—

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Entergy Arkansas	August 2020	\$150 million (c)	1.92%	—	—
Entergy Louisiana	August 2020	\$350 million (d)	1.67%	—	\$3.1 million
Entergy Mississippi	May 2016	\$10 million (e)	1.92%	—	—
Entergy Mississippi	May 2016	\$20 million (e)	1.92%	—	—
Entergy Mississippi	May 2016	\$35 million (e)	1.92%	—	—
Entergy Mississippi	May 2016	\$37.5 million (e)	1.92%	—	—
Entergy New Orleans	November 2018	\$25 million	2.17%	—	—
Entergy Texas	August 2020	\$150 million (f)	1.92%	—	\$1.3 million

- (a) The interest rate is the rate as of December 31, 2015 that would be applied to outstanding borrowings under the facility.
- (b) Borrowings under this Entergy Arkansas credit facility may be secured by a security interest in its accounts receivable at Entergy Arkansas's option.
- (c) The credit facility allows Entergy Arkansas to issue letters of credit against 50% of the borrowing capacity of the facility.
- (d) The credit facility allows Entergy Louisiana to issue letters of credit against 50% of the borrowing capacity of the facility.
- (e) Borrowings under the Entergy Mississippi credit facilities may be secured by a security interest in its accounts receivable at Entergy Mississippi's option.
- (f) The credit facility allows Entergy Texas to issue letters of credit against 50% of the borrowing capacity of the facility.

The commitment fees on the credit facilities range from 0.125% to 0.275% of the undrawn commitment amount. Each of the credit facilities requires the Registrant Subsidiary borrower to maintain a debt ratio of 65% or less of its total capitalization. Each Registrant Subsidiary is in compliance with this covenant.

In addition, Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, and Entergy Texas each entered into one or more uncommitted standby letter of credit facilities as a means to post collateral to support its obligations related to MISO. Following is a summary of the uncommitted standby letter of credit facilities as of December 31, 2015:

Company	Amount of Uncommitted Facility	Letter of Credit Fee	Letters of Credit Issued as of December 31, 2015
Entergy Arkansas	\$25 million	0.70%	\$1.0 million
Entergy Louisiana	\$125 million	0.70%	\$17.1 million
Entergy Mississippi	\$40 million	0.70%	\$6.0 million
Entergy New Orleans	\$15 million	0.75%	\$1.4 million
Entergy Texas	\$50 million	0.70%	\$9.4 million

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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, 2017. In addition to borrowings from commercial banks, these companies may also 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 short-term 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, 2015 (aggregating both money pool and external short-term borrowings) for the Registrant Subsidiaries:

	<u>Authorized</u>	<u>Borrowings</u>
	(In Millions)	
Entergy Arkansas	\$250	\$52.7
Entergy Louisiana	\$450	—
Entergy Mississippi	\$175	—
Entergy New Orleans	\$100	—
Entergy Texas	\$200	\$22.1
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 2018.

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, 2015, 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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

and distributions from subsidiaries totaling \$615 million in 2015, \$893 million in 2014, and \$702 million in 2013.

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, Outage, and NRC Reviews

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 approximately \$95 million. 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. In February 2014 the APSC approved Entergy Arkansas’s request to exclude from the calculation of its revised energy cost rate \$65.9 million of deferred fuel and purchased energy costs incurred in 2013 as a result of the ANO stator incident. The APSC authorized Entergy Arkansas to retain the \$65.9 million in its deferred fuel balance with recovery to be reviewed in a later period after more information regarding various claims associated with the ANO stator incident is available.

Entergy Arkansas is pursuing 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. During 2014, Entergy Arkansas collected \$50 million from NEIL. In July 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 contractor, and certain individuals asserting claims of breach of contract, negligence, and gross negligence in connection with their responsibility for the stator drop.

Shortly after the stator incident, the NRC deployed an augmented inspection team to review the plant’s response. In July 2013 a second team of NRC inspectors visited ANO to evaluate certain items that were identified as requiring

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

follow-up inspection to determine whether performance deficiencies existed. In March 2014 the NRC issued an inspection report on the follow-up inspection that discussed two preliminary findings, one that was preliminarily determined to be “red with high safety significance” for Unit 1 and one that was preliminarily determined to be “yellow with substantial safety significance” for Unit 2, with the NRC indicating further that these preliminary findings may warrant additional regulatory oversight. This report also noted that one additional item related to flood barrier effectiveness was still under review.

In May 2014 the NRC met with Entergy during a regulatory conference to discuss the preliminary red and yellow findings and Entergy’s response to the findings. During the regulatory conference, Entergy presented information on the facts and assumptions the NRC used to assess the potential findings. The NRC used the information provided by Entergy at the regulatory conference to finalize its decision regarding the inspection team’s findings. In a letter dated June 23, 2014, the NRC classified both findings as “yellow with substantial safety significance.” In an assessment follow-up letter for ANO dated July 29, 2014, the NRC stated that given the two yellow findings, it determined that the performance at ANO is in the “degraded cornerstone column,” or column 3, of the NRC’s reactor oversight process action matrix beginning the first quarter 2014. Corrective actions in response to the NRC’s findings have been taken and remain ongoing at ANO.

In September 2014 the NRC issued an inspection report on the flood barrier effectiveness issue that was still under review at the time of the March 2014 inspection report. While Entergy believes that the flood barrier issues that led to the finding have been addressed at ANO, NRC processes still required that the NRC assess the safety significance of the deficiencies. In its September 2014 inspection report, the NRC discussed a preliminary finding of “yellow with substantial safety significance” for the Unit 1 and Unit 2 auxiliary and emergency diesel fuel storage buildings. The NRC indicated that these preliminary findings may warrant additional regulatory oversight. Entergy requested a public regulatory conference regarding the inspection, and the conference was held in October 2014. During the regulatory conference, Entergy presented information related to the facts and assumptions used by the NRC in arriving at its preliminary finding of “yellow with substantial safety significance.” In January 2015 the NRC issued its final risk significance determination for the flood barrier violation originally cited in the September 2014 report. The NRC’s final risk significance determination was classified as “yellow with substantial safety significance.”

In March 2015 the NRC issued a letter notifying Entergy of its decision to move ANO into the “multiple/repetitive degraded cornerstone column” (Column 4) of the NRC’s Reactor Oversight Process Action Matrix. Placement into Column 4 requires significant additional NRC inspection activities at the ANO site, including a review of the site’s root cause evaluation associated with the flood barrier and stator issues, an assessment of the effectiveness of the site’s corrective action program, an additional design basis inspection, a safety culture assessment, and possibly other inspection activities consistent with the NRC’s Inspection Procedure. Entergy Arkansas incurred incremental costs of approximately \$53 million in 2015 to prepare for the NRC inspection that began in early 2016. Excluding remediation and response costs that may result from the additional NRC inspection activities, Entergy Arkansas also expects to incur approximately \$50 million in 2016 in support of NRC inspection activities and to implement Entergy Arkansas’s performance improvement initiatives developed in 2015. A much lesser amount of incremental expenses is expected to be ongoing annually after 2016.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Nuclear Fuel Enrichment Contracts

Entergy subsidiaries are parties to two contracts with American Centrifuge Enrichment, LLC (ACE) under which these subsidiaries purchase nuclear fuel enrichment services. The term of each contract is from 2011 to 2022; however, each contract provided for cancellation of the parties' purchase and sale obligations for 2016-2022 if, by August 1, 2014, ACE's planned Advanced Centrifuge Plant was not in commercial operation and ACE did not identify to Entergy's reasonable satisfaction how it would meet its contractual delivery obligations through output from ACE. In August 2014, Entergy sent notice to ACE that the 2016-2022 obligations were canceled by the operation of this contractual provision. United States Enrichment Corporation (USEC), ACE's affiliate to which ACE assigned the contracts, filed a demand for arbitration with the American Arbitration Association, claiming damages of approximately \$165 million. In July 2015 the parties reached an agreement resolving the dispute that resulted in the dismissal of USEC's claims. The resolution of the dispute does not have a material effect on Entergy's results of operations, financial position, or cash flows.

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 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 \$13.5 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. The Terrorism Risk Insurance Reauthorization Act of 2007 expired on December 31, 2014. However, The Terrorism Risk Insurance Reauthorization Act of 2015 was signed into law by the President of the United

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

States on January 12, 2015 thereby extending the Terrorism Risk Insurance Act for six years until December 31, 2020.

Currently, 103 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 \$13.1 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 and Entergy Louisiana each have two licensed reactors. System Energy has 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). The Entergy Wholesale Commodities segment includes the ownership, operation, and decommissioning of nuclear power reactors and the ownership of the shutdown Indian Point 1 reactor and Big Rock Point facility.

Property Insurance

Entergy's nuclear owner/licensee subsidiaries are members of 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, 2015, Entergy was insured against such losses per the following structures:

Utility Plants (ANO 1 and 2, Grand Gulf, River Bend, and Waterford 3)

- Primary Layer (per plant) - \$1.5 billion per occurrence
- Blanket Excess Layer (shared among the Utility plants) - \$100 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 blanket excess layers with common policies because the policies are issued on a per site basis. Flood and earthquake coverage are excluded from the primary layer's first \$500 million in coverage. Entergy currently purchases flood coverage at Waterford 3 and River Bend for the primary layer's first \$500 million in coverage.

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, 2015, the maximum amounts of such possible assessments per occurrence were as follows:

Assessments

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

(In Millions)

Utility:

Entergy Arkansas	\$44.6
Entergy Louisiana	\$54.7
Entergy Mississippi	\$0.10
Entergy New Orleans	\$0.10
Entergy Texas	N/A
System Energy	\$24.5

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. The Terrorism Risk Insurance Reauthorization Act of 2007 expired on December 31, 2014. The Terrorism Risk Insurance Reauthorization Act of 2015, however, was signed into law by the President of the United States in January 2015 thereby extending the Terrorism Risk Insurance Act for six years until December 31, 2020.

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

“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 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. As discussed above, the Terrorism Risk Insurance Reauthorization Act of 2007 expired on December 31, 2014. However, The Terrorism Risk Insurance Reauthorization Act of 2015 was signed into law by the President of the United States on January 12, 2015 thereby extending the Terrorism Risk Insurance Act for six years until December 31, 2020.

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. Due to the removal of the Vermont Yankee assets from this additional coverage, as of June 1, 2015, two 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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 2015 under the agreement are approximately \$19.2 million for Entergy Arkansas, \$7.7 million for Entergy Louisiana, \$16.5 million for Entergy Mississippi, and \$9.3 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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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:

	<u>December 31,</u>	
	<u>2015</u>	<u>2014</u>
	(In Millions)	
Entergy Arkansas	\$85.7	\$59.0
Entergy Louisiana	(\$68.3)	(\$82.6)
Entergy Mississippi	\$77.5	\$76.3
Entergy New Orleans	\$29.4	\$35.2
Entergy Texas	\$25.8	\$18.9
System Energy	\$54.8	\$55.7

The cumulative decommissioning and retirement cost liabilities and expenses recorded in 2015 by Entergy were as follows:

	<u>Liabilities as of December 31, 2014</u>	<u>Liabilities Incurred (a)</u>	<u>Accretion</u>	<u>Change in Cash Flow Estimate</u>	<u>Spending</u>	<u>Liabilities as of December 31, 2015</u>
	(In Millions)					
Utility:						
Entergy Arkansas	\$818.4	\$3.5	\$50.4	\$—	\$—	\$872.3
Entergy Louisiana	\$950.3	\$1.9	\$51.0	\$24.7	\$—	\$1,027.9
Entergy Mississippi	\$6.8	\$1.1	\$0.4	\$—	\$—	\$8.3
Entergy New Orleans	\$2.5	\$—	\$0.2	\$—	\$—	\$2.7
Entergy Texas	\$4.6	\$1.4	\$0.3	(\$0.2)	\$—	\$6.1
System Energy	\$757.9	\$—	\$48.0	(\$2.5)	\$—	\$803.4

(a) See “**Coal Combustion Residuals**” below for additional discussion regarding the asset retirement obligations related to coal combustion residuals management.

The cumulative decommissioning and retirement cost liabilities and expenses recorded in 2014 by Entergy were as follows:

	<u>Liabilities as of December 31, 2013</u>	<u>Accretion</u>	<u>Change in Cash Flow Estimate</u>	<u>Spending</u>	<u>Liabilities as of December 31, 2014</u>
	(In Millions)				
Utility:					
Entergy Arkansas	\$723.8	\$47.0	\$47.6	\$—	\$818.4

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Entergy Louisiana	\$882.2	\$48.1	\$20.0	\$—	\$950.3
Entergy Mississippi	\$6.4	\$0.4	\$—	\$—	\$6.8
Entergy New Orleans	\$2.3	\$0.2	\$—	\$—	\$2.5
Entergy Texas	\$4.3	\$0.3	\$—	\$—	\$4.6
System Energy	\$616.2	\$41.8	\$99.9	\$—	\$757.9

Nuclear Plant Decommissioning

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 2015 and 2014 Entergy updated decommissioning cost estimates for certain nuclear power plants.

In 2014, Entergy Arkansas recorded a revision to its estimated decommissioning cost liabilities for ANO 1 and ANO 2 as a result of a revised decommissioning cost study. The revised estimates resulted in a \$47.6 million increase in the decommissioning cost liabilities, along with a corresponding increase in the related asset retirement cost assets that will be depreciated over the remaining lives of the units.

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, 2015 are as follows:

	<u>Decommissioning Trust Fair Values</u>	<u>Regulatory Asset (Liability)</u>
	(In Millions)	
Utility:		
ANO 1 and ANO 2	\$771.3	\$280.3
River Bend	\$651.7	(\$26.8)
Waterford 3	\$390.6	\$158.5
Grand Gulf	\$701.5	\$108.6

The fair values of the decommissioning trust funds and the related asset retirement obligation regulatory assets (liabilities) of Entergy as of December 31, 2014 are as follows:

	<u>Decommissioning Trust Fair Values</u>	<u>Regulatory Asset (Liability)</u>
	(In Millions)	
Utility:		
ANO 1 and ANO 2	\$769.9	\$247.6

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Entergy Arkansas, Inc.			2015/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

River Bend	\$637.7	(\$25.5)
Waterford 3	\$383.6	\$145.5
Grand Gulf	\$679.8	\$80.4

Coal Combustion Residuals

In June 2010 the EPA issued a proposed rule on coal combustion residuals (CCRs) that contained two primary regulatory options: (1) regulating CCRs destined for disposal in landfills or received (including stored) in surface impoundments as so-called "special wastes" under the hazardous waste program of RCRA Subtitle C; or (2) regulating CCRs destined for disposal in landfills or surface impoundments as non-hazardous wastes under Subtitle D of RCRA. Under both options, CCRs that are beneficially reused in certain processes would remain excluded from hazardous waste regulation. In April 2015 the EPA published the final CCR rule with the material being regulated under the second scenario presented above - as non-hazardous wastes regulated under RCRA Subtitle D. The final regulations create new compliance requirements including modified storage, new notification and reporting practices, product disposal considerations, and CCR unit closure criteria. Entergy believes that on-site disposal options will be available at its facilities, to the extent needed for CCR that cannot be transferred for beneficial reuse.

NOTE 10. LEASES

General

As of December 31, 2015 the Registrant Subsidiaries had non-cancelable operating leases for equipment, buildings, vehicles, and fuel storage facilities with minimum lease payments as follows (excluding power purchase agreement operating leases, nuclear fuel leases, and the Grand Gulf and Waterford 3 sale and leaseback transactions, all of which are discussed elsewhere):

Operating Leases

Year	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
	(In Thousands)				
2016	\$25,358	\$16,757	\$7,139	\$1,960	\$5,700
2017	18,600	14,245	5,596	1,730	4,841
2018	12,947	12,187	4,946	1,416	4,302
2019	13,555	12,677	4,619	1,233	3,194
2020	7,029	7,107	3,710	1,003	1,666
Years thereafter	28,390	6,903	6,028	1,733	1,695
Minimum lease payments	<u>\$105,879</u>	<u>\$69,876</u>	<u>\$32,038</u>	<u>\$9,075</u>	<u>\$21,398</u>

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

Rental Expenses

<u>Year</u>	<u>Entergy Arkansas</u>	<u>Entergy Louisiana</u>	<u>Entergy Mississippi</u>	<u>Entergy New Orleans</u>	<u>Entergy Texas</u>	<u>System Energy</u>
(In Millions)						
2015	\$13.6	\$21.8	\$5.4	\$1.6	\$4.0	\$2.9
2014	\$12.0	\$20.7	\$4.3	\$1.2	\$3.8	\$2.0
2013	\$12.0	\$21.0	\$4.6	\$1.3	\$4.1	\$2.5

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 \$4.7 million in 2015, \$4.8 million in 2014, and \$8.6 million in 2013 for Entergy Arkansas and \$1.1 million in 2015.

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

Qualified Pension Plans

Entergy has nine qualified pension plans covering substantially all employees. The “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 IV for Non-Bargaining Employees,” and “Entergy Corporation Retirement Plan IV for Bargaining Employees” are non-contributory final average pay plans and provide pension benefits that are based on employees’ credited service and compensation during employment. The “Entergy Corporation Retirement Plan III” is a final average pay plan that provides pension benefits that are based on employees’ credited service and compensation during the final years before retirement and 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. Non-bargaining employees whose most recent date of hire is after June 30, 2014 participate in the “Entergy Corporation Cash Balance Plan for Non-Bargaining Employees.” Certain bargaining employees hired or rehired after June 30, 2014, or such later date provided for in their applicable collective bargaining agreements, participate in the “Entergy Corporation Cash Balance Plan for Bargaining Employees.” The Registrant Subsidiaries participate in these four plans: “Entergy Corporation Retirement Plan for Non-Bargaining Employees,” “Entergy Corporation Retirement Plan for Bargaining Employees,” “Entergy Corporation Cash Balance Plan for Non-Bargaining Employees,” and “Entergy Cash Balance Plan for Bargaining Employees.”

The assets of the seven final average pay qualified pension plans are held in a master trust established by Entergy, and the assets of the two cash balance pension plans are held in a second master trust established by Entergy. Each pension plan has an undivided beneficial interest in each of the investment accounts in its respective

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

master trust that is maintained by a trustee. Use of the master trusts 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 in the master trusts are commingled, the trustee maintains supporting records for the purpose of allocating the trust level equity in net earnings (loss) and the administrative expenses of the investment accounts in each trust to the various participating pension plans in that particular trust. The fair value of the trusts' assets is determined by the trustee and certain investment managers. For each trust, 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 trusts on a pro rata basis.

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 net income and contributions, and are decreased for benefit payments. A plan's investment net income/loss (i.e. interest and dividends, realized and unrealized 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 plans in an amount not less than the minimum required contribution under 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 2015, 2014, and 2013 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:

2015	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
(In Thousands)						
Net periodic pension cost:						
Service cost - benefits earned during the period	\$26,646	\$34,396	\$7,929	\$3,395	\$6,582	\$7,827
Interest cost on projected benefit obligation	61,885	69,465	18,007	8,432	17,414	13,970
Expected return on assets	(80,102)	(90,803)	(24,420)	(10,899)	(24,887)	(18,271)
Recognized net loss	54,254	59,802	14,896	8,053	12,950	13,055

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			

NOTES TO FINANCIAL STATEMENTS (Continued)

Net pension cost	\$62,683	\$72,860	\$16,412	\$8,981	\$12,059	\$16,581
Other changes in plan assets and benefit obligations recognized as a regulatory asset and/or AOCI (before tax)						
Arising this period:						
Net (gain)/loss	\$16,687	\$16,618	\$6,329	\$1,853	(\$4,488)	\$101
Amounts reclassified from regulatory asset and/or AOCI to net periodic pension cost in the current year:						
Amortization of net loss	(54,254)	(59,802)	(14,896)	(8,053)	(12,950)	(13,055)
Total	(\$37,567)	(\$43,184)	(\$8,567)	(\$6,200)	(\$17,438)	(\$12,954)
Total recognized as net periodic pension (income)/cost regulatory asset, and/or AOCI (before tax)	\$25,116	\$29,676	\$7,845	\$2,781	(\$5,379)	\$3,627
Estimated amortization amounts from regulatory asset and/or AOCI to net periodic cost in the following year						
Net loss	\$43,747	\$47,809	\$11,938	\$6,460	\$9,358	\$10,414
2014	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy

(In Thousands)

Net periodic pension cost:

Service cost - benefits earned during the period	\$20,090	\$25,706	\$6,094	\$2,666	\$5,142	\$5,785
Interest cost on projected benefit obligation	59,537	66,984	17,273	8,164	17,746	13,561
Expected return on assets	(73,218)	(83,746)	(22,794)	(10,019)	(23,723)	(16,619)
Amortization of prior service cost	—	—	—	—	—	2

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			

NOTES TO FINANCIAL STATEMENTS (Continued)

Recognized net loss	35,956	40,446	9,415	5,796	9,356	9,500
Net pension cost	\$42,365	\$49,390	\$9,988	\$6,607	\$8,521	\$12,229
Other changes in plan assets and benefit obligations recognized as a regulatory asset and/or AOCI (before tax)						
Arising this period:						
Net loss	\$300,907	\$318,932	\$88,199	\$38,161	\$65,363	\$60,763
Amounts reclassified from regulatory asset and/or AOCI to net periodic pension cost in the current year:						
Amortization of prior service cost	—	—	—	—	—	(2)
Amortization of net loss	(35,956)	(40,446)	(9,415)	(5,796)	(9,356)	(9,500)
Total	\$264,951	\$278,486	\$78,784	\$32,365	\$56,007	\$51,261
Total recognized as net periodic pension cost, regulatory asset, and/or AOCI (before tax)	\$307,316	\$327,876	\$88,772	\$38,972	\$64,528	\$63,490
Estimated amortization amounts from regulatory asset and/or AOCI to net periodic cost in the following year						
Net loss	\$54,254	\$59,802	\$14,896	\$8,053	\$12,950	\$13,055
	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
2013						

(In Thousands)

Net periodic pension cost:

Service cost - benefits earned during the period	\$25,229	\$31,302	\$7,295	\$3,264	\$6,475	\$7,242
Interest cost on projected benefit obligation	54,473	61,598	15,802	7,462	16,303	12,170
Expected return on assets	(66,951)	(76,930)	(21,139)	(9,117)	(22,277)	(17,249)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2015/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

Amortization of prior service cost	23	92	10	2	6	9
Recognized net loss	49,517	57,481	13,189	7,878	13,302	9,560
Curtailment loss	4,938	4,347	767	343	1,559	—
Special termination benefit	1,784	2,439	359	581	855	1,970
Net pension cost	<u>\$69,013</u>	<u>\$80,329</u>	<u>\$16,283</u>	<u>\$10,413</u>	<u>\$16,223</u>	<u>\$13,702</u>

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)	(\$221,844)	(\$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)	(92)	(10)	(2)	(6)	(9)
Amortization of net loss	<u>(49,517)</u>	<u>(57,481)</u>	<u>(13,189)</u>	<u>(7,878)</u>	<u>(13,302)</u>	<u>(9,560)</u>
Total	<u>(\$226,645)</u>	<u>(\$279,417)</u>	<u>(\$65,724)</u>	<u>(\$33,299)</u>	<u>(\$69,080)</u>	<u>(\$45,080)</u>

Total recognized as net periodic pension income, regulatory asset, and/or AOCI (before tax)

	<u>(\$157,632)</u>	<u>(\$199,088)</u>	<u>(\$49,441)</u>	<u>(\$22,886)</u>	<u>(\$52,857)</u>	<u>(\$31,378)</u>
--	--------------------	--------------------	-------------------	-------------------	-------------------	-------------------

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	\$40,295	\$9,421	\$5,802	\$9,363	\$9,510

Qualified Pension Obligations, Plan Assets, Funded Status, and Amounts Recognized in the Balance Sheet for the Registrant Subsidiaries as of December 31, 2015 and 2014

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

2015	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
(In Thousands)						
Change in Projected Benefit Obligation (PBO)						
Balance at beginning of year	\$1,485,718	\$1,666,535	\$432,169	\$202,555	\$418,498	\$334,312
Service cost	26,646	34,396	7,929	3,395	6,582	7,827
Interest cost	61,885	69,465	18,007	8,432	17,414	13,970
Actuarial gain	(87,617)	(101,361)	(25,492)	(12,289)	(36,862)	(23,720)
Benefits paid	(86,121)	(104,325)	(24,009)	(11,029)	(22,005)	(20,847)
Balance at end of year	<u>\$1,400,511</u>	<u>\$1,564,710</u>	<u>\$408,604</u>	<u>\$191,064</u>	<u>\$383,627</u>	<u>\$311,542</u>
Change in Plan Assets						
Fair value of assets at beginning of year	\$977,521	\$1,113,359	\$301,250	\$133,344	\$310,713	\$217,621
Actual return on plan assets	(24,201)	(27,175)	(7,401)	(3,243)	(7,487)	(5,550)
Employer contributions	92,419	89,375	22,457	10,903	17,157	20,782
Benefits paid	(86,121)	(104,325)	(24,009)	(11,029)	(22,005)	(20,847)
Fair value of assets at end of year	<u>\$959,618</u>	<u>\$1,071,234</u>	<u>\$292,297</u>	<u>\$129,975</u>	<u>\$298,378</u>	<u>\$212,006</u>
Funded status	<u>(\$440,893)</u>	<u>(\$493,476)</u>	<u>(\$116,307)</u>	<u>(\$61,089)</u>	<u>(\$85,249)</u>	<u>(\$99,536)</u>
Amounts recognized in the balance sheet (funded status)						
Non-current liabilities	(\$440,893)	(\$493,476)	(\$116,307)	(\$61,089)	(\$85,249)	(\$99,536)
Amounts recognized as regulatory asset						
Net loss	\$684,552	\$687,305	\$190,406	\$95,941	\$159,085	\$159,508
Amounts recognized as AOCI (before tax)						
Net loss	\$—	\$51,733	\$—	\$—	\$—	\$—

2014	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
(In Thousands)						
Change in Projected Benefit Obligation (PBO)						
Balance at beginning of year	\$1,192,640	\$1,341,212	\$345,824	\$163,707	\$356,080	\$270,789
Service cost	20,090	25,706	6,094	2,666	5,142	5,785

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2015/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

Interest cost	59,537	66,984	17,273	8,164	17,746	13,561
Actuarial loss	279,781	294,646	81,600	35,131	58,556	55,410
Benefits paid	(66,330)	(62,013)	(18,622)	(7,113)	(19,026)	(11,233)
Balance at end of year	<u>\$1,485,718</u>	<u>\$1,666,535</u>	<u>\$432,169</u>	<u>\$202,555</u>	<u>\$418,498</u>	<u>\$334,312</u>
Change in Plan Assets						
Fair value of assets at beginning of year	\$896,295	\$1,031,187	\$281,837	\$122,960	\$295,751	\$196,328
Actual return on plan assets	52,092	59,460	16,196	6,988	16,916	11,265
Employer contributions	95,464	84,725	21,839	10,509	17,072	21,261
Benefits paid	(66,330)	(62,013)	(18,622)	(7,113)	(19,026)	(11,233)
Fair value of assets at end of year	<u>\$977,521</u>	<u>\$1,113,359</u>	<u>\$301,250</u>	<u>\$133,344</u>	<u>\$310,713</u>	<u>\$217,621</u>
Funded status	<u>(\$508,197)</u>	<u>(\$553,176)</u>	<u>(\$130,919)</u>	<u>(\$69,211)</u>	<u>(\$107,785)</u>	<u>(\$116,691)</u>
Amounts recognized in the balance sheet (funded status)						
Non-current liabilities	(\$508,197)	(\$553,176)	(\$130,919)	(\$69,211)	(\$107,785)	(\$116,691)
Amounts recognized as regulatory asset						
Net loss	\$722,119	\$741,474	\$198,972	\$102,141	\$176,522	\$172,463
Amounts recognized as AOCI (before tax)						
Net loss	\$—	\$40,748	\$—	\$—	\$—	\$—

Other Postretirement Benefits

Entergy also currently offers retiree medical, dental, vision, and life insurance benefits (other postretirement benefits) for eligible retired employees. Employees who commenced employment before July 1, 2014 and who satisfy certain eligibility requirements (including retiring from Entergy after a certain age and/or years of service with Entergy and immediately commencing their Entergy pension benefit), may become eligible for other postretirement benefits.

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. Entergy Arkansas, Entergy Mississippi, Entergy New Orleans, and Entergy Texas have received regulatory approval to recover accrued other postretirement benefit costs through rates. The LPSC ordered Entergy Louisiana to continue the use of the pay-as-you-go method for ratemaking purposes for postretirement benefits other than pensions. However, the LPSC retains the flexibility to examine individual companies' accounting for other postretirement benefits to determine if special exceptions to this

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

order are warranted. 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 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.

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

Total 2015, 2014, and 2013 other postretirement benefit costs of the Registrant Subsidiaries, including amounts capitalized and deferred, for their employees included the following components:

2015	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
Other postretirement costs:						
Service cost - benefits earned during the period	\$6,957	\$9,893	\$2,028	\$818	\$2,000	\$1,881
Interest cost on APBO	12,518	16,311	3,436	2,608	5,366	2,511
Expected return on assets	(19,190)	—	(6,166)	(4,804)	(10,351)	(3,644)
Amortization of prior credit	(2,441)	(7,467)	(916)	(709)	(2,723)	(1,465)
Recognized net loss	5,356	7,118	860	470	2,740	1,198
Net other postretirement benefit (income)/cost	\$3,200	\$25,855	(\$758)	(\$1,617)	(\$2,968)	\$481

Other changes in plan assets and benefit obligations recognized as a regulatory asset and/or AOCI (before tax)

Arising this period:

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2015/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Prior service credit for the period	(\$18,035)	(\$1,361)	\$—	\$—	\$—	(\$644)
Net (gain)/loss	(11,978)	(47,043)	774	(5,810)	(4,907)	305
Amounts reclassified from regulatory asset and/or AOCI to net periodic pension cost in the current year:						
Amortization of prior service credit	2,441	7,467	916	709	2,723	1,465
Amortization of net loss	(5,356)	(7,118)	(860)	(470)	(2,740)	(1,198)
Total	(\$32,928)	(\$48,055)	\$830	(\$5,571)	(\$4,924)	(\$72)
Total recognized as net periodic other postretirement income/(cost), regulatory asset, and/or AOCI (before tax)	(\$29,728)	(\$22,200)	\$72	(\$7,188)	(\$7,892)	\$409
Estimated amortization amounts from regulatory asset and/or AOCI to net periodic cost in the following year						
Prior service credit	(\$5,472)	(\$7,783)	(\$933)	(\$745)	(\$2,722)	(\$1,570)
Net loss	\$4,256	\$2,926	\$893	\$146	\$2,148	\$1,149

2014	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
------	------------------	-------------------	---------------------	---------------------	---------------	---------------

(In Thousands)

Other postretirement costs:

Service cost - benefits earned during the period	\$5,957	\$9,414	\$1,900	\$868	\$2,378	\$2,058
Interest cost on APBO	12,261	16,642	3,655	2,805	5,652	2,611
Expected return on assets	(19,135)	—	(5,771)	(4,475)	(10,358)	(3,727)
Amortization of prior credit	(2,441)	(5,614)	(915)	(709)	(1,300)	(824)
Recognized net loss	1,267	2,723	149	56	801	443

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2015/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Net other postretirement benefit (income)/cost	(\$2,091)	\$23,165	(\$982)	(\$1,455)	(\$2,827)	\$561
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	\$—	(\$12,845)	\$—	\$—	(\$8,536)	(\$3,845)
Net loss	55,642	61,049	9,525	6,309	24,482	10,596
Amounts reclassified from regulatory asset and/or AOCI to net periodic pension cost in the current year:						
Amortization of prior service credit	2,441	5,614	915	709	1,300	824
Amortization of net loss	(1,267)	(2,723)	(149)	(56)	(801)	(443)
Total	\$56,816	\$51,095	\$10,291	\$6,962	\$16,445	\$7,132
Total recognized as net periodic other postretirement income, regulatory asset, and/or AOCI (before tax)	\$54,725	\$74,260	\$9,309	\$5,507	\$13,618	\$7,693
Estimated amortization amounts from regulatory asset and/or AOCI to net periodic cost in the following year						
Prior service credit	(\$2,441)	(\$7,467)	(\$916)	(\$709)	(\$2,723)	(\$1,465)
Net loss	\$5,356	\$7,118	\$860	\$470	\$2,740	\$1,198

2013

Entergy
Arkansas

Entergy
Louisiana

Entergy
Mississippi

Entergy
New
Orleans

Entergy
Texas

System
Energy

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

(In Thousands)

Other postretirement costs:

Service cost - benefits earned during the period	\$9,619	\$16,451	\$3,246	\$1,752	\$3,760	\$3,580
Interest cost on APBO	13,545	18,374	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 service credit	(689)	(1,450)	(204)	(24)	(501)	(126)
Recognized net loss	7,976	9,648	2,534	1,509	3,744	1,896
Curtailement loss	4,517	3,394	596	354	1,436	760
Net other postretirement benefit cost	<u>\$18,125</u>	<u>\$46,417</u>	<u>\$5,126</u>	<u>\$2,625</u>	<u>\$5,124</u>	<u>\$5,705</u>

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)	(\$27,549)	(\$4,714)	(\$4,469)	(\$5,359)	(\$4,591)
Net loss	(81,236)	(84,681)	(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	1,450	204	24	501	126
Acceleration of prior service credit/(cost) due to curtailement	78	132	20	(4)	62	9
Amortization of net loss	<u>(7,976)</u>	<u>(9,648)</u>	<u>(2,534)</u>	<u>(1,509)</u>	<u>(3,744)</u>	<u>(1,896)</u>
Total	<u>(\$100,062)</u>	<u>(\$120,296)</u>	<u>(\$37,042)</u>	<u>(\$24,466)</u>	<u>(\$43,102)</u>	<u>(\$23,931)</u>

Total recognized as net periodic other postretirement cost, regulatory asset, and/or

	(\$81,937)	(\$73,879)	(\$31,916)	(\$21,841)	(\$37,978)	(\$18,226)
--	------------	------------	------------	------------	------------	------------

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			

NOTES TO FINANCIAL STATEMENTS (Continued)

AOCI (before tax)

Estimated amortization amounts from regulatory asset and/or AOCI to net periodic cost in the following year

Prior service credit	(\$2,441)	(\$5,612)	(\$918)	(\$709)	(\$1,301)	(\$824)
Net loss	\$1,267	\$2,723	\$149	\$56	\$800	\$464

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, 2015 and 2014

2015	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
(In Thousands)						
Change in APBO						
Balance at beginning of year	\$303,716	\$394,946	\$83,162	\$63,779	\$130,145	\$60,754
Service cost	6,957	9,893	2,028	818	2,000	1,881
Interest cost	12,518	16,311	3,436	2,608	5,366	2,511
Plan amendments	(18,035)	(1,361)	—	—	—	(644)
Plan participant contributions	6,818	6,864	1,884	1,259	2,092	1,530
Actuarial gain	(34,217)	(47,043)	(6,407)	(12,118)	(17,052)	(3,973)
Benefits paid	(19,476)	(24,182)	(6,927)	(4,532)	(8,275)	(4,532)
Medicare Part D subsidy received	619	825	206	137	306	118
Balance at end of year	\$258,900	\$356,253	\$77,382	\$51,951	\$114,582	\$57,645
Change in Plan Assets						
Fair value of assets at beginning of year	\$244,191	\$—	\$80,935	\$71,004	\$135,733	\$48,293
Actual return on plan assets	(3,049)	—	(1,015)	(1,504)	(1,794)	(634)
Employer contributions	14,722	17,318	661	3,654	2,618	260
Plan participant contributions	6,818	6,864	1,884	1,259	2,092	1,530
Benefits paid	(19,476)	(24,182)	(6,927)	(4,532)	(8,275)	(4,532)
Fair value of assets at end of year	\$243,206	\$—	\$75,538	\$69,881	\$130,374	\$44,917
Funded status	(\$15,694)	(\$356,253)	(\$1,844)	\$17,930	\$15,792	(\$12,728)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Amounts recognized in the balance sheet

Current liabilities	\$—	(\$18,857)	\$—	\$—	\$—	\$—
Non-current liabilities	(15,694)	(337,396)	(1,844)	17,930	15,792	(12,728)
Total funded status	(\$15,694)	(\$356,253)	(\$1,844)	\$17,930	\$15,792	(\$12,728)

Amounts recognized in regulatory asset

Prior service credit	(\$26,149)	\$—	(\$3,225)	(\$2,917)	(\$11,018)	(\$6,902)
Net loss	77,313	—	18,594	6,458	38,806	19,557
	\$51,164	\$—	\$15,369	\$3,541	\$27,788	\$12,655

Amounts recognized in AOCI (before tax)

Prior service credit	\$—	(\$30,874)	\$—	\$—	\$—	\$—
Net loss	—	70,743	—	—	—	—
	\$—	\$39,869	\$—	\$—	\$—	\$—

2014	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
(In Thousands)						
Change in APBO						
Balance at beginning of year	\$250,734	\$339,066	\$74,539	\$57,874	\$115,418	\$53,051
Service cost	5,957	9,414	1,900	868	2,378	2,058
Interest cost	12,261	16,642	3,655	2,805	5,652	2,611
Plan amendments	—	(12,845)	—	—	(8,536)	(3,845)
Plan participant contributions	5,195	5,071	1,396	1,044	1,655	1,061
Actuarial loss	49,573	61,049	7,939	5,097	21,471	9,524
Benefits paid	(20,984)	(24,625)	(6,589)	(4,131)	(8,333)	(3,858)
Medicare Part D subsidy received	980	1,174	322	222	440	152
Balance at end of year	\$303,716	\$394,946	\$83,162	\$63,779	\$130,145	\$60,754
Change in Plan Assets						
Fair value of assets at beginning of year	\$231,663	\$—	\$73,438	\$66,539	\$131,618	\$48,101
Actual return on plan assets	13,066	—	4,185	3,263	7,347	2,655
Employer contributions	15,251	19,554	8,505	4,289	3,446	334

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2015/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

Plan participant contributions	5,195	5,071	1,396	1,044	1,655	1,061
Benefits paid	(20,984)	(24,625)	(6,589)	(4,131)	(8,333)	(3,858)
Fair value of assets at end of year	\$244,191	\$—	\$80,935	\$71,004	\$135,733	\$48,293
Funded status	(\$59,525)	(\$394,946)	(\$2,227)	\$7,225	\$5,588	(\$12,461)
Amounts recognized in the balance sheet						
Current liabilities	\$—	(\$18,724)	\$—	\$—	\$—	\$—
Non-current liabilities	(59,525)	(376,222)	(2,227)	7,225	5,558	(12,461)
Total funded status	(\$59,525)	(\$394,946)	(\$2,227)	\$7,225	\$5,558	(\$12,461)
Amounts recognized in regulatory asset						
Prior service credit	(\$10,555)	\$—	(\$4,141)	(\$3,626)	(\$13,741)	(\$7,723)
Net loss	94,647	—	18,680	12,738	46,453	20,450
	\$84,092	\$—	\$14,539	\$9,112	\$32,712	\$12,727
Amounts recognized in AOCI (before tax)						
Prior service credit	\$—	(\$36,980)	\$—	\$—	\$—	\$—
Net loss	—	124,904	—	—	—	—
	\$—	\$87,924	\$—	\$—	\$—	\$—

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 2015, 2014, and 2013, was as follows:

	<u>Entergy Arkansas</u>	<u>Entergy Louisiana</u>	<u>Entergy Mississippi</u>	<u>Entergy New Orleans</u>	<u>Entergy Texas</u>
	(In Thousands)				
2015	\$446	\$377	\$235	\$64	\$595
2014	\$754	\$135	\$190	\$95	\$491
2013	\$448	\$163	\$192	\$92	\$1,001

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Included in the 2014 net periodic pension cost above are settlement charges of \$337 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, 2015 and 2014 was as follows:

	<u>Entergy Arkansas</u>	<u>Entergy Louisiana</u>	<u>Entergy Mississippi</u>	<u>Entergy New Orleans</u>	<u>Entergy Texas</u>
	(In Thousands)				
2015	\$4,694	\$2,550	\$2,185	\$468	\$8,832
2014	\$4,495	\$2,851	\$2,128	\$476	\$9,567

The accumulated benefit obligation for their employees for the non-qualified plans as of December 31, 2015 and 2014 was as follows:

	<u>Entergy Arkansas</u>	<u>Entergy Louisiana</u>	<u>Entergy Mississippi</u>	<u>Entergy New Orleans</u>	<u>Entergy Texas</u>
	(In Thousands)				
2015	\$4,495	\$2,538	\$1,802	\$417	\$8,460
2014	\$4,086	\$2,824	\$1,761	\$436	\$9,215

The following amounts were recorded on the balance sheet as of December 31, 2015 and 2014:

<u>2015</u>	<u>Entergy Arkansas</u>	<u>Entergy Louisiana</u>	<u>Entergy Mississippi</u>	<u>Entergy New Orleans</u>	<u>Entergy Texas</u>
	(In Thousands)				
Current liabilities	(\$2,128)	(\$237)	(\$119)	(\$19)	(\$773)
Non-current liabilities	(2,566)	(2,313)	(2,066)	(449)	(8,059)
Total funded status	(\$4,694)	(\$2,550)	(\$2,185)	(\$468)	(\$8,832)
Regulatory asset/(liability)	\$2,356	\$544	\$883	(\$136)	(\$333)
Accumulated other comprehensive income (before taxes)	\$—	\$41	\$—	\$—	\$—
<u>2014</u>	<u>Entergy Arkansas</u>	<u>Entergy Louisiana</u>	<u>Entergy Mississippi</u>	<u>Entergy New Orleans</u>	<u>Entergy Texas</u>
	(In Thousands)				
Current liabilities	(\$347)	(\$259)	(\$119)	(\$23)	(\$753)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2015/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

Non-current liabilities	(4,148)	(2,592)	(2,009)	(453)	(8,814)
Total funded status	(\$4,495)	(\$2,851)	(\$2,128)	(\$476)	(\$9,567)
Regulatory asset/(liability)	\$2,368	\$696	\$942	(\$65)	\$296
Accumulated other comprehensive income (before taxes)	\$—	\$98	\$—	\$—	\$—

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 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 Louisiana recovers other postretirement benefit costs on a pay-as-you-go basis and records the unrecognized prior service cost, gains and losses, and transition obligation for its other postretirement benefit obligation as other comprehensive income. Accounting standards also require 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.

Qualified Pension and Other Postretirement Plans' Assets

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.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

The target asset allocation for pension adjusts dynamically based on the pension plans' funded status. The current targets are shown below. The expectation is that the allocation to fixed income securities will increase as the pension plans' funded status increases. The following ranges were established to produce an acceptable, economically efficient plan to manage around the targets.

The target and range asset allocation for postretirement assets reflects recommendations made in the latest optimization study.

Entergy's qualified pension and postretirement weighted-average asset allocations by asset category at December 31, 2015 and 2014 and the target asset allocation and ranges are as follows:

Pension Asset Allocation	Target	Range	Actual 2015	Actual 2014
Domestic Equity Securities	45%	34% to 53%	45%	45%
International Equity Securities	20%	16% to 24%	19%	19%
Fixed Income Securities	35%	31% to 41%	35%	35%
Other	0%	0% to 10%	1%	1%

Postretirement Asset Allocation	Non-Taxable and Taxable				
	Target	Range	Actual 2015	Actual 2014	
Domestic Equity Securities	39%	34% to 44%	40%	42%	
International Equity Securities	26%	21% to 31%	24%	25%	
Fixed Income Securities	35%	30% to 40%	36%	33%	
Other	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 some 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 assets. 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.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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, 2015, 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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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, 2015, and December 31, 2014, 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 Defined Benefit Pension Plan Trusts

2015	Level 1	Level 2	Level 3	Total
(In Thousands)				
Equity securities:				
Corporate stocks:				
Preferred	\$6,409 (b)	\$— (a)	\$—	\$6,409
Common	686,335 (b)	95	—	686,430
Common collective trusts	—	1,873,218 (c)	—	1,873,218
103-12 investment entities	—	283,288 (h)	—	283,288
Fixed income securities:				
U.S. Government securities	1,879 (b)	343,805 (a)	—	345,684
Corporate debt instruments	—	595,862 (a)	—	595,862
Registered investment companies	255,720 (d)	547,208 (e)	—	802,928
Other	—	114,215 (f)	—	114,215
Other:				
Insurance company general account (unallocated contracts)	—	35,998 (g)	—	35,998
Total investments	\$950,343	\$3,793,689	\$—	\$4,744,032
Cash				373
Other pending transactions				1,124
Less: Other postretirement assets included in total investments				(38,096)
Total fair value of qualified pension assets				\$4,707,433

2014	Level 1	Level 2	Level 3	Total
(In Thousands)				

Equity securities:

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2015/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

Corporate stocks:

Preferred	\$10,017 (b)	\$— (a)	\$—	\$10,017
Common	717,685 (b)	97	—	717,782
Common collective trusts	—	1,886,897 (c)	—	1,886,897
103-12 investment entities	—	259,995	—	259,995

Fixed income securities:

U.S. Government securities	240 (b)	400,059 (a)	—	400,299
Corporate debt instruments	—	548,788 (a)	—	548,788
Registered investment companies	286,534 (d)	576,641 (e)	—	863,175
Other	—	130,295 (f)	—	130,295

Other:

Insurance company general account
(unallocated contracts)

— 37,818 (g) — 37,818

Total investments

\$1,014,476 \$3,840,590 \$— \$4,855,066

Cash 495

Other pending transactions 7,359

Less: Other postretirement assets
included in total investments (34,954)

**Total fair value of qualified pension
assets**

\$4,827,966

Other Postretirement Trusts

2015	Level 1	Level 2	Level 3	Total
(In Thousands)				

Equity securities:

Common collective trust	\$—	\$348,604 (c)	\$—	\$348,604
-------------------------	-----	---------------	-----	-----------

Fixed income securities:

U.S. Government securities	33,789 (b)	42,222 (a)	—	76,011
Corporate debt instruments	—	62,629 (a)	—	62,629
Registered investment companies	3,572 (d)	—	—	3,572
Other	—	49,677 (f)	—	49,677

Total investments

\$37,361 \$503,132 \$— \$540,493

Other pending transactions 480

Plus: Other postretirement assets included
in the investments of the qualified
pension trust 38,096

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

2014	Level 1	Level 2	Level 3	Total
(In Thousands)				
Equity securities:				
Common collective trust	\$—	\$370,228 (c)	\$—	\$370,228
Fixed income securities:				
U.S. Government securities	36,306 (b)	45,618 (a)	—	81,924
Corporate debt instruments	—	57,830 (a)	—	57,830
Registered investment companies	5,558 (d)	—	—	5,558
Other	—	46,968 (f)	—	46,968
Total investments	\$41,864	\$520,644	\$—	\$562,508
Other pending transactions				165
Plus: Other postretirement assets included in the investments of the qualified pension trust				34,954
Total fair value of other postretirement assets				\$597,627

- (a) Certain preferred stocks and certain fixed income debt securities (corporate, government, and securitized) are stated at fair value as determined by broker quotes.
- (b) Common stocks, certain preferred stocks, and certain fixed income debt securities (government) 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 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.
- (h) 103-12 investment entities hold investments in accordance with stated objectives. The investment strategy of the investment entities is to capture the growth potential of international equity markets by replicating the

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

performance of a specified index. Net asset value per share of the 103-12 investment entities estimate fair value.

Accumulated Pension Benefit Obligation

The qualified pension accumulated benefit obligation for each of the Registrant Subsidiaries for their employees as of December 31, 2015 and 2014 was as follows:

	December 31,	
	2015	2014
	(In Thousands)	
Entergy Arkansas	\$1,309,903	\$1,379,108
Entergy Louisiana	\$1,436,535	\$1,523,691
Entergy Mississippi	\$379,775	\$399,300
Entergy New Orleans	\$176,692	\$186,473
Entergy Texas	\$359,687	\$391,296
System Energy	\$286,917	\$305,556

Estimated Future Benefit Payments

Based upon the assumptions used to measure Entergy's qualified pension and other postretirement benefit obligations at December 31, 2015, 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 for their employees will be as follows:

Estimated Future Qualified Pension Benefits Payments	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
	(In Thousands)					
Year(s)						
2016	\$71,847	\$68,238	\$20,061	\$8,094	\$19,442	\$13,043
2017	\$72,566	\$70,537	\$20,805	\$8,426	\$20,185	\$13,320
2018	\$73,854	\$73,422	\$21,544	\$8,902	\$20,955	\$13,791
2019	\$75,442	\$76,224	\$22,237	\$9,321	\$21,604	\$14,153
2020	\$77,137	\$79,554	\$23,168	\$9,910	\$22,438	\$14,950
2021 - 2025	\$423,691	\$460,606	\$127,084	\$58,280	\$123,521	\$89,766

Estimated Future Non-Qualified Pension Benefits Payments	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
---	-----------------------------	------------------------------	--------------------------------	--------------------------------	--------------------------

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

(In Thousands)

Year(s)						
2016	\$2,128	\$237	\$119	\$19	\$773	
2017	\$223	\$230	\$130	\$19	\$731	
2018	\$217	\$222	\$119	\$19	\$702	
2019	\$211	\$214	\$117	\$46	\$680	
2020	\$265	\$206	\$229	\$31	\$751	
2021 - 2025	\$1,579	\$961	\$863	\$218	\$3,255	

**Estimated Future
Other
Postretirement
Benefits Payments
(before Medicare
Part D Subsidy)**

Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
-----------------------------	------------------------------	--------------------------------	--------------------------------	--------------------------	--------------------------

(In Thousands)

Year(s)						
2016	\$16,001	\$18,946	\$4,106	\$3,763	\$6,244	\$3,051
2017	\$15,925	\$19,244	\$4,168	\$3,755	\$6,448	\$3,115
2018	\$16,249	\$20,046	\$4,402	\$3,803	\$6,864	\$3,183
2019	\$16,292	\$20,863	\$4,509	\$3,820	\$7,177	\$3,290
2020	\$16,221	\$21,501	\$4,677	\$3,785	\$7,389	\$3,349
2021 - 2025	\$82,430	\$115,765	\$25,004	\$18,266	\$38,692	\$18,094

**Estimated
Future
Medicare Part D
Subsidy**

Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas	System Energy
-----------------------------	------------------------------	--------------------------------	--------------------------------	--------------------------	--------------------------

(In Thousands)

Year(s)						
2016	\$86	\$89	\$31	\$22	\$36	\$11
2017	\$96	\$99	\$34	\$23	\$39	\$13
2018	\$305	\$313	\$107	\$70	\$120	\$44
2019	\$339	\$344	\$117	\$73	\$128	\$51
2020	\$377	\$380	\$125	\$77	\$137	\$60
2021 - 2025	\$2,422	\$2,487	\$774	\$430	\$832	\$465

Contributions

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

The Registrant Subsidiaries expect to contribute approximately the following to the qualified pension and other postretirement plans for their employees in 2016:

	<u>Entergy Arkansas</u>	<u>Entergy Louisiana</u>	<u>Entergy Mississippi</u>	<u>Entergy New Orleans</u>	<u>Entergy Texas</u>	<u>System Energy</u>
	(In Thousands)					
Pension						
Contributions	\$82,829	\$83,907	\$19,914	\$10,693	\$15,771	\$20,195
Other						
Postretirement						
Contributions	\$4,238	\$18,946	\$—	\$3,669	\$3,231	\$—

Actuarial Assumptions

The significant actuarial assumptions used in determining the pension PBO and the other postretirement benefit APBO as of December 31, 2015 and 2014 were as follows:

	<u>2015</u>	<u>2014</u>
Weighted-average discount rate:		
Qualified pension	4.51% - 4.79% Blended 4.67%	4.03% - 4.40% Blended 4.27%
Other postretirement	4.60%	4.23%
Non-qualified pension	3.84%	3.61%
Weighted-average rate of increase in future compensation levels	4.23%	4.23%
Assumed health care trend rate:		
Pre-65	6.75%	7.10%
Post-65	7.55%	7.70%
Ultimate rate	4.75%	4.75%
Year ultimate rate is reached and beyond:		
Pre-65	2024	2023
Post-65	2024	2023

The significant actuarial assumptions used in determining the net periodic pension and other postretirement benefit costs for 2015, 2014, and 2013 were as follows:

	<u>2015</u>	<u>2014</u>	<u>2013</u>
Weighted-average discount rate:			
Qualified pension	4.03% - 4.40% Blended 4.27%	5.04% - 5.26% Blended 5.14%	4.31% - 4.50% Blended 4.36%

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Other postretirement	4.23%	5.05%	4.36%
Non-qualified pension	3.61%	4.29%	3.37%
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	8.25%	8.50%	8.50%
Other postretirement tax deferred assets	8.05%	8.30%	8.50%
Other postretirement taxable assets	6.25%	6.50%	6.50%
Assumed health care trend rate:			
Pre-65	7.10%	7.25%	7.50%
Post-65	7.70%	7.00%	7.25%
Ultimate rate	4.75%	4.75%	4.75%
Year ultimate rate is reached and beyond:			
Pre-65	2023	2022	2022
Post-65	2023	2022	2022

With respect to the mortality assumptions, Entergy used the RP-2014 Employee and Health Annuitant Tables, with a fully generational MP-2015 projection scale, in determining its December 31, 2015 pension plans' PBOs and other postretirement benefit APBO. The mortality assumption used in determining Entergy's December 31, 2014 pension plans' PBOs and other postretirement benefit APBO was the RP-2014 Employee and Health Annuitant Tables, with a fully generational MP-2014 projection scale.

A one percentage point change in the assumed health care cost trend rate for 2015 would have the following effects for the Registrant Subsidiaries for their employees:

2015	1 Percentage Point Increase		1 Percentage Point Decrease	
	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	\$27,571	\$3,112	(\$22,839)	(\$2,442)
Entergy Louisiana	\$42,312	\$4,132	(\$34,837)	(\$3,274)
Entergy Mississippi	\$9,032	\$850	(\$7,412)	(\$668)
Entergy New Orleans	\$4,741	\$404	(\$3,985)	(\$329)
Entergy Texas	\$13,195	\$1,055	(\$10,991)	(\$851)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

System Energy	\$7,422	\$721	(\$6,085)	(\$570)
---------------	---------	-------	-----------	---------

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 certain of its subsidiaries. The participating employing Entergy subsidiary makes matching contributions to the System Savings Plan for all eligible participating employees in an amount equal to either 70% or 100% of the participants' basic contributions, up to 6% of their eligible earnings per pay period. The matching contribution is allocated to investments as directed by the employee.

The Registrant Subsidiaries' 2015, 2014, and 2013 contributions to defined contribution plans for their employees were as follows:

Year	Entergy Arkansas	Entergy Louisiana	Entergy Mississippi	Entergy New Orleans	Entergy Texas
(In Thousands)					
2015	\$3,242	\$4,324	\$1,920	\$721	\$1,620
2014	\$3,044	\$4,133	\$1,855	\$710	\$1,563
2013	\$3,351	\$4,299	\$1,954	\$769	\$1,616

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Note 15 to the financial statements is not applicable to Entergy Arkansas.

NOTE 16. RISK MANAGEMENT AND FAIR VALUES

Market Risk

In the normal course of business, Entergy is exposed to a number of market risks. Market risk is the potential loss that Entergy may incur as a result of changes in the market or fair value of a particular commodity or instrument. All financial and commodity-related instruments, including derivatives, are subject to market risk including commodity price risk, equity price, and interest rate risk. Entergy uses derivatives primarily to mitigate commodity price risk, particularly power price and fuel price 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 use derivative instruments to hedge the exposure to price volatility inherent in their purchased power, fuel, and gas purchased for resale costs that are recovered from customers.

Entergy's exposure to market risk is determined by a number of factors, including the size, term, composition, and diversification of positions held, as well as market volatility and liquidity. For instruments such as options, the time period during which the option may be exercised and the relationship between the current market price of the underlying instrument and the option's contractual strike or exercise price also affects the level of market risk. A significant factor influencing the overall level of market risk to which Entergy is exposed is its use of hedging techniques to mitigate such risk. Hedging instruments and volumes are chosen based on ability to mitigate risk associated with future energy and capacity prices; however, other considerations are factored into hedge product and volume decisions including corporate liquidity, corporate credit ratings, counterparty credit risk, hedging costs, firm settlement risk, and product availability in the marketplace. Entergy manages market risk by actively monitoring compliance with stated risk management policies as well as monitoring the effectiveness of its hedging policies and strategies. Entergy's risk management policies limit the amount of total net exposure and rolling net exposure during the stated periods. These policies, including related risk limits, are regularly assessed to ensure their appropriateness given Entergy's objectives.

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.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Entergy may use standardized master netting agreements to help mitigate the credit risk of derivative instruments. These master agreements facilitate the netting of cash flows associated with a single counterparty and may include collateral requirements. Cash, letters of credit, and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds an established threshold. The threshold represents an unsecured credit limit, which may be supported by a parental/affiliate guaranty, as determined in accordance with Entergy's credit policy. In addition, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Entergy manages fuel price volatility for its Louisiana jurisdictions (Entergy Louisiana and Entergy New Orleans) and Entergy Mississippi through the purchase of short-term natural gas swaps that financially settle against NYMEX futures. These swaps are marked-to-market through fuel expense with offsetting regulatory assets or liabilities. All benefits or costs of the program are recorded in fuel costs. The notional volumes of these swaps are based on a portion of projected annual exposure to gas for electric generation at Entergy Louisiana and Entergy Mississippi and projected winter purchases for gas distribution at Entergy Louisiana and Entergy New Orleans. The total volume of natural gas swaps outstanding as of December 31, 2015 is 39,816,000 MMBtu for Entergy, including 32,140,000 MMBtu for Entergy Louisiana, 7,010,000 MMBtu for Entergy Mississippi, and 666,000 MMBtu for Entergy New Orleans. Credit support for these natural gas swaps is covered by master agreements that do not require collateralization based on mark-to-market value, but do carry adequate assurance language that may lead to collateralization requests.

During the second quarter 2015, Entergy participated in the annual FTR auction process for the MISO planning year of June 1, 2015 through May 31, 2016. FTRs are derivative instruments which represent economic hedges of future congestion charges that will be incurred in serving Entergy's customer 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, 2015 is 46,355 GWh for Entergy, including 9,726 GWh for Entergy Arkansas, 21,383 GWh for Entergy Louisiana, 6,160 GWh for Entergy Mississippi, 3,517 GWh for Entergy New Orleans, and 5,294 GWh for Entergy Texas. Credit support for FTRs held by the Utility operating companies is covered by cash and/or letters of credit issued by each Utility operating company as required by MISO. Credit support for FTRs held by Entergy Wholesale Commodities is covered by cash. As of December 31, 2014, letters of credit posted with MISO covered the FTR exposure for Entergy Arkansas and Entergy Mississippi. As of December 31, 2015, no cash or letters of credit were required to be posted for FTR exposure for the Utility operating companies or Entergy Wholesale Commodities, respectively.

The fair values of the Registrant Subsidiaries' derivative instruments not designated as hedging instruments on their balance sheets as of December 31, 2015 and 2014 are as follows:

Instrument	Balance Sheet Location	Fair Value (a)	Registrant
(In Millions)			

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

2015

Assets:

FTRs	Prepayments and other	\$7.9	Entergy Arkansas
FTRs	Prepayments and other	\$8.5	Entergy Louisiana
FTRs	Prepayments and other	\$2.4	Entergy Mississippi
FTRs	Prepayments and other	\$1.5	Entergy New Orleans
FTRs	Prepayments and other	\$2.2	Entergy Texas

Liabilities:

Natural gas swaps	Other current liabilities	\$7.0	Entergy Louisiana
Natural gas swaps	Other current liabilities	\$1.3	Entergy Mississippi
Natural gas swaps	Other current liabilities	\$0.5	Entergy New Orleans

2014

Assets:

FTRs	Prepayments and other	\$0.7	Entergy Arkansas
FTRs	Prepayments and other	\$25.5	Entergy Louisiana
FTRs	Prepayments and other	\$3.4	Entergy Mississippi
FTRs	Prepayments and other	\$4.1	Entergy New Orleans
FTRs	Prepayments and other	\$12.3	Entergy Texas

Liabilities:

Natural gas swaps	Other current liabilities	\$15.8	Entergy Louisiana
Natural gas swaps	Other current liabilities	\$2.8	Entergy Mississippi
Natural gas swaps	Other current liabilities	\$0.9	Entergy New Orleans

(a) No cash collateral was required to be posted as of December 31, 2015 and 2014, respectively.

The effects of the Registrant Subsidiaries' derivative instruments not designated as hedging instruments on their income statements for the years ended December 31, 2015, 2014, and 2013 are as follows:

Instrument	Income Statement Location	Amount of gain (loss) recorded in the income statement (In Millions)	Registrant
2015			

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	(a)	(\$33.2)	Entergy Louisiana
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	(a)	(\$6.1)	Entergy Mississippi
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	(a)	(\$1.4)	Entergy New Orleans
FTRs	Purchased power	(b)	\$68.7	Entergy Arkansas
FTRs	Purchased power	(b)	\$55.4	Entergy Louisiana
FTRs	Purchased power	(b)	\$16.5	Entergy Mississippi
FTRs	Purchased power	(b)	\$8.5	Entergy New Orleans
FTRs	Purchased power	(b)	\$16.8	Entergy Texas

2014

Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	(a)	(\$5.5)	Entergy Louisiana
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	(a)	(\$2.5)	Entergy Mississippi
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	(a)	(\$0.2)	Entergy New Orleans
FTRs	Purchased power	(b)	\$21.6	Entergy Arkansas
FTRs	Purchased power	(b)	\$103.5	Entergy Louisiana
FTRs	Purchased power	(b)	\$19.0	Entergy Mississippi
FTRs	Purchased power	(b)	\$16.5	Entergy New Orleans
FTRs	Purchased power	(b)	\$65.8	Entergy Texas

2013

Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	(a)	\$10.5	Entergy Louisiana
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	(a)	\$2.5	Entergy Mississippi
Natural gas swaps	Fuel, fuel-related expenses, and gas purchased for resale	(a)	\$0.1	Entergy New Orleans
FTRs	Purchased power	(b)	(\$0.1)	Entergy Arkansas
FTRs	Purchased power	(b)	\$0.5	Entergy Louisiana
FTRs	Purchased power	(b)	\$1.0	Entergy Mississippi
FTRs	Purchased power	(b)	\$1.2	Entergy New Orleans

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

FTRs Purchased power (b) \$0.8 Entergy Texas

- (a) 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.
- (b) Due to regulatory treatment, the changes in the estimated fair value of FTRs for the Utility operating companies are recorded through purchased power expense 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 for the Utility operating companies are settled are recovered or refunded through fuel cost recovery mechanisms.

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.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

- 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 congestion costs in MISO between applicable generation and load pricing nodes based on the 50th percentile of historical prices. They are classified as Level 3 assets and liabilities. The valuations of these assets and liabilities are performed by the Entergy Wholesale Commodities Risk Control group for the unregulated business and by the System Planning and Operations Risk Control group for the Utility operating companies. The values are calculated internally and verified against the data published by MISO. Entergy's Accounting Policy group reviews these valuations for reasonableness, with the assistance of others within the organization with knowledge of the various inputs and assumptions used in the valuation. The Risk Control groups report to the Vice President and Treasurer. The Accounting Policy group reports to the Chief Accounting Officer.

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, 2015 and December 31, 2014. 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

2015	Level 1	Level 2	Level 3	Total
(In Millions)				

Assets:

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			

NOTES TO FINANCIAL STATEMENTS (Continued)

Decommissioning trust funds (a):

Equity securities	\$3.0	\$464.4	\$—	\$467.4
Debt securities	110.5	193.4	—	303.9
Securitization recovery trust account	4.2	—	—	4.2
Escrow accounts	12.2	—	—	12.2
FTRs	—	—	7.9	7.9
	<u>\$129.9</u>	<u>\$657.8</u>	<u>\$7.9</u>	<u>\$795.6</u>

<u>2014</u>	<u>Level 1</u>	<u>Level 2</u>	<u>Level 3</u>	<u>Total</u>
				(In Millions)
Assets:				
Temporary cash investments	\$208.0	\$—	\$—	\$208.0
Decommissioning trust funds (a):				
Equity securities	7.2	480.1	—	487.3
Debt securities	72.2	210.4	—	282.6
Securitization recovery trust account	4.1	—	—	4.1
Escrow accounts	12.2	—	—	12.2
FTRs	—	—	0.7	0.7
	<u>\$303.7</u>	<u>\$690.5</u>	<u>\$0.7</u>	<u>\$994.9</u>

- (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 to the financial statements 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, 2015.

	<u>Entergy Arkansas</u>	<u>Entergy Louisiana</u>	<u>Entergy Mississippi</u>	<u>Entergy New Orleans</u>	<u>Entergy Texas</u>
					(In Millions)
Balance as of January 1,	\$0.7	\$25.5	\$3.4	\$4.1	\$12.3
Issuances of FTRs	7.0	48.3	5.4	7.3	11.4
Gains (losses) included as a regulatory liability/asset	68.9	(9.9)	10.1	(1.4)	(4.7)
Settlements	(68.7)	(55.4)	(16.5)	(8.5)	(16.8)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			

NOTES TO FINANCIAL STATEMENTS (Continued)

Balance as of December 31, \$7.9 \$8.5 \$2.4 \$1.5 \$2.2

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, 2014.

	<u>Entergy Arkansas</u>	<u>Entergy Louisiana</u>	<u>Entergy Mississippi</u>	<u>Entergy New Orleans</u>	<u>Entergy Texas</u>
	(In Millions)				
Balance as of January 1,	\$—	\$12.4	\$1.0	\$2.0	\$18.4
Issuances of FTRs	4.2	58.8	15.2	8.3	33.2
Gains (losses) included as a regulatory liability/asset	18.1	57.8	6.2	10.3	26.5
Settlements	(21.6)	(103.5)	(19.0)	(16.5)	(65.8)
Balance as of December 31,	<u>\$0.7</u>	<u>\$25.5</u>	<u>\$3.4</u>	<u>\$4.1</u>	<u>\$12.3</u>

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, Grand Gulf, Pilgrim, Indian Point 1 and 2, Vermont Yankee, and Palisades (NYPA currently retains the decommissioning trusts and liabilities for Indian Point 3 and FitzPatrick). 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 30% interest in River Bend formerly owned by Cajun, Entergy Louisiana has recorded an offsetting amount of unrealized gains/(losses) in other deferred credits. 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, 2015 and 2014 are summarized as follows:

<u>Fair Value</u>	<u>Total Unrealized Gains</u>	<u>Total Unrealized Losses</u>
-----------------------	---------------------------------------	--

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

	(In Millions)		
2015			
Equity Securities	\$467.4	\$234.4	\$0.2
Debt Securities	303.9	4.1	2.2
Total	\$771.3	\$238.5	\$2.4
2014			
Equity Securities	\$487.3	\$248.9	\$—
Debt Securities	282.6	6.2	1.1
Total	\$769.9	\$255.1	\$1.1

The amortized cost of debt securities was \$301.8 million as of December 31, 2015 and \$277.4 million as of December 31, 2014. As of December 31, 2015, the debt securities have an average coupon rate of approximately 2.44%, an average duration of approximately 5.14 years, and an average maturity of approximately 5.98 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 equity 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, 2015:

	Equity Securities		Debt Securities	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	(In Millions)			
Less than 12 months	\$7.8	\$0.2	\$111.4	\$1.7
More than 12 months	—	—	18.5	0.5
Total	\$7.8	\$0.2	\$129.9	\$2.2

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, 2014:

	Equity Securities		Debt Securities	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	(In Millions)			
Less than 12 months	\$0.1	\$—	\$56.5	\$0.3

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

More than 12 months	—	—	34.8	0.8
Total	<u>\$0.1</u>	<u>\$—</u>	<u>\$91.3</u>	<u>\$1.1</u>

The fair value of debt securities, summarized by contractual maturities, as of December 31, 2015 and 2014 are as follows:

	<u>2015</u>	<u>2014</u>
	(In Millions)	
less than 1 year	\$1.8	\$14.9
1 year - 5 years	145.2	127.3
5 years - 10 years	138.5	128.2
10 years - 15 years	2.4	1.7
15 years - 20 years	2.0	1.0
20 years+	14.0	9.5
Total	<u>\$303.9</u>	<u>\$282.6</u>

During the years ended December 31, 2015, 2014, and 2013, proceeds from the dispositions of securities amounted to \$213 million, \$181.5 million, and \$266.4 million, respectively. During the years ended December 31, 2015, 2014, and 2013, gross gains of \$5.9 million, \$8.7 million, and \$16.8 million, respectively, and gross losses of \$0.3 million, \$0.3 million, and \$0.6 million, respectively, were recorded in earnings.

Other-than-temporary impairments and unrealized gains and losses

Entergy, Entergy Arkansas, Entergy Louisiana, and System Energy evaluate unrealized losses at the end of each period to determine whether an other-than-temporary impairment has occurred. 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). Entergy did not have any material other-than-temporary impairments relating to credit losses on debt securities for the years ended December 31, 2015, 2014, and 2013. 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. Entergy did not record material charges to other income in 2015, 2014, and 2013, respectively, resulting from the recognition of the other-than-temporary impairment of certain equity securities held in its decommissioning trust funds.

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

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; and receive management, technical, and operating services from Entergy Operations. These transactions are on an "at cost" basis. In addition, Entergy Power sold electricity to Entergy Arkansas, Entergy Louisiana, and Entergy New Orleans prior to the expiration of the contract in 2013.

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.

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

Intercompany Revenues

	<u>Entergy Arkansas</u>	<u>Entergy Louisiana</u>	<u>Entergy Mississippi</u>	<u>Entergy New Orleans</u>	<u>Entergy Texas</u>	<u>System Energy</u>
	(In Millions)					
2015	\$127.9	\$420.2	\$86.0	\$66.1	\$259.1	\$632.4
2014	\$131.2	\$440.2	\$169.8	\$80.1	\$316.1	\$664.4
2013	\$349.9	\$329.5	\$107.3	\$28.1	\$369.4	\$735.1

Intercompany Operating Expenses

	<u>Entergy Arkansas (a)</u>	<u>Entergy Louisiana (b)</u>	<u>Entergy Mississippi</u>	<u>Entergy New Orleans (c)</u>	<u>Entergy Texas</u>	<u>System Energy</u>
	(In Millions)					
2015	\$508.5	\$929.4	\$331.8	\$278.4	\$413.7	\$155.1
2014	\$596.6	\$1,027.6	\$367.6	\$249.5	\$445.3	\$156.7
2013	\$656.1	\$1,171.9	\$399.0	\$288.7	\$418.1	\$175.2

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
NOTES TO FINANCIAL STATEMENTS (Continued)			

- (a) Includes power purchased from Entergy Power of \$3.3 million in 2013. The contract with Entergy Power expired in May 2013.
- (b) Includes power purchased from RS Cogen of \$3.2 million in 2013 and power purchased from Entergy Power of \$8.1 million in 2013. The contract with Entergy Power expired in May 2013.
- (c) Includes power purchased from Entergy Power of \$8 million in 2013. The contract with Entergy Power expired in May 2013.

NOTE 20. QUARTERLY FINANCIAL DATA

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

NOTE 21. SUBSEQUENT EVENTS

Management has evaluated the impact of events occurring after December 31, 2015 up to April 18, 2016, the date that Entergy Arkansas's FERC financial statements and disclosure were filed. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

In March 2016, Entergy Arkansas, Entergy Louisiana and Entergy New Orleans purchased the Union Power Station, a 1,980 MW (summer rating) power generation facility located near El Dorado, Arkansas, from Union Power Partners, L.P. The Union Power Station consists of four natural gas-fired, combined-cycle gas turbine power blocks, each rated at 495 MW (summer rating). Entergy Louisiana purchased two of the power blocks and a 50% undivided ownership interest in certain assets related to the facility, and Entergy Arkansas and Entergy New Orleans each purchased acquire one power block and a 25% undivided ownership interest in such related assets. The aggregate purchase price for the Union Power Station was approximately \$948 million (approximately \$237 million for each power block and associated assets) subject to further adjustment. The FERC, APSC, LPSC, and City Council approved the transaction.

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
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/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					

**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)	9,111,601,099	9,111,601,099
4	Property Under Capital Leases	844,068	844,068
5	Plant Purchased or Sold		
6	Completed Construction not Classified	516,493,584	516,493,584
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	9,628,938,751	9,628,938,751
9	Leased to Others		
10	Held for Future Use	965,381	965,381
11	Construction Work in Progress	403,206,466	403,206,466
12	Acquisition Adjustments	21,824,442	21,824,442
13	Total Utility Plant (8 thru 12)	10,054,935,040	10,054,935,040
14	Accum Prov for Depr, Amort, & Depl	4,358,957,417	4,358,957,417
15	Net Utility Plant (13 less 14)	5,695,977,623	5,695,977,623
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	4,026,451,559	4,026,451,559
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	328,775,543	328,775,543
22	Total In Service (18 thru 21)	4,355,227,102	4,355,227,102
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	3,551,948	3,551,948
33	Total Accum Prov (equals 14) (22,26,30,31,32)	4,358,957,417	4,358,957,417

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/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
					8
					9
					10
					11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

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.

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	57,880,799	11,820,053
4	Allowance for Funds Used during Construction	4,134,053	901,889
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	62,014,852	
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)	224,305,313	76,903,433
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	-7,375,640	-8,014,285
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	293,695,805	
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
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance End of Year (f)	Line No.
Amortization (d)	Other Reductions (Explain in a footnote) (e)		
			1
			2
		69,700,852	3
		5,035,942	4
			5
		74,736,794	6
			7
			8
			9
			10
			11
102,844,653		198,364,093	12
-2,149,847		-13,240,078	13
		286,340,965	14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
FOOTNOTE DATA			

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

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

Investment of River Fuel Trust #1 at December 31, 2015

Investment at December 31, 2014	\$224,305,313
Additional investment in fuel	75,390,730
Daily lease charges allocated to and included in capitalized costs	1,512,703
Less: Burn-up charges paid to lessor	102,844,653
Total Investment at December 31, 2015	----- \$198,364,093 =====

Cost Incurred under River Fuel Trust #1 Lease for the
Year Ended December 31, 2015

Daily Lease Charges	\$5,752,931
Fuel Burn-Up Charges	102,844,653
Total	----- \$108,597,584 =====

As of December 31, 2015, arrangements to lease nuclear fuel existed in an aggregate amount up to \$290 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 2016. The intermediate-term notes issued pursuant to these fuel lease arrangements have varying maturities through July 2021. 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.

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	375,237,616	16,277,024
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	379,103,288	16,277,024
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	2,128,299	
9	(311) Structures and Improvements	68,939,915	494,171
10	(312) Boiler Plant Equipment	438,714,565	26,010,334
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	139,317,933	1,478,994
13	(315) Accessory Electric Equipment	59,740,797	479,883
14	(316) Misc. Power Plant Equipment	13,864,826	126,782
15	(317) Asset Retirement Costs for Steam Production	775,616	3,580,096
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	723,481,951	32,170,260
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	2,648,089	
19	(321) Structures and Improvements	499,585,314	75,557,874
20	(322) Reactor Plant Equipment	1,189,315,278	40,729,021
21	(323) Turbogenerator Units	330,666,021	7,893,407
22	(324) Accessory Electric Equipment	280,845,431	13,628,745
23	(325) Misc. Power Plant Equipment	268,938,433	21,886,305
24	(326) Asset Retirement Costs for Nuclear Production	110,910,357	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	2,682,908,923	159,695,352
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	1,304,463	
28	(331) Structures and Improvements	2,842,630	
29	(332) Reservoirs, Dams, and Waterways	14,996,744	15,058
30	(333) Water Wheels, Turbines, and Generators	17,730,970	-175
31	(334) Accessory Electric Equipment	3,292,920	209,277
32	(335) Misc. Power PLant Equipment	2,194,852	23,647
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)	42,369,920	247,807
36	D. Other Production Plant		
37	(340) Land and Land Rights	2,364,826	
38	(341) Structures and Improvements	269,784,831	2,897,514
39	(342) Fuel Holders, Products, and Accessories	3,779,535	206,411
40	(343) Prime Movers	26,776,246	4,233,249
41	(344) Generators	312,469,013	-70,669
42	(345) Accessory Electric Equipment	4,252,404	535,449
43	(346) Misc. Power Plant Equipment	2,997,958	121,421
44	(347) Asset Retirement Costs for Other Production	23,762	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	622,448,575	7,923,375
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,071,209,369	200,036,794

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	61,092,457	132,695
49	(352) Structures and Improvements	52,522,599	5,318,998
50	(353) Station Equipment	654,478,795	40,420,363
51	(354) Towers and Fixtures	141,567,987	1,238,421
52	(355) Poles and Fixtures	364,338,290	28,857,094
53	(356) Overhead Conductors and Devices	346,638,609	19,515,067
54	(357) Underground Conduit	18,865	
55	(358) Underground Conductors and Devices	39,153	23,745
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)	1,622,596,644	95,506,383
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	8,860,193	41,860
61	(361) Structures and Improvements	20,313,119	1,179,772
62	(362) Station Equipment	383,138,006	21,528,041
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	560,099,346	22,544,863
65	(365) Overhead Conductors and Devices	509,838,163	26,814,583
66	(366) Underground Conduit	95,468,800	4,367,187
67	(367) Underground Conductors and Devices	148,854,610	6,132,226
68	(368) Line Transformers	715,179,618	30,936,967
69	(369) Services	273,861,281	13,788,340
70	(370) Meters	131,817,429	3,582,638
71	(371) Installations on Customer Premises	41,945,013	2,298,847
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	87,275,302	8,823,094
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,976,650,880	142,038,418
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	5,515,738	
87	(390) Structures and Improvements	94,287,102	2,427,319
88	(391) Office Furniture and Equipment	28,599,634	3,699,351
89	(392) Transportation Equipment		
90	(393) Stores Equipment	1,048,714	
91	(394) Tools, Shop and Garage Equipment	15,773,533	974,748
92	(395) Laboratory Equipment	939,354	100,513
93	(396) Power Operated Equipment		
94	(397) Communication Equipment	20,582,945	16,057,222
95	(398) Miscellaneous Equipment	3,619,488	565,560
96	SUBTOTAL (Enter Total of lines 86 thru 95)	170,366,508	23,824,713
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)	170,366,508	23,824,713
100	TOTAL (Accounts 101 and 106)	9,225,975,161	477,683,332
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)	9,225,975,161	477,683,332

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
			391,514,640	4
			395,380,312	5
				6
				7
			2,128,299	8
2,581,199			66,852,887	9
3,482,718			461,242,181	10
				11
129,107			140,667,820	12
687,756		-62,409	59,470,515	13
372,186			13,619,422	14
			4,355,712	15
7,252,966		-62,409	748,336,836	16
				17
			2,648,089	18
1,031,982			574,111,206	19
8,476,027			1,221,568,272	20
3,175,064			335,384,364	21
1,243,473			293,230,703	22
1,014,708			289,810,030	23
			110,910,357	24
14,941,254			2,827,663,021	25
				26
			1,304,463	27
			2,842,630	28
			15,011,802	29
			17,730,795	30
46,614			3,455,583	31
			2,218,499	32
				33
			7,341	34
46,614			42,571,113	35
				36
			2,364,826	37
9,558			272,672,787	38
			3,985,946	39
3,161,037			27,848,458	40
332,066			312,066,278	41
21,612			4,766,241	42
320			3,119,059	43
			23,762	44
3,524,593			626,847,357	45
25,765,427		-62,409	4,245,418,327	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
			61,225,152	48
42,670		663,120	58,462,047	49
3,596,840		-600,711	690,701,607	50
			142,806,408	51
2,298,506			390,896,878	52
699,533			365,454,143	53
			18,865	54
			62,898	55
			1,899,889	56
				57
6,637,549		62,409	1,711,527,887	58
				59
			8,902,053	60
33,251			21,459,640	61
3,394,424			401,271,623	62
				63
365,317			582,278,892	64
8,865,459			527,787,287	65
7,499			99,828,488	66
87,314			154,899,522	67
757,106			745,359,479	68
21,906			287,627,715	69
171,409			135,228,658	70
2,807,639			41,436,221	71
				72
51,797			96,046,599	73
				74
16,563,121			3,102,126,177	75
				76
				77
				78
106,951				79
5,941,521				80
				81
				82
				83
6,048,472				84
				85
543			5,515,195	86
250,628		-55,758	96,408,035	87
17,097,533			15,201,452	88
				89
163,580			885,134	90
1,834,965			14,913,316	91
			1,039,867	92
				93
790,941			35,849,226	94
355,293			3,829,755	95
20,493,483		-55,758	173,641,980	96
				97
				98
20,493,483		-55,758	173,641,980	99
75,508,052		-55,758	9,628,094,683	100
				101
				102
				103
75,508,052		-55,758	9,628,094,683	104

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

Schedule Page: 204 Line No.: 104 Column: c

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

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
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					
41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/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		283,835
3	Land and Land Rights Under \$250,000	Various		461,392
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			965,381

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	STORM DL ARK DIST ICE 2/15-17/2015	4,818,151
3	STORM DL ARK DIST EAI (3/4/15)	2,317,860
4	STORM DL ARK DIST EAI 5/24/15	2,213,645
5	IMPROVE - OH RECONDUCTOR CIRCUIT A1	1,732,224
6	GOV MAND: AHTD 061194 OH ASSOC WITH	1,298,814
7	CUSTOMER REQ - RELOCATE OH FACILITI	1,219,699
8	HIGHWAY: EL DORADO - HWY 335 07028	1,183,242
9	CUSTOMER REQ - RELOCATE OH FACILITI	1,110,020
10	GOVERNMENT MANDATED: AHTD JOB 07028	1,089,902
11	CUSTOMER REQ - RELOCATE OH FACILITI	1,014,862
12	LRAFB PHASE 1B	1,003,490
13	HIGHWAY RELOCATION 012155	967,616
14	LRAFB PHASE 1A	965,644
15	GOV MAND: AHTD CA0501 TURNER RD TO	895,317
16	DISTR PRIVATE AREA LIGHT MTCE EAI	821,285
17	EAI STORM (11/15/15)	774,496
18	STORM DL ARK DIST EAI 2/25/15	748,461
19	GOV MAND: AHTD 100654 HWY 18 IMPROV	718,602
20	PLANNED PROJECT - ST15-007A - DEWIT	622,140
21	EAI STORM (8/5/15)	569,666
22	CUSTOMER REQUEST: UNIVERSITY DRIVE	549,554
23	STORM DL ARK DIST EAI (01/10/15)	548,197
24	STORM DL ARK DIST EAI 6/26/15	515,632
25	IMPROVMENT: LOAD JUSTIFIED CIRCUIT	498,624
26	GOV MAND: AHTD 050263 HWY 64 BEEBE	497,638
27	STORM DL ARK DIST EAI 5/8/15	468,165
28	IMPROVE: CW15-007A N260 HWY 225 REC	464,896
29	REVENUE: AMERICAN SILICA, CAVE CITY	450,990
30	IMPROVE: Y426-RECONDUCTOR HWY 7 NOR	442,854
31	IMPROVE: RECONDUCTOR SIMPSON RD CW1	427,353
32	STORM DL ARK DIST EAI (4/9/15)	388,476
33	IMPROVEMENT-RELOCATE FACILITIES FOR	373,155
34	JOINT T&D CONSTRUCT COFER ROAD SUBS	352,687
35	HIGHWAY: GOVERNMENT MANDATED LIGHTI	348,341
36	HIGHWAY RELOCATION(12155 AHTD JOB)	341,466
37	IMPROVE: CW15005B RECONDUCTOR HWY 6	337,897
38	IMPROVEMENT: HARRISBURG, AR, RECOND	300,553
39	GOVERNMENT MANDATED:AHTD HWY 124 RE	271,039
40	EAI LOAD RESEARCH SAMPLE METERS	267,706
41	CUSTOMER: UNIVERSITY DRIVE-SOUTH	249,611
42	EAI STORM 7/14/15	242,731
43	TOTAL	403,206,466

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	RS15-004A - REPLACE 1.3 MILE OF #6	230,069
2	IMPROVE: PLANNED PROJECT HN15-017S/	229,162
3	AHTD 050249 (REIMB) RELOCATE FACILI	221,801
4	BLYTHEVILLE NE ALT FEEDERS 288 & 10	211,481
5	IMPROVEMENT:MTN VIEW * HWY 5 RECOND	196,827
6	MEMS: CROSS AND 8TH	194,810
7	UPSIZE EXISTING FEEDER TO HANDLE LO	194,366
8	CUSTOMR: CITY OF PINE BLUFF-UNIVERS	193,397
9	SOUTH WESTERN ENERGY,	190,303
10	INTERNAL: RECONDUCTOR J207 TO BACK	179,381
11	CUSTOMR: OH EXT TO ENTERGY TOC (SEC	179,314
12	N429 - ADD A PHASE AND RECLOSER ROC	176,929
13	GOVERNMENT MANDATED: AHTD # 110557,	175,069
14	ALT PROGRAM: SUBSTATION - BLYTHEVIL	165,241
15	IMPROVE: LOAD JUSTIFICATION PROJECT	164,327
16	IMPROVE: OH CW15-012A-SUMMER HWY 65	161,381
17	FOCUS: A144 - 3X08	159,614
18	IMPROVEMENT: JOINT T&D SUMMIT SUBST	157,083
19	GOVERNMENT MANDATED: ARKANSAS HIGH	153,116
20	MOH REVENUE - THIS IS TO RECONDUCTO	151,369
21	IMPROVE: D640: RECONDUCTOR ALONG H	151,350
22	SOUTHWESTERN ENERGY COMPANY,	145,171
23	CW15-012A - SUMMER - ADD 1 MILE OF	140,939
24	GOVERNMENT MANDATED: CITY OF BENTON	139,862
25	FEEDER A165: BACKBONE INSPECTION &	132,746
26	SR15-004A: N429 - (WINTER) RECONDUCT	130,976
27	GARLAND-GAINES NETWORK TIE	129,143
28	2015 FOCUS K210 15206V	128,252
29	EAI STORM BACKUP (CREATED 8/6/15)	126,031
30	L344 TARGETED CIRCUIT JOB	123,420
31	PLANNED PROJECT HN15-020A/S611/6S56	123,349
32	REVENUE: DRIVER FARMS GRAIN BINS, C	121,200
33	IMPROVE: CW15-002A REPLACE REGUALTO	119,888
34	GOV MAND: AHTD 061194 HWY 10 UG CON	119,380
35	IMPROVE - OH RS15-011A WORTHERN RD	118,912
36	BUILD 0.4 MILES 3 PHASE OHD PRI. &	118,066
37	IMPROVE: LOAD JUSTIFICATION PROJECT	115,312
38	BKBONE - MG15-A377	112,391
39	2015 FOCUS V210	108,834
40	2015 FOCUS R220 BREAKER - SWARM REC	103,435
41	UG EXT TO LIV AT RIVERHOUSE APT COM	102,162
42	UNDERGROUND TO OVERLAND PARK SUBDIV	100,960
43	TOTAL	403,206,466

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	OTHER DISTRIBUTION PLANT	5,807,233
2		
3	GENERAL & INTANGIBLE PLANT:	
4	REGULATORY SOFTWARE PROJECT ONE	4,043,571
5	SPO ESI UNION PROJECT	3,306,498
6	ANO1 PHASE II - NFPA 805 TRANSITION	2,385,497
7	AMI FOUNDATION PHASE	2,144,123
8	CIP V5 - EAI SUBSTATION SW	1,421,311
9	SOFTWARE/CONSULTING SERV DOE SGIG	1,292,927
10	CDR CASE MGMT/CRM SOFTWARE/IMPL	955,934
11	ANO2 IMPLEMENT LICENSE RENEWAL COMM	891,303
12	CIP V5 CONTROL CENTERS-SOFTWARE	871,647
13	SFTW-HANA BW UPGRADE & UNICODE CONV	826,093
14	DRY FUEL CASK VSC-24 LICENSE RENEWA	768,112
15	ERP REPLACEMENT FINANCE	706,924
16	HIGH VOLTAGE PROTECTION UPLAND	701,518
17	ERP REPLACEMENT HR	680,771
18	HIGH VOLTAGE PROTECTION AECC SITES	649,167
19	SEARCY SC YARD IMPROVEMENTS	615,194
20	2015 DISTR CAP TOOLS/EQUIP EAI	607,339
21	CITRIX PERFORMANCE SOLUTION	582,755
22	PHASE 2: REGULATORY SW PROJECT ONE	578,191
23	RECORD TO REPORT	561,421
24	CORE HR (PAYROLL/ESS/MSS/BENEFITS)	537,286
25	SYNTEMPO/MAXAVERA WORK FLOW TOOL	522,538
26	RISK, LEGAL, MATTER AND SPEND MANAG	509,833
27	TRANSMISSION CODE COMPLIANCE PGM	479,633
28	HIGH VOLTAGE PROTECTION MORRILTON	450,940
29	RUSSELLVILLE SC YARD IMPROVEMENTS	396,417
30	HIGH VOLTAGE PROTECTION - CASH SITE	365,934
31	CUST DIGITAL IVR SOFTWARE/IMPLEMENT	354,836
32	ETA-PC REFRESH REMEDIATION	325,702
33	POWERPLANT UPGRADE SOFTWARE	312,468
34	SOURCE TO PAY	307,335
35	PHASE 2: BUDGET PLAN SW PROJECT ONE	297,573
36	CDR DIGITAL ASSETS SOFTWARE/IMPLEMT	293,189
37	SEARCY SC QUALITY IMPROVEMENTS	272,587
38	SCCM END USER MGMT. INFRA. LRL	271,778
39	Q3-Q4 2015-EAI PC REFRESH	262,788
40	CIP V5 - AR GENERATION HW	241,685
41	MW REP. LEVELIZE 2015 TCB	239,979
42	FINANCE REPORTING	218,967
43	TOTAL	403,206,466

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	AR GRID; PURCHASE POWER CABLES	198,636
2	OIT-FOS-GRC - AIR EMISSIONS	186,062
3	EAI:PURCH TOOLS AND TEST EQUIPMENT	183,775
4	CIPV5-ADVANCED MONITORING TOOLS SFT	178,917
5	2015 - REG.RATE DEV. EAI	177,302
6	2015 ASG MOBIUS REPLACEMENT SW	168,338
7	ACTIVE DIRECTORY UPGRADE EAI	164,650
8	HIGH VOLTAGE PROTECTION 34TH & MAIN	148,669
9	CIP V5 - AR GENERATION SW	141,534
10	HR REPORTING	140,324
11	HIGH VOLTAGE PROTECTION HS CARBIDE	132,108
12	DELL SUB: DOE PROJECT	127,496
13	EL DORADO SUB; DOE PROJECT	126,275
14	WEST HELENA SC QUALITY IMPROVEMENTS	118,030
15	HIGH VOLTAGE PROTECTION NEWELL	112,536
16	HARRISON SC EMERGENCY GENERATOR IMP	109,890
17	HIGH VOLTAGE PROTECTION HS VILLAGE	107,366
18	ORDER TO CASH	104,327
19	EAI STORM WAR ROOM (LRO)	103,916
20	HIGH VOLTAGE PROTECTION LITTLE ROCK	100,394
21	OTHER GENERAL AND INTANGIBLE PLANT	2,959,765
22		
23	PRODUCTION PLANT:	
24	U2 MODS RESULTING FROM NFPA805	17,129,962
25	ANO1 MODS RESULTING FROM NFPA 805	8,195,811
26	ANO DFS (2015/2016 CAMPAIGN)	6,664,281
27	AUX BLDG WATER MITIGATION BARRIER	4,842,077
28	ANC NFPA805 COMMON FEEDWATER	4,424,694
29	ANO DRY FUEL STORAGE (2016 CAMPAIGN)	3,713,600
30	ANO1 BMI PENETRATION MITIGATION	3,156,175
31	ANO-2 CEDM PURCHASE	3,017,080
32	U1 REPLACE PRESSURIZER HEATER BUNDL	2,954,779
33	ANC FLOOD BARRIER WATERPROOF UPGRAD	2,723,754
34	ANO1 SPARE RCP ROTATING ASSEMBLY	2,674,694
35	ANO2 INSTL OPEN PHSE DCTION XFM SU3	2,434,446
36	WB1 CAVR SCRUBBER,STACK,BURNERS	2,260,654
37	WB2 CAVR SCRUBBER,STACK,BURNERS	2,228,977
38	RD3 GENERATOR STATOR CORE & WINDING	2,228,573
39	ANO2 UNDERGROUND PIPING REPLACEMENT	1,873,630
40	ANO2 A600 SURFACE PEENING OF RVH PE	1,786,973
41	WBC ROTARY CAR DUMPER BARREL	1,418,452
42	AN1 NFPA805 COMMON FEEDWATER - INST	1,403,378
43	TOTAL	403,206,466

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	AN2NFPA805 COMMON FEEDWATERINSTALL	1,207,153
2	ANO2 EDG EXCITER/VOLTAGE REG REPL	1,200,286
3	ANO UNIT 1 NFPA805 1R26 WORK	1,183,500
4	SPO EAI UNION PROJECT (ARKANSAS)	1,092,499
5	ANO1 PURCHASE NE-501 DETECTOR	1,033,182
6	HT1 - MECHANICAL VACUUM SYSTEM	989,355
7	WB1 UNIT 1 ABSORBER AREA	931,265
8	ANO DFS (2014/2015 CAMPAIGN)	907,856
9	WB1 UNIT 1 BAGHOUSE	879,254
10	WB2 UNIT 2 BAGHOUSE	819,241
11	WBC REAGENT PREP SYSTEM	803,691
12	ANOC OPEN PHASE DETECTION (SU2)	756,293
13	WB2 UNIT 2 ABSORBER AREA	738,196
14	ANOC INSTALL PUMPS FOR MANHOLES	631,400
15	ANO1 OPEN PHASE DETECTION SU1	594,279
16	DECLARATORY ORDER FOR WB SCRUBBER	592,159
17	ANO1 UNDERGROUND PIPING REPLACEMENT	526,050
18	AN2 REPLACE 2L-16 CRANE	497,723
19	ANOC PURCHASE VOTES INFINITY SYSTEM	478,980
20	2P-7B U2 EFW NEW MOTOR PURCHASE	458,195
21	WB2 FLUE GAS SYSTEM	436,410
22	WB1 FLUE GAS SYSTEM	430,842
23	WBC DCS (FGD UNITS)	381,961
24	WBC ASH DISPOSAL CELL #4 LEACHATE	347,185
25	HT1 - IP TURBINE STAGE 11 ROTATING	324,669
26	WB1 BOOSTER FANS	316,933
27	WB2 BOOSTER FANS	316,933
28	ANO2 COOLING TOWER FILL REPLACEMENT	263,953
29	ANO1 REBUILD P-3B CIRC WTR PUMP	250,830
30	ANC PURCHASE WHOLE BODY COUNTER	242,983
31	ANO1 1R26 SW PIPING REPL	222,608
32	ANO2 RVLMS OBSOLETE EQUIP	218,212
33	ANO1 UPGRADE MAIN STEAM SAFETY VLV	203,159
34	HT1 - MOD1 CHILLER TOWER FILLMEDIA	201,691
35	WB2 FRONT PENDANT REHEATER ASSEMBLY	180,938
36	1R27 NFPA 805 WORK	175,831
37	ANO2 MAIN REFUELING BRIDGE UPGRADE	171,906
38	ANO1 1R26 FAC PIPING REPLACEMENT	163,807
39	CDC UNIT 3 BULKHEAD REPAIR AND PLUG	149,403
40	ANO2 2C-27 A/B AIR COMPRES REPLC	142,624
41	ANO2 EDG EXHAUST STACK REPLCMNT	134,955
42	ANO2-SEISMIC MODS-ESEP-BORIC ACIDTK	116,896
43	TOTAL	403,206,466

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	ANO2 2E-35B HEAT EXCH REFURBISHMENT	113,692
2	OTHER PRODUCTION PLANT	1,404,859
3		
4	TRANSMISSION & DISTRIBUTION SUBSTATION PLANT:	
5	DRIVER BUILD NEW 500/230KV SUB	50,654,073
6	WHITE BLUFF RECONFIGURE 500KV STA.	19,043,165
7	CIP V5 TRANSMISSION SUBS-EAI	10,982,306
8	WHITE BLUFF RECONF 230KV ADDITIONS	8,281,285
9	BUILD DRIVER SUBSTATION	8,268,455
10	WOODWARD RECONFIGURE 115KV BUS	7,707,112
11	COFER RD. - NEW SUBSTATION	6,269,028
12	MT PINE S-CONVERT TO 5 BREAKER RI	5,238,336
13	MACEDONIA: NEW SUBSTATION	4,465,305
14	GILLET ADD NEW LINE BAY	3,368,702
15	REED CONVERT TO A BREAKER STATION	2,177,902
16	MOOREFIELD: ADD XFMR	1,778,832
17	CIRCUIT REPL EAI TRANS SUBS 2015	1,616,236
18	EAI:PURCH SPARE 500-161KV AXFMR	1,572,878
19	WHITE BLUFF EHV; STORAGE YARD	1,352,519
20	ISES SPOF RELAY IMPROVEMENTS	1,224,537
21	STRONG SUB INSTALL T2	815,940
22	CIRCUIT REPL EAI TRANS SUBS 2016	812,685
23	BRINKLEY EAST; REPLACE 5 BREAKERS	737,774
24	SHERIDAN EHV; RPLC 500KV BKR B5018	733,756
25	EAI:PURCH SPARE 115-13.8KV XFMR	712,247
26	ANO; REPLACE 500KV BREAKER B5102	587,728
27	MONTICELLO EAST ADD BREAKER BAY	570,382
28	MABELVALE SPOF IMPROVEMENTS	558,298
29	BRINKLEY EAST; AUTO LIFE EXTENSION	553,857
30	ANO; REPLACE BREAKER B5122	472,112
31	EAI:PURCH SPARE 115-13.8KV XFMR	444,201
32	BRINKLEY EAST; PIN & CAP INSULATORS	413,905
33	HOT SPRINGS SPOF RELAY IMPROVEMENTS	349,015
34	BLDNEW PWRLINE RD 500/161KV GIS SUB	345,303
35	EAI:PURCH SPARE 13.8KV VOLT REG.	342,623
36	ARKLAHOMA; INSTALL VANQUISH FENCE	330,839
37	JACKSONVILLE N ADD FDR BKR	314,494
38	JACKSONVILLE S; T1 LIFE EXTENSION	300,666
39	EL DOR EHV; CODE SECURITY	293,570
40	LEWISVILLE; T1 LIFE EXTENSION	267,070
41	JACKSONVILLE S. RPLC CIRCUIT SWITCH	254,800
42	JEFFERSON INDUSTRIAL SS	249,999
43	TOTAL	403,206,466

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	L.R. INDUSTRIAL B0591 RPLC	214,939
2	L.R. ALEXANDER B0639 RPLC	214,921
3	JACKSONVILLE NORTH B3621 RPLC	190,249
4	NLR DIXIE; PIN & CAP INSULATORS	180,616
5	SHERIDAN SPOF RELAY IMPROVEMENTS	177,488
6	SEARCY PRICE B5310 RPLC	174,223
7	BRINKLEY EAST; RPLC 115KV CCVT'S	157,537
8	WOODWARD; CODE SECURITY	144,693
9	WOODWARD RELAY IMPROVEMENT SCOPING	139,311
10	NEWPORT IND; T3 LIFE EXTENSION	137,993
11	HS ALBRIGHT SUB: 115KV HIGH SIDE	134,143
12	SHERIDAN; T1 LIFE EXTENSION	131,306
13	P.B. 34TH MAIN BREAKER RPLC	128,253
14	PB DIERKS REMOTE END UPGRADES	116,800
15	ANO; CODE SUBSTATION SECURITY	115,847
16	BRINKLEY EAST, RPLC 115KV SWITCHES	115,223
17	LR MANN; T1 LIFE EXTENSION	111,682
18	CLINTON RELAYS FOR TRAINING	110,142
19	DELL EHV; CODE SUBSTATION SECURITY	108,634
20	EAI:PURCH SPARE 161-13.8KV XFMR	100,022
21	OTHER TRANSMISSION AND DISTRIBUTION SUB	4,562,097
22		
23	TRANSMISSION LINES PLANT:	
24	WOODWARD TO WHITE BLUFF 230KV- RT A	22,273,811
25	AECC HYDRO-GILLETT	9,098,950
26	MONTICELLO EAST/REED NEW 115KV LINE	4,754,070
27	CALICO ROCK TO NORFORK LINE UPGRADE	4,636,563
28	MCN LK-DERMOTT NEW 230KV	3,771,985
29	MCN LK-DERMOTT 115KV REBUILD	3,081,398
30	DRIVER-BIG RIVER NEW #1 230KV LINES	2,807,346
31	DRIVER-BIG RIVER NEW #2 230KV LINE	2,599,788
32	DERMOTT TO MCGEHEE 115KV REBUILD	2,275,787
33	DERMOTT TO MCGEHEE NEW 230KV	2,208,833
34	BRINKLEY - SEARCY PRICE, RPL X-ARMS	1,561,558
35	MOSES - PARKIN, RPL CROSSARMS	731,862
36	LV BAGBY - OAK GROVE, RPL ARMS	534,953
37	BLAKELY DAM_MT PINE S CUT IN	449,041
38	WDWRD - DGRY DAM, RPL STRUCTURES	423,848
39	BRNKLY E - W HLNA, RPL CROSSARMS	420,475
40	PB DIERKS - LYNCH, RPL STRUCTURES	401,591
41	MARKED TREE - PARKIN, RPL CROSSARMS	393,479
42	WDWRD - CRPNTR, RPL STRUCTURES	351,106
43	TOTAL	403,206,466

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	STEPHENS - MCNEIL, REPLACE STRS	326,483
2	DUMAS - LV BAGBY, RPL STRUCTURES	324,376
3	MINOR ADD TO WO# C6PPTLA161	314,199
4	JIM HILL-DATTO:CONVERT TO 161KV	269,532
5	ED EHV - WYATT, RPL STRUCTURES	231,521
6	MT PINE S_ROYAL CUT IN	213,780
7	WYNNE S - WYNNE IND, RPL X-ARMS	201,020
8	QUITMAN - GREERS FERRY, RPL STRS	186,841
9	MCALMONT B0980	177,419
10	HOLLAND BOTTOM-BEEBE 161KV LINE	166,815
11	MARION - MARKED TREE, RPL ARMS	163,514
12	MSES - NWPRT, INSTLL BIRD DIVERTERS	159,141
13	ISES - DELL, INSTALL BIRD GUARDS	158,924
14	CLARENDON - BRINKLEY, RPL CROSSARMS	135,427
15	GILLETTE TO ELAINE T-LINE	134,108
16	MCNEIL - COUCH, REPLACE STRUCTURES	132,001
17	MACEDONIA T-LINE CUT IN	127,692
18	CAMDEN MAGUIRE - MCNEIL, RPL STRS	122,000
19	ELD WEST - ELD MONSANTO, RPL STRS	118,711
20	LR WEST - LR GAINES, RPL STRS	102,198
21	OTHER TRANSMISSION LINES	2,021,915
22		
23	UNDISTRIBUTED OVERHEADS:	679,697
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	403,206,466

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	3,906,115,256	3,905,936,889	178,367	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	219,802,189	219,802,189		
4	(403.1) Depreciation Expense for Asset Retirement Costs	2,101,936	2,101,936		
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)	221,904,125	221,904,125		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	69,566,531	69,566,531		
13	Cost of Removal	46,884,011	46,880,441	3,570	
14	Salvage (Credit)	15,519,124	15,058,512	460,612	
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	100,931,418	101,388,460	-457,042	
16	Other Debit or Cr. Items (Describe, details in footnote):	-458,037	-995	-457,042	
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,026,629,926	4,026,451,559	178,367	

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

20	Steam Production	574,100,208	574,100,208		
21	Nuclear Production	1,471,106,649	1,471,106,649		
22	Hydraulic Production-Conventional	14,977,544	14,966,153	11,391	
23	Hydraulic Production-Pumped Storage				
24	Other Production	317,162,051	317,162,051		
25	Transmission	466,306,785	466,229,128	77,657	
26	Distribution	1,122,790,976	1,122,790,976		
27	Regional Transmission and Market Operation				
28	General	60,185,713	60,096,394	89,319	
29	TOTAL (Enter Total of lines 20 thru 28)	4,026,629,926	4,026,451,559	178,367	

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

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

Excludes service company depreciation allocations of \$8,387,020 (included in the depreciation expense shown on page 336), since these allocations do not offset to accumulated depreciation reserves.

Schedule Page: 219 Line No.: 12 Column: c

Excludes retirements of \$5,941,521 (included in Amortization of Other Utility Plant shown on pages 204 - 207), since these retirements do not offset to accumulated depreciation reserves.

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

Includes the following:

Net(Gain)/Loss closed to Accumulated Reserve	(\$13)
Reserve Transfers	(982)

Total	(\$995)
	=====

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

Net(Gain)/Loss closed to Accumulated Reserve.

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

Includes a debit balance of \$1,185,839 for asset retirement obligations.

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

Includes a credit balance of \$67,322,203 for asset retirement obligations.

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

Includes a debit balance of \$23,490 for asset retirement obligations.

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

Includes a credit balance of \$12,686 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 Arkklahoma Corporation			
2	Common Stock - 238 shares	5/16/47		64,872
3	Equity in Earnings - 47.6% Ownership			133,535
4	Subtotal			198,407
5				
6	System Fuels, Inc.			
7	Common Stock - 70 shares	1/4/72		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			-1,475,906
13	Subtotal			-855,306
14				
15	Arkansas Power & Light Company			
16	Capital Contribution			3,297,659
17	Undistributed retained earnings			-2,824,290
18	Subtotal			473,369
19				
20				
21				
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	-176,530

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 from investments, including such revenues from 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
		133,535		3
		198,407		4
				5
				6
		7,000		7
		7,000		8
				9
				10
		620,600		11
-357,201	-347	-1,833,454		12
-357,201	-347	-1,212,854		13
				14
				15
	2,436,128	5,733,787		16
-1,609,961		-4,434,251		17
-1,609,961	2,436,128	1,299,536		18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
-1,967,162	2,435,781	292,089		42

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)	48,344,089	56,824,236	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	2,359,731	5,807,518	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)	108,580,988	114,283,841	Electric
8	Transmission Plant (Estimated)	19,781,271	20,256,748	Electric
9	Distribution Plant (Estimated)	16,641,175	17,644,810	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)	145,003,434	152,185,399	
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)	17,788,971	17,733,783	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	213,496,225	232,550,936	

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		2016	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	84,372.00			
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	32,675.00		32,671.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Prior year adjustment	-140.00			
10					
11					
12					
13					
14					
15	Total	-140.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Allowances used	14,167.00			
23					
24					
25					
26					
27					
28	Total	14,167.00			
29	Balance-End of Year	102,740.00		32,671.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)	472.00	62		
34	Gains	472.00	62		
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA	472.00		472.00	
38	Deduct: Returned by EPA				
39	Cost of Sales	472.00		472.00	
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/transfersors 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.

2017		2018		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
						84,372.00		1
								2
								3
32,671.00		32,671.00		882,130.00		1,012,818.00		4
								5
								6
								7
								8
						-140.00		9
								10
								11
								12
								13
								14
						-140.00		15
								16
								17
								18
								19
								20
								21
						14,167.00		22
								23
								24
								25
								26
								27
						14,167.00		28
32,671.00		32,671.00		882,130.00		1,082,883.00		29
								30
								31
								32
						472.00		62 33
						472.00		62 34
								35
								36
472.00		472.00		12,744.00		14,632.00		37
								38
472.00		472.00		12,744.00		14,632.00		39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

Schedule Page: 228 Line No.: 4 Column: j

Future Years include allowances issued from 2019 through 2045.

Schedule Page: 228 Line No.: 37 Column: j

Amount reported for future years are for years 2019-2045.

Schedule Page: 228 Line No.: 39 Column: j

Amount reported for future years are for years 2019-2045.

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		2016	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	5,615.00	194,411		
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	4,351.00		4,329.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:	138.00	20,148		
9	Co-owner purchases billed	-3,053.00	-118,444		
10	Co-owner purchases unbilled	375.00	54,751		
11					
12					
13					
14					
15	Total	-2,540.00	-43,545		
16					
17	Relinquished During Year:				
18	Charges to Account 509	6,494.00	93,694		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	932.00	57,172	4,329.00	
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/transfersors 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.

2017		2018		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
						5,615.00	194,411	1
								2
								3
4,188.00		4,188.00		8,376.00		25,432.00		4
								5
								6
								7
						138.00	20,148	8
						-3,053.00	-118,444	9
						375.00	54,751	10
								11
								12
								13
								14
						-2,540.00	-43,545	15
								16
								17
						6,494.00	93,694	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
4,188.00		4,188.00		8,376.00		22,013.00	57,172	29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
FOOTNOTE DATA			

Schedule Page: 229 Line No.: 4 Column: j

Future years include allowances issued from 2019 through 2020.

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

Counterparty	No.	Amount
Houston-Galveston-Brazoria Energy Ventures, LLC	138	\$20,148

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21						
22						
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						
48						
49	TOTAL					

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	Transmission Studies				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	Generation Studies				
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Income Taxes	98,183,775		282,283	3,551,005	94,632,770
2						
3	Grand Gulf 1 Costs - Under Recovery	11,144,612		555	8,826,627	2,317,985
4						
5	TCA/Ice Storm Settlement - Docket No. 01-296-U					
6	and Docket No. 01-084-U, Amort 30 years	8,953,176		407.3	526,656	8,426,520
7						
8	System Agreement Costs Under Collection	108,591,480	1,566,780	557,431	89,652,895	20,505,365
9						
10	Asset Retirement Obligation - Nuclear	247,653,044	35,469,346	407.3	2,786,514	280,335,876
11						
12	Asset Retirement Obligation - Fossil	6,846,834	362,612			7,209,446
13						
14	Asset Retirement Obligation - Hydro	53,775	2,756			56,531
15						
16	Asset Retirement Obligation - Other	255,639	15,981			271,620
17						
18	Defined Benefit Pension and Other					
19	Postretirement Plans	838,161,099		(1)	71,679,858	766,481,241
20						
21	Deferred Storm Restoration Costs					
22	APSC Docket No. 09-031-U	57,735,408		(2)	15,011,624	42,723,784
23						
24	Federal Litigation Consulting Fees	1,269,270		928	405,672	863,598
25						
26	Deferred Fuel Under-Recovery	100,587,310	557,890	182.3,557	100,587,310	557,890
27						
28	MISO implementation costs Docket No.					
29	ER14-1645 and APSC Docket No.					
30	10-011-U Order No. 76. Amort thru Dec 2018	25,092,758		(3)	7,593,243	17,499,515
31						
32	Human Capital Management cost deferral					
33	APSC Docket No. 13-028-U, Order No. 21					
34	recover thru retail rates thru June 2017	17,315,327		(4)	6,926,131	10,389,196
35						
36	MOARK Agreement - APSC Docket No. 13-028-U					
37	Order No. 21. Amort period 20 year eff Jan 2014	8,232,475		566	433,288	7,799,187
38						
39	Capacity Costs Recovery Rider - Under Recovery	4,128,842		555	460,104	3,668,738
40						
41	Lake Catherine Reliability Costs Deferral					
42	APSC Docket No. 13-028-U Order No. 21	2,379,148	8,028,009			10,407,157
43						
44	TOTAL	1,545,599,821	122,455,454		314,998,374	1,353,056,901

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		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	MISO Financial Transmission Rights Mark-to-Market	1,009,827		242,254	1,009,827	
2						
3	MISO Rider - Under Recovery	2,458,402	9,643,947			12,102,349
4						
5	Asset Retirement Obligation - Coal		108,415			108,415
6						
7	Energy Efficiency Rider - Under Recovery 07-085-TF	5,547,620		254	5,547,620	
8						
9	Replacement Energy Fuel					
10	APSC Docket No. 13-028-U Order No. 23		66,699,718			66,699,718
11						
12						
13	(1) 190, 410.1, 411.1, 926, 107, 228.3					
14						
15	(2) 228.1, 593, 571, 407.3					
16						
17	(3) 407.3, 408.1, 560, 561.2, 561.1, 561.3, 561.5.					
18	566, 568, 569.1, 920, 921, 923, 924, 926, 928,					
19	930.1, 930.2, 935, 403.1, 925, 931, 562, 500,					
20	510, 556, 557, 905, 935					
21						
22	(4) 500, 506, 517, 524, 546, 560, 580, 907, 920,					
23	921, 923, 549, 566, 588, 931, 935, 408.1, 926					
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	1,545,599,821	122,455,454		314,998,374	1,353,056,901

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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Non-Expense Accrued Labor	3,109,017		232,236	2,080,747	1,028,270
2						
3	Section 263A	1,043,582		930.2	73,632	969,950
4						
5	Securitization Financing Costs					
6	Docket 10-008-U					
7	Amort pd 8/18/10-8/1/21	136,458		930.2	20,728	115,730
8						
9	Agric Irrig AMI Load Control					
10	Docket 08-072-TF	10,143,074	1,378,971	930.2	964,469	10,557,576
11						
12	Pooled Equipment - PEICo	1,735,475	59,274	517,232	103,191	1,691,558
13						
14	ANO Inventory Parts Purchase	296,041		143,154	247,623	48,418
15						
16	Other	65,102	18,877	Various	70,816	13,163
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						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	16,528,749				14,424,665

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 Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	See Footnote Detail	626,265,380	194,762,986
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	626,265,380	194,762,986
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)	626,265,380	194,762,986

Notes

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
FOOTNOTE DATA			

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

	BALANCE AT BEG OF YEAR	BALANCE AT END OF YEAR
Interest on Tax Deficiencies	\$73,352	\$73,352
ANO Shutdown Costs	(156,163)	(180,519)
Grand Gulf 1-Over/Under Recovery	(4,371,474)	(909,230)
Taxable Unbilled Revenue	12,322,362	9,815,027
Property Insurance	(22,646,714)	(16,758,405)
Capitalized Repairs	1,345,796	1,192,041
Injuries & Damages Reserve	1,742,555	1,586,029
Unfunded Pension	(94,189,247)	(107,990,316)
Minimum Pension Liability	317,165,050	289,484,957
Supplemental Pension	834,307	917,259
Other Retirement Benefits	(20,571,102)	(23,021,459)
Deferred Fuel Cost	(82,050,380)	(7,647,493)
Removal Cost	2,347,827	(9,757,092)
Litigation Settlement	166,706	-
Accrued Medical Claims	3,037,424	2,601,922
Uncollectible Accounts	6,794,383	7,570,813
Contract Deferred Revenue	657	657
Environmental Reserve	489,135	591,905
Incentive Compensation	332,465	887,486
ANO Bldg Sale/Leaseback Tax Gain	45,592	13,409
Long-Term Incentive Compensation	91,248	106,127
Stock Options	1,284,252	606,875
Restricted Stock Awards	375,366	241,742
Deferred Director's Compensation	318	264
Rate Refund	134,763	402,881
Miscellaneous Reserves	-	7,960,198
EPA Allowances	(12,278)	(33,489)
Severance Accrual	1,377	-
Accounts Payable Accrual	6,231,291	-
Income Tax Adjustment	33,969,996	33,194,672
Net Operating Loss Carryforward	459,896,125	2,376,850
Contribution Carryforward	63,426	
Tax Credit Carryforward	1,316,965	1,236,523
FIN 48 Adjustment	200,000	200,000
	-----	-----
TOTAL	\$626,265,380	\$194,762,986
	=====	=====

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		
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/Q4

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.
Shares (e)	Amount (f)	AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
		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
						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
						42

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/Q4

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		
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	TOTAL	586,782,648

Name of Respondent Entergy Arkansas, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of <u>2015/Q4</u>
--	---	---------------------------------------	--

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	49,710
2	Capital Stock Expense - Preferred Stock	1,753,123
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	1,802,833

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	6.38% Series	60,000,000	609,720
5			59,400 D
6	5.66% Series	175,000,000	1,725,102
7			47,250 D
8	5.75% Series	225,000,000	7,400,537
9			
10	3.75% Series	350,000,000	2,518,954
11			101,500 D
12	4.9% Series	200,000,000	6,777,506
13			
14	3.05% Series	250,000,000	1,989,735
15			705,000 D
16	4.75% Series	125,000,000	4,151,566
17			
18	3.70% Series	375,000,000	3,081,212
19			270,000 D
20	4.95% Series	250,000,000	2,430,691
21			1,780,000 D
22			
23	TOTAL ACCOUNT 221	2,110,000,000	35,009,033
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	2,209,700,000	36,011,691

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 224 - OTHER LONG-TERM DEBT:		
2	POLLUTION CONTROL BONDS:		
3	Independence County 2.375% Series 2013	45,000,000	508,717
4			
5	Jefferson County 1.55% Series 2013	54,700,000	493,941
6			
7	SOLID WASTE DISPOSAL BONDS:		
8	Department of Energy (Nuclear Fuel Disposal Cost)		
9			
10	LONG-TERM OBLIGATIONS:		
11	Little Rock Air Force Base distribution facilities 4.2%		
12			
13	TOTAL ACCOUNT 224	99,700,000	1,002,658
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	2,209,700,000	36,011,691

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		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
06/11/2003	06/01/2033	06/11/2003	06/01/2033	100,000,000	5,900,000	2
						3
10/12/2004	11/01/2034	10/12/2004	11/01/2034	60,000,000	3,828,000	4
						5
01/19/2005	02/01/2025	01/19/2005	02/01/2025	175,000,000	9,905,000	6
						7
10/08/2010	11/01/2040	10/08/2010	11/01/2040	225,000,000	12,937,500	8
						9
11/12/2010	02/15/2021	11/12/2010	02/15/2021	350,000,000	13,125,000	10
						11
12/13/2012	12/01/2052	12/13/2012	12/01/2052	200,000,000	9,800,000	12
						13
05/30/2013	06/01/2023	05/30/2013	06/01/2023	250,000,000	7,625,000	14
						15
06/04/2013	06/01/2063	06/04/2013	06/01/2063	125,000,000	5,937,500	16
						17
03/14/2014	06/01/2024	03/14/2014	06/01/2024	375,000,000	13,875,000	18
						19
12/09/2014	12/15/2044	12/09/2014	12/15/2044	250,000,000	12,375,000	20
						21
						22
				2,110,000,000	95,308,000	23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				2,393,150,901	97,360,507	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		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
						2
01/09/2013	01/01/2021	01/09/2013	01/01/2021	45,000,000	1,068,750	3
						4
01/09/2013	10/01/2017	01/09/2013	10/01/2017	54,700,000	847,850	5
						6
						7
				181,377,972	48,510	8
						9
						10
				2,072,929	87,397	11
						12
				283,150,901	2,052,507	13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				2,393,150,901	97,360,507	33

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

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.

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 filed, 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)	74,271,622
2		
3		
4	Taxable Income Not Reported on Books	
5	See Footnote Detail	8,335,632
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	See Footnote Detail	89,730,008
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	See Footnote Detail	18,667,884
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See Footnote Detail	185,604,049
21		
22		
23	Other Reconciling Items	
24	See Footnote Detail	11,951,024
25		
26		
27	Federal Tax Net Income	-19,983,647
28	Show Computation of Tax:	
29		
30	Normal & Surtax (\$19,983,647) @ 35%	-6,994,276
31		
32	Estimated Consolidated Income Tax	
33	See Footnote Detail	
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
FOOTNOTE DATA			

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

Taxable Income Not Reported on Books:	
Taxable Unbilled Revenue	(\$6,237,156)
Contributions in Aid of Construction	3,927,143
TCBY Tower	659,194
Interest Capitalized	9,986,451

Total	\$8,335,632 =====

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

Deductions Recorded on Books Not Deducted for Return:	
Nuclear Fuel Expense	\$102,844,653
Securitization	(1,003,158)
Property Insurance Reserve	15,011,624
Increase in Reserves	(12,037,616)
Deferred Nuclear Shutdown Costs	(62,092)
Reserve for Uncollectible Accounts	1,979,426
Non-deductible Meals & Entertainment	227,452
TCA/Ice Storm Settlement	526,656
Amortization of Bond Reacquisition Losses	3,190,072
Maintenance Refueling Reserve	(38,144,166)
Long Term Incentive Plan	42,795
Deferral of Grand Gulf Cost per Settlement	8,826,627
Non-deductible Penalties	16,655
Non-deductible PAC & Political Expenses	1,210,081
Pension Expense	(26,696,216)
Restricted Stock	(138,651)
Research & Experimentation	2,142,371
Option Grant	190,036
Rate Refund	684,047
Accounts Payable	4,407,665
Reversal of AFUDC equity & net-of-tax	9,459,177
Depreciation-Reverse prior flow-through	15,331,371
Deferred Director's Fees	(138)
Litigation Accrual	(425,000)
Severance Accrual	(3,510)
Decommissioning - Dry Cask	2,149,847

Total	\$89,730,008 =====

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

Income Recorded on Books Not Included in Return:	
Amortization of Gain on Sale of Property	\$82,048
Equity in Domestic Subs	(1,609,989)
Allowance for Funds Used During Construction	20,195,825

Total	\$18,667,884 =====

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2015/Q4
FOOTNOTE DATA			

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

Deductions on Return Not Charged Against Book Income:	
Excess of Tax over Book Depreciation	\$86,677,694
Property Book/Tax Diff-PowerTax	204,950,762
Daily Lease Charges	1,512,703
Interest Pymts on UTP's	19,379,372
Early Retiree Reimbursement	59,000
Vegetation Management	738,409
Deferred Fuel Expense	(122,982,597)
Regulatory Capitalized Costs	11,644,080
Mark to Market-Other Contracts	3,281,000
Coal Car Lease Payments	(2,103,065)
System Agreement - Supplier Refund	1,566,780
Prepaid Expenses	(1,214,152)
Warranty Expense	84,483
Units of Property Deduction/Tangible Prop	1,303,353
Reg Asset - Gustav & Ike	(13,427,202)
Tax Gain/Loss Prop Items	62
EPA Allowances	(62)
License Extension Costs	243,267
MISO Cost Deferral	(7,593,243)
MOARK Cost Deferral	(433,288)
HCM Cost Deferral	(6,926,131)
Business Development Costs	1,563,709
Depletion	28,830
ESI Taxes	1,201,995
Rev Proc 2000-50 SW Costs	5,218,755
Incentive Compensation	128,025
Reversal of Book Reserve	524,982
Deductions for Dividends Paid on Certain Preferred Stock	176,528

Total	\$185,604,049
	=====

Schedule Page: 261 Line No.: 24 Column: b

Reconciling Items for the Year:	
Federal Income Tax Accrual - Current Year	(\$6,994,276)
Federal Income Tax - FIN 48	3,958,298
Federal Income Tax Accrual - Prior Year	54,556,517
State Income Tax Accrual - Prior Year	6,232,914
Provision for Deferred Income Tax - Federal	(21,205,270)
Provision for Deferred Income Tax - State	2,547,129
Provision for Investment Tax Credit	(1,201,283)
NOL Origination/Utilization	(27,145,000)
ESI Taxes	1,201,995

Total	\$11,951,024
	=====

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
FOOTNOTE DATA			

Schedule Page: 261 Line No.: 33 Column: b

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 2015. 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.	(\$6,946,000)
Entergy Gulf States Louisiana, L.L.C.	130,659,000
Entergy Louisiana Holdings, Inc	(7,371,000)
Entergy Mississippi, Inc.	26,673,000
Entergy New Orleans, Inc.	9,018,000
System Energy Resources, Inc.	(235,477,000)
Entergy Services, Inc.	11,553,000
System Fuels, Inc.	379,000
Entergy Operations, Inc.	(439,000)
Entergy Corporation	(249,915,000)
Entergy Solutions LLC	(4,000)
Entergy Nuclear Generation Company	(83,108,000)
Entergy Nuclear New York Investment Company I	45,657,000
Entergy Nuclear Holding Company #3, LLC	47,785,000
Entergy Nuclear Vermont Investment Company, LLC	(55,555,000)
Entergy Power Marketing Holding II, Inc	13,169,000
Entergy Nuclear, Inc.	(1,855,000)
Entergy Nuclear Holding Company #1	(11,000)
TLG Services, Inc.	178,000
Entergy Nuclear Operations, Inc	(10,986,000)
Entergy Nuclear PFS Co.	(3,000)
Entergy Nuclear Fuels Company	(29,000)
Entergy Power Holdings, Inc	4,705,000
Entergy Nighthawk GP, LLC	65,779,000
Entergy Power International Holdings	18,861,000
Entergy Mississippi Turbine Company	(702,000)
Entergy Nuclear Holding Company #2	1,671,000
EP LLC	(1,667,000)
Entergy Enterprises, Inc.	(1,057,000)
Entergy Power Gas Operations LLC	16,814,000
Entergy Power Marketing Holding I, Inc.	41,579,000
GSG&T, Inc	1,373,000
Entergy Power Operations U.S., Inc.	449,000
Entergy Nuclear Palisades, Inc	(37,873,000)
EK Holding III, LLC	(17,000)
EGS Holdings LLC	(291,000)
Entergy Texas, Inc	55,140,000
Entergy Holdings Company LLC	95,273,000
Entergy Global LLC	4,967,000
Entergy Louisiana, LLC	101,888,000
Entergy Louisiana Properties LLC	(2,000)
Arkansas Power & Light Company LLC	285,000
Entergy Nuclear Vermont Finane Co.	20,000
Entergy Technologies Company	(774,000)
Warren Power, LLC	(2,768,000)
Entergy Asset Management, Inc.	3,446,000
Entergy Investment Holding Company	(40,000)
EWO Wind II, LLC	(431,000)
Total	----- \$- =====

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 known, 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 Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	FEDERAL TAXES:					
2	Federal Income Tax	-29,644,113		47,841,167	85,266,000	
3	FICA	402,606		10,589,169	9,268,982	
4	Federal Unemployment Tax	-795,624		63,340	55,898	
5	Federal Excise Tax			8,236	8,236	
6	Subtotal	-30,037,131		58,501,912	94,599,116	
7						
8	STATE & LOCAL TAXES:					
9	State Income Tax	-21,808,689		6,067,974	-1,094,203	
10	State Unemployment Tax	449,408		236,488	209,295	
11	Capital Stock Franchise			588,183	588,183	
12	Regulatory Commission		1,648,352	3,241,898	3,186,992	
13	Use Tax	3,991,126		21,148,947	22,757,541	
14	Gross Receipts & Sales Tax	1,500		59,117	56,953	
15	Railcar	31,353		88,943	90,358	
16	Gross Receipts Privilege Tax			10	10	
17	Ad Valorem Tax	37,953,000		40,648,070	38,566,132	
18	Franchise Tax - Local	5,898,864		42,960,040	40,775,911	
19	State Excise Tax			34,847	34,847	
20	Non Income Tax	187,000				
21	Subtotal	26,703,562	1,648,352	115,074,517	105,172,019	
22						
23	Payroll Loading Tax					
24						
25	Taxes Other Than					
26	Income Taxes					
27	Entergy Services, Inc.					
28						
29						
30	Income Taxes					
31	Entergy Services, Inc.					
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	-3,333,569	1,648,352	173,576,429	199,771,135	

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 (l) 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
-67,068,946		39,211,036			8,630,131	2
1,722,793		4,636,038			5,953,131	3
-788,182		31,126			32,214	4
		8,236				5
-66,134,335		43,886,436			14,615,476	6
						7
						8
-14,646,512		4,316,327			1,751,647	9
476,601		113,903			122,585	10
		588,183				11
	1,593,446	3,241,898				12
2,382,532					21,148,947	13
3,664		59,117				14
29,938					88,943	15
		10				16
40,034,938		35,285,607			5,362,463	17
8,082,993		43,066,189			-106,149	18
		34,847				19
187,000						20
36,551,154	1,593,446	86,706,081			28,368,436	21
						22
		1,554			-1,554	23
						24
						25
						26
		12,695,467			-12,695,467	27
						28
						29
						30
		-370,262			370,262	31
						32
						33
						34
						35
						36
						37
						38
						39
						40
-29,583,181	1,593,446	142,919,276			30,657,153	41

Name of Respondent
 Entergy Arkansas, Inc.

This Report Is:
 (1) An Original
 (2) A Resubmission

Date of Report
 (Mo, Da, Yr)
 / /

Year/Period of Report
 End of 2015/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%	56,219			411.4	17,737	
4	7%						
5	10%	37,651,443			411.4	1,183,546	
6							
7							
8	TOTAL	37,707,662				1,201,283	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
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
38,482	60yr		3
			4
36,467,897	60yr		5
			6
			7
36,506,379			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

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

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

OTHER DEFERRED 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		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Unfunded Pension Expense	508,196,690	131	92,419,061	25,115,232	440,892,861
2						
3	Supplemental Pension Plan	4,147,957	(1)	1,758,194	176,250	2,566,013
4						
5	Book Gain on Sale/Leaseback					
6	ANO Support Buildings - Amort					
7	Period 30 years/term of lease	116,233	525	82,048		34,185
8						
9	Long-term Incentive Plan	232,626	131	100,665	138,598	270,559
10						
11	Unrecoverable costs - EAI Rate					
12	Case Settlement - Docket 09-84-U	28,313,437	107,426.5	649,045	6,711,386	34,375,778
13						
14	KGEN Asset					
15	Purchase Agreement	12,200,000	242	12,200,000		
16						
17	Non IPP Advances	5,071,943	(2)	4,743,039		328,904
18						
19	Employment Litigation Liability	425,000	(3)	425,000		
20						
21	Ouachita gas yard	1,997,447	501	595,745	91	1,401,793
22						
23	Union Power Partners					
24	collateral payment	6,000,000				6,000,000
25						
26	Allowed Return on Equity					
27	for MSS-4 sales	524,982	229	524,982		
28						
29	(1) 242, 241, 232					
30						
31	(2) 107, 143, 174					
32						
33	(3) 228.2, 426.5, 920, 232					
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	567,226,315		113,497,779	32,141,557	485,870,093

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amortizable property.
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)	Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21

NOTES (Continued)

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)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	1,678,095,477	461,003,575	413,924,492
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	1,678,095,477	461,003,575	413,924,492
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	1,678,095,477	461,003,575	413,924,492
10	Classification of TOTAL			
11	Federal Income Tax	1,447,346,505	398,532,187	353,077,674
12	State Income Tax	230,748,972	62,471,388	60,846,818
13	Local Income Tax			

NOTES

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
		182.3	2,158,123			1,723,016,437	2
							3
							4
			2,158,123			1,723,016,437	5
							6
							7
							8
			2,158,123			1,723,016,437	9
							10
		182.3	1,779,072			1,491,021,946	11
		182.3	379,051			231,994,491	12
							13

NOTES (Continued)

ACCUMULATED DEFERRED 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)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	See Footnote Detail	950,503,548	82,130,671	552,086,251
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	950,503,548	82,130,671	552,086,251
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)	950,503,548	82,130,671	552,086,251
20	Classification of TOTAL			
21	Federal Income Tax	867,811,834	68,296,988	535,562,576
22	State Income Tax	82,691,714	13,833,683	16,523,675
23	Local Income Tax			

NOTES

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				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
		Footnote	29,073,258	123.1	2,230,233	453,704,943	3
							4
							5
							6
							7
							8
			29,073,258		2,230,233	453,704,943	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
			29,073,258		2,230,233	453,704,943	19
							20
		Footnote	24,255,274	123.1	2,230,233	378,521,205	21
		Footnote	4,817,984			75,183,738	22
							23

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2015/Q4
FOOTNOTE DATA			

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

	BALANCE AT BEGINNING OF YEAR	CHANGES DURING YEAR			
		AMOUNTS DEBITED TO ACCT. 410.1	AMOUNTS CREDITED TO ACCT. 411.1	AMOUNTS DEBITED TO ACCT. 410.2	AMOUNTS CREDITED TO ACCT. 411.2
Reg Asset-Securitization	\$32,815,656	\$16,271,152	\$17,102,381	\$-	\$-
Reg Asset-MISO	9,842,635	172,746	3,151,196	-	-
Replace Energy Fuel	-	27,680,383	1,517,419	-	-
System Equalization Agrmt	-	650,214	35,645	-	-
Maint/Refueling Reserve	11,646,000	26,844,402	11,882,353	-	-
Minimum Pension Liability	317,165,051	-	-	-	-
Bond Reacquisition Loss	10,262,274	72,574	1,323,879	-	-
Section 475 Adj	17,072,826	2,352,264	18,145,818	-	-
Capitalized Costs	8,037,121	57,082	851,938	-	-
Reg Asset-HCM	6,791,937	157,569	2,874,344	-	-
Reg Asset-MOARK	3,229,188	9,857	179,814	-	-
TCBY Tower (CADC)	4,733,080	1,126,004	8,089,035	-	-
Misc Cap Costs	4,688,905	676,423	705,338	-	-
Reg Asset-30yr Retail	3,511,881	11,981	218,560	-	-
Prepaid Expenses	2,323,064	3,867,846	3,957,012	-	-
263A Method Change-283901	143,961,406	654,052	144,615,458	-	-
263A Method Change-283F48	335,909,939	1,526,122	337,436,061	-	-
Income tax Adj	38,512,585	-	-	-	-
	<u>\$950,503,548</u>	<u>\$82,130,671</u>	<u>\$552,086,251</u>	<u>\$-</u>	<u>\$-</u>
	=====	=====	=====	=====	=====

	ADJUSTMENTS				BALANCE AT END OF YEAR
	ACCOUNT CREDITED	DEBITS AMOUNT	ACCOUNT DEBITED	CREDITS AMOUNT	
Reg Asset-Securitization		\$-		\$-	\$31,984,427
Reg Asset-MISO		-		-	6,864,185
Replace Energy Fuel		-		-	26,162,964
System Equalization Agrmt		-		-	614,569
Maint/Refueling Reserve		-		-	26,608,049
Minimum Pension Liability	190	27,680,094		-	289,484,957
Bond Reacquisition Loss		-		-	9,010,969
Section 475 Adj		-		-	1,279,272
Capitalized Costs		-		-	7,242,265
Reg Asset-HCM		-		-	4,075,162
Reg Asset-MOARK		-		-	3,059,231
TCBY Tower (CADC)	123.1	282	123.1	2,230,233	-
Misc Cap Costs		-		-	4,659,990
Reg Asset-30yr Retail		-		-	3,305,302
Prepaid Expenses		-		-	2,233,898
263A Method Change-283901		-		-	-
263A Method Change-283F48		-		-	-
Income tax Adj	182.3	1,392,882		-	37,119,703
		<u>\$29,073,258</u>		<u>\$2,230,233</u>	<u>\$453,704,943</u>
		=====		=====	=====

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 (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Certain Investments in Debt & Equity Securities:					
2	ANO 1 Qualified Fund - Valuation Acct	137,166,283	128	45,307,624	38,587,434	130,446,093
3	ANO 2 Qualified Fund - Valuation Acct	116,869,777	128	40,994,011	29,812,321	105,688,087
4						
5	Income Taxes	33,969,996	190	775,324		33,194,672
6						
7	Energy Efficiency Rider - Over Recovery					
8	07-085-TF		182.3	5,547,620	7,294,846	1,747,226
9						
10	MISO Transmission Financial Rights Mark to Market		175;182.3	2,195,400	7,226,552	5,031,152
11						
12	Deferred Fuel Under Recovery		182.3	7,065,121	36,980,921	29,915,800
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	288,006,056		101,885,100	119,902,074	306,023,030

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	816,388,100	746,943,385
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	510,880,158	457,018,130
5	Large (or Ind.) (See Instr. 4)	473,819,660	420,727,723
6	(444) Public Street and Highway Lighting	9,485,063	8,987,414
7	(445) Other Sales to Public Authorities	10,231,655	9,219,761
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,820,804,636	1,642,896,413
11	(447) Sales for Resale	323,571,357	412,805,009
12	TOTAL Sales of Electricity	2,144,375,993	2,055,701,422
13	(Less) (449.1) Provision for Rate Refunds	159,064	-1,395,135
14	TOTAL Revenues Net of Prov. for Refunds	2,144,216,929	2,057,096,557
15	Other Operating Revenues		
16	(450) Forfeited Discounts	10,298,231	9,913,700
17	(451) Miscellaneous Service Revenues	3,072,217	3,078,538
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	5,728,923	6,022,607
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-4,208,958	1,604,777
22	(456.1) Revenues from Transmission of Electricity of Others	71,432,167	70,172,693
23	(457.1) Regional Control Service Revenues	7,907,693	9,427,571
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	94,230,273	100,219,886
27	TOTAL Electric Operating Revenues	2,238,447,202	2,157,316,443

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
8,016,308	8,069,921	588,067	586,023	2
				3
6,019,807	5,933,527	91,614	90,730	4
6,888,953	6,808,335	23,797	23,648	5
77,849	77,408	635	635	6
157,311	160,115	65	56	7
				8
				9
21,160,228	21,049,306	704,178	701,092	10
10,219,229	10,301,475	3	3	11
31,379,457	31,350,781	704,181	701,095	12
				13
31,379,457	31,350,781	704,181	701,095	14

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

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
FOOTNOTE DATA			

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 Revenues includes:

Unbilled Revenue*	(\$7,121,543)
MISO Mkt Sch 11 Wholesale Distribution Revenue	1,934,010
AR Gross Receipts Tax	720,219
Affiliate Service Fee Revenue	245,000
Little Rock Air Force Base	191,656
Third Party Sales of Inventory	18,023
Misc Rec - Ouachita Upgrades	(197,062)
Commission to Entergy Arkansas from Co-owners to MISO	739
Total	----- (\$4,208,958) =====

*Includes (118,984) MWH

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

Other Electric Revenue includes:

MISO Mkt Sch 11 Wholesale Distribution Revenue	\$2,503,647
AR Gross Receipts Tax	641,932
Affiliate Service Fee Revenue	245,000
Misc Rec - Ouachita upgrades	197,062
Third Party Sales of Inventory	40,736
Unbilled Revenues*	(1,594,063)
Little Rock Air Force Base	(334,545)
Commission to Entergy Arkansas from Co-owners to MISO	(94,829)
Distribution Substation Svc.	(163)
Total	----- \$1,604,777 =====

*Includes (98,553) MWH

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 Sch 1 System Control & Dispatch	233,771	473,495	763,697	995,332
2	MISO Sch 2 Reactive	633,881	1,936,941	3,601,262	4,740,961
3	AECC MISO Sch 1	249,899	434,374	703,246	894,393
4	AECC MISO Sch 2	181,644	492,293	935,165	1,277,007
5					
6					
7					
8					
9					
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					
41					
42					
43					
44					
45					
46	TOTAL	1,299,195	3,337,103	6,003,370	7,907,693

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.	7,926,606	498,190,175	585,018	13,549	0.0629
3	RS3 Gen. Purpose Res.	7,634	488,650	421	18,133	0.0640
4	RT Opt. Res. Time-of-Use	692	44,412	52	13,308	0.0642
5	RMT Res Energy Mgmt TOU	356	22,448	24	14,833	0.0631
6	L4 All Night Outdoor Lighting	80,828	8,475,206	2,528	31,973	0.1049
7	M26 Rate Rider		1			
8	M33 Rate Rider		68,211,891			
9	ECR Energy Cost Recovery Rider		142,629,059			
10	PCA Production Costs Allocation R		33,931,939			
11	EECR Energy Efficiency Cost Rate		44,373,707			
12	CA Capacity Acquisition Rider		-111			
13	MFA Municipal Franchise Adj		21,567,036			
14	GMES Gov't Mandated Exp Srchg		-1			
15	FLCF Federal Litig Consult Fee		453,544			
16	ANOR ANO1 Interim Capacity Cost		236			
17	CCR Capacity Cost Recovery Rider		8,061,204			
18	MISO		-10,078,142			
19	IBRA Interim Base Rate Adjustment		1,952			
20	Misc	192	14,894	24	8,000	0.0776
21	TOTAL RESIDENTIAL	8,016,308	816,388,100	588,067	13,632	0.1018
22						
23	COMMERCIAL					
24	SG1 Small Gen. Service	3,204,834	182,854,328	84,467	37,942	0.0571
25	SG2 Small Gen. Service	16,583	873,734	23	721,000	0.0527
26	SG3 Small Gen. Service	671	33,352	6	111,833	0.0497
27	SG4 Small Gen. Service	8,856	459,200	30	295,200	0.0519
28	SG6 Small Gen Service	62	3,016	1	62,000	0.0486
29	SG7 Small Gen. Service	12,714	714,778	746	17,043	0.0562
30	GT1 Opt. LGS Time-of-Use	698,202	25,548,015	359	1,944,852	0.0366
31	GT2 Opt. LGS Time-of-Use	42,445	1,486,133	6	7,074,167	0.0350
32	GT4 Opt. LGS Time-of-Use	36,107	1,191,698	9	4,011,889	0.0330
33	IG1 LGS TOU Interruptible	7,236	139,596	2	3,618,000	0.0193
34	IG4 LGS TOU Interruptible	196,946	3,079,880	3	65,648,667	0.0156
35	LG1 Large Gen. Service	1,049,929	45,381,822	1,004	1,045,746	0.0432
36	LG2 Large Gen. Service	28,979	1,187,698	11	2,634,455	0.0410
37	LG4 Large Gen. Service	21,420	899,817	12	1,785,000	0.0420
38	IL1 LGS Interruptible	18,198	430,755	5	3,639,600	0.0237
39	IL4 LGS Interruptible	23,719	504,002	1	23,719,000	0.0212
40	LP1 Large Power Service	28,325	1,136,909	4	7,081,250	0.0401
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	LP2 Large Power Service	9,927	463,327	2	4,963,500	0.0467
2	LP4 Large Power Service	56,209	2,073,235	4	14,052,250	0.0369
3	PT1 Opt. LPS Time-of-Use	83,330	2,740,254	8	10,416,250	0.0329
4	PT2 Opt. LPS Time-of-Use	139,620	4,734,155	8	17,452,500	0.0339
5	PT4 Opt. LPS Time-of-Use	186,197	6,274,067	7	26,599,571	0.0337
6	IT4 LPS Time-of-Use Interruptib	14,815	248,124	1	14,815,000	0.0167
7	CTV Comm. Ant. & TV Amp.	25,909	1,585,361	2,671	9,700	0.0612
8	L4 All Night Outdoor Lighting	106,552	8,193,231	2,171	49,080	0.0769
9	M33 Rate Rider		37,469,743			
10	ECR Energy Cost Recovery Rider		108,328,637			
11	PCA Production Costs Allocation R		25,629,725			
12	EECR Energy Efficiency Cost Rate		28,291,926			
13	CA Capacity Acquisition Rider		-2,164			
14	MFA Municipal Franchise Adj		19,002,695			
15	GMES Gov't Mandated Exp Srchg		-195			
16	FLCF Federal Litig Consult Fee		346,463			
17	ANO ANO1 Interim Capacity Cost Re		810			
18	CCR Capacity Cost Recovery Rider		5,727,253			
19	MISO		-6,273,902			
20	IBRA Interim Base Rate Adjustment		13,651			
21	Misc	2,022	109,029	53	38,151	0.0539
22	TOTAL COMMERCIAL	6,019,807	510,880,158	91,614	65,708	0.0849
23						
24	INDUSTRIAL					
25	FA General Farm Service	84,643	4,410,590	4,127	20,510	0.0521
26	FAC General Farm Service	71,999	4,923,174	1,323	54,421	0.0684
27	SG1 Small Gen. Service	648,034	38,611,247	10,108	64,111	0.0596
28	SG2 Small Gen. Service	58,052	3,287,996	52	1,116,385	0.0566
29	SG3 Small Gen. Service	4,133	195,721	25	165,320	0.0474
30	SG4 Small Gen. Service	73,262	3,383,401	42	1,744,333	0.0462
31	SG5 Small Gen. Service	34,249	3,257,934	4	8,562,250	0.0951
32	SG6 Small Gen. Service	1,684	205,330	1	1,684,000	0.1219
33	IS2 SGS Interruptible	624	25,506	1	624,000	0.0409
34	IS4 SGS Interruptible	26,888	1,208,929	2	13,444,000	0.0450
35	GT1 Opt. LGS Time-of-Use	287,493	10,242,721	111	2,590,027	0.0356
36	GT2 Opt. LGS Time-of-Use	29,991	1,196,319	7	4,284,429	0.0399
37	GT4 Opt. LGS Time-of-Use	190,544	5,742,751	53	3,595,170	0.0301
38	IG1 LGS TOU Interruptible	49,513	974,027	5	9,902,600	0.0197
39	IG3 LGS TOU Interruptible	5,492	100,262	1	5,492,000	0.0183
40	IG4 LGS TOU Interruptible	87,937	1,512,523	3	29,312,333	0.0172
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	LG1 Large Gen. Service	465,827	20,982,179	269	1,731,699	0.0450
2	LG2 Large Gen. Service	36,109	1,819,637	17	2,124,059	0.0504
3	LG3 Large Gen. Service	750	33,681	1	750,000	0.0449
4	LG4 Large Gen. Service	60,766	3,676,409	17	3,574,471	0.0605
5	LG5 Large Gen. Service	3,735	252,089	4	933,750	0.0675
6	IL1 LGS Interruptible	25,189	613,759	9	2,798,778	0.0244
7	IL2 LGS Interruptible	24,539	689,324	2	12,269,500	0.0281
8	LP1 Large Power Service	30,212	1,434,034	5	6,042,400	0.0475
9	LP2 Large Power Service	200,774	8,441,602	13	15,444,154	0.0420
10	LP4 Large Power Service	275,183	11,062,451	18	15,287,944	0.0402
11	IP2 LPS Interruptible	25,976	847,331	1	25,976,000	0.0326
12	PT1 Opt. LPS Time-of-Use	204,193	7,349,631	18	11,344,056	0.0360
13	PT2 Opt. LPS Time-of-Use	441,871	16,268,410	19	23,256,368	0.0368
14	PT4 Opt. LPS Time-of-Use	1,909,014	58,737,770	50	38,180,280	0.0308
15	PT5 Opt. LPS Time-of-Use	42,986	2,040,436	5	8,597,200	0.0475
16	PT6 Opt. LPS Time-of-Use	33,795	1,206,108	2	16,897,500	0.0357
17	IT1 LPS TOU Interruptible	17,302	435,247	2	8,651,000	0.0252
18	IT4 LPS TOU Interruptible	711,388	18,930,880	4	177,847,000	0.0266
19	IT6 LPS TOU Interruptible	330,966	6,262,576	2	165,483,000	0.0189
20	APA Irrigation Service	228,119	14,977,761	5,593	40,787	0.0657
21	APB Irrigation Service	38,643	3,216,296	1,592	24,273	0.0832
22	CGS Cotton Ginning Service	17,050	1,085,253	36	473,611	0.0637
23	L4 All Night Outdoor Lighting	15,337	1,139,999	248	61,843	0.0743
24	SS Standby Service	94,691	4,378,990			0.0462
25	C23 Cogeneration		991	5		
26	M26 Rate Rider		1			
27	M33 Rate Rider		32,811,844			
28	ECR Energy Cost Recovery Rider		123,177,077			
29	PCA Production Costs Allocation R		29,102,229			
30	EECR Energy Efficiency Cost Rate		21,205,968			
31	CA Capacity Acquisition Rider		13,973			
32	SDR Storm Damage Rider		-21			
33	MFA Municipal Franchise Adj		2,469,627			
34	GMES Gov't Mandated Exp Srchg		-2,178			
35	FLCF Federal Litig Consult Fee		393,854			
36	ANOR ANO1 Interim Capacity Cost		2,017			
37	CCR Capacity Cost Recovery Rider		5,810,771			
38	MISO		-6,341,613			
39	IBRA Interim Base Rate Adjustment		14,836			
40	TOTAL INDUSTRIAL	6,888,953	473,819,660	23,797	289,488	0.0688
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	71,441	6,161,051	308	231,951	0.0862
3	L1SH Municipal Shielded Street Li	98	12,241	2	49,000	0.1249
4	L2 Traffic Signal Service	5,977	390,292	263	22,726	0.0653
5	L4 All Night Outdoor Lighting	333	28,266	62	5,371	0.0849
6	M33 Rate Rider		861,474			
7	ECR Energy Cost Recovery Rider		1,397,163			
8	PCA Production Costs Allocation R		318,319			
9	EECR Energy Efficiency Cost Rate		247,061			
10	CA Capacity Acquisition Rider		-117			
11	MFA Municipal Franchise Adj		23,222			
12	FLCF Federal Litig Consult Fee		4,467			
13	ANOR ANO1 Interim Capacity Cost		56			
14	CCR Capacity Cost Recovery Rider		49,437			
15	MISO		-7,953			
16	IBRA		84			
17	TOTAL PUBLIC STREET & HWY	77,849	9,485,063	635	122,597	0.1218
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	OTHER SALES TO					
2	PUBLIC AUTHORITIES					
3	SG1 Small Gen. Service	1,935	105,279	34	56,912	0.0544
4	LP4 Large Power Service	19,412	713,137	1	19,412,000	0.0367
5	LP5 Large Power Service	13,597	475,250	1	13,597,000	0.0350
6	PT2 Opt. LPS Time-of-Use	89,948	3,006,251	1	89,948,000	0.0334
7	PT4 Opt. LPS Time-of-Use	31,763	1,099,871	1	31,763,000	0.0346
8	L4 All Night Outdoor Lighting	36	3,300	6	6,000	0.0917
9	MP Municipal Pump Service	620	33,887	21	29,524	0.0547
10	M33 Rate Rider		632,705			
11	ECR Energy Cost Recovery Rider		2,805,674			
12	PCA Production Costs Allocation R		666,067			
13	EECR Energy Efficiency Cost Rate		677,983			
14	CA Capacity Acquisition Rider		-5			
15	MFA Municipal Franchise Adj		3,609			
16	FLCF Federal Litig Consult Fee		8,974			
17	ANOR ANO1 Interim Capacity Cost		6			
18	CCR Capacity Cost Recovery Rider		120,903			
19	MISO		-121,296			
20	IBRA		60			
21	TOTAL OTHER SALES TO PUB	157,311	10,231,655	65	2,420,169	0.0650
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 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 not 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 long-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)	Average Monthly CP Demand (f)
1	Entergy System Power Pool	OS	94	N/A	N/A	N/A
2	Entergy Louisiana, LLC (1) (legacy)	LU	94	N/A	N/A	N/A
3	Entergy Mississippi, Inc. (1)	IU	94	N/A	N/A	N/A
4	Entergy New Orleans, Inc. (1)	LU	94	N/A	N/A	N/A
5	Entergy Power, LLC (2)	OS	123	N/A	N/A	N/A
6	Conway Corporation (2)	OS	98	N/A	N/A	N/A
7	Jonesboro City Light & Water (2)	OS	151	N/A	N/A	N/A
8	City of Osceola (2)	OS	101	N/A	N/A	N/A
9	City of West Memphis (2)	OS	99	N/A	N/A	N/A
10	Arkansas Electric Cooperative Corp. (2)	OS	82	79	67	67
11	East Texas Electric Cooperative (2)	OS	147	N/A	N/A	N/A
12	Entergy Mississippi, Inc. (2)	OS		N/A	N/A	N/A
13	Entergy Louisiana, LLC (1)	LU		N/A	N/A	N/A
14	Associated Electric Coop., Inc.	RQ	130	0	0	0
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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 not 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 long-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)	Average Monthly CP Demand (f)
1	Midcontinent ISO, Inc.	OS		N/A	N/A	N/A
2						
3						
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, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
			4,410,220	4,410,220	1
585,787	22,788,590	6,714,156		29,502,746	2
732,591	39,386,554	5,921,968		45,308,522	3
753,428	30,522,119	8,552,164		39,074,283	4
		62,211		62,211	5
		41,068		41,068	6
		145,962		145,962	7
		4,666		4,666	8
		20,534		20,534	9
		718,691	767,754	1,486,445	10
		30,867		30,867	11
		233,294		233,294	12
167,559	7,738,161	1,817,318		9,555,479	13
184	3,235	8,236		11,471	14
184	3,235	8,236	0	11,471	
10,219,045	101,170,292	217,211,620	5,177,974	323,559,886	
10,219,229	101,173,527	217,219,856	5,177,974	323,571,357	

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, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
7,979,680	734,868	192,948,721		193,683,589	1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
184	3,235	8,236	0	11,471	
10,219,045	101,170,292	217,211,620	5,177,974	323,559,886	
10,219,229	101,173,527	217,219,856	5,177,974	323,571,357	

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

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

RPCE Settlement accrued in accordance with ER10-1350 Opinion No. 545.

Schedule Page: 310 Line No.: 2 Column: a

(1) Energy and capacity sales associated with the Resource Plan.

Entergy Louisiana and Entergy Gulf States Louisiana Business Combination

As approved in FERC Docket EC15-47-000, on October 1, 2015, Entergy Gulf States Louisiana and Entergy Louisiana entered into a transaction in which Entergy Gulf States Louisiana and Entergy Louisiana combined their respective assets and liabilities into a single successor public utility operating company, Entergy Louisiana.

Schedule Page: 310 Line No.: 5 Column: a

(2) Includes revenue associated with Entergy's participation in the MISO market from the co-owners of White Bluff and Independence.

Schedule Page: 310 Line No.: 14 Column: a

Sales provided under a letter agreement effective March 1992.

Schedule Page: 310.1 Line No.: 1 Column: i

Includes energy revenue of \$192,772,396, ancillary revenue of (\$2,630) and uplift revenue of \$178,955 resulting from sales to MISO.

Schedule Page: 310.1 Line No.: 2 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.

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	6,789,481	6,861,102
5	(501) Fuel	264,005,775	340,814,521
6	(502) Steam Expenses	2,916,590	2,491,929
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,558,762	1,523,189
10	(506) Miscellaneous Steam Power Expenses	3,788,205	3,953,545
11	(507) Rents	249,425	192,702
12	(509) Allowances	93,694	77,346
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	279,401,932	355,914,334
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	821,839	840,448
16	(511) Maintenance of Structures	1,067,968	867,022
17	(512) Maintenance of Boiler Plant	13,168,995	11,780,917
18	(513) Maintenance of Electric Plant	4,080,017	3,706,001
19	(514) Maintenance of Miscellaneous Steam Plant	1,693,406	1,744,427
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	20,832,225	18,938,815
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	300,234,157	374,853,149
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	30,681,948	26,334,012
25	(518) Fuel	118,957,002	126,138,306
26	(519) Coolants and Water	6,099,049	6,197,476
27	(520) Steam Expenses	37,645,551	38,385,430
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses	61,463,189	30,066,338
32	(525) Rents	4,671,502	4,430,212
33	TOTAL Operation (Enter Total of lines 24 thru 32)	259,518,241	231,551,774
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	20,163,402	20,095,809
36	(529) Maintenance of Structures	269,152	238,945
37	(530) Maintenance of Reactor Plant Equipment	4,019,332	13,364,024
38	(531) Maintenance of Electric Plant	13,011,091	10,428,305
39	(532) Maintenance of Miscellaneous Nuclear Plant	89,307,807	66,323,890
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	126,770,784	110,450,973
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	386,289,025	342,002,747
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	259,291	218,788
45	(536) Water for Power	178,094	173,881
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses	31,133	613,012
48	(539) Miscellaneous Hydraulic Power Generation Expenses	335,534	313,150
49	(540) Rents	22,981	27,441
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	827,033	1,346,272
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	10,408	5,162
54	(542) Maintenance of Structures	73,564	139,230
55	(543) Maintenance of Reservoirs, Dams, and Waterways	721,651	410,519
56	(544) Maintenance of Electric Plant	147,111	377,979
57	(545) Maintenance of Miscellaneous Hydraulic Plant	66,335	86,700
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	1,019,069	1,019,590
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	1,846,102	2,365,862

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	1,986,209	1,685,887
63	(547) Fuel	472,676	511,390
64	(548) Generation Expenses	1,571,794	1,092,899
65	(549) Miscellaneous Other Power Generation Expenses	3,532,418	4,318,044
66	(550) Rents	91,844	88,914
67	TOTAL Operation (Enter Total of lines 62 thru 66)	7,654,941	7,697,134
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	689,990	693,356
70	(552) Maintenance of Structures	492,896	336,397
71	(553) Maintenance of Generating and Electric Plant	26,083,398	20,858,298
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	492,832	486,132
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	27,759,116	22,374,183
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	35,414,057	30,071,317
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	380,061,839	528,747,759
77	(556) System Control and Load Dispatching	1,179,360	1,268,409
78	(557) Other Expenses	152,603,321	-139,512,948
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	533,844,520	390,503,220
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,257,627,861	1,139,796,295
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	5,550,364	4,599,351
84			
85	(561.1) Load Dispatch-Reliability	138,687	253,833
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	3,151,507	2,413,330
87	(561.3) Load Dispatch-Transmission Service and Scheduling	249,537	452,968
88	(561.4) Scheduling, System Control and Dispatch Services	4,795,710	3,981,240
89	(561.5) Reliability, Planning and Standards Development	753,613	655,396
90	(561.6) Transmission Service Studies	15,561	34,212
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	579,626	643,320
93	(562) Station Expenses	1,323,980	601,944
94	(563) Overhead Lines Expenses	737,170	824,604
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	7,392,220	7,147,114
97	(566) Miscellaneous Transmission Expenses	6,441,797	8,116,745
98	(567) Rents	182,972	160,471
99	TOTAL Operation (Enter Total of lines 83 thru 98)	31,312,744	29,884,528
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	5,279,580	5,341,989
102	(569) Maintenance of Structures	201,678	226,266
103	(569.1) Maintenance of Computer Hardware	5,788	22,044
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	2,023,150	2,570,074
108	(571) Maintenance of Overhead Lines	4,808,727	5,145,120
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	103,235	118,936
111	TOTAL Maintenance (Total of lines 101 thru 110)	12,422,158	13,424,429
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	43,734,902	43,308,957

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		2,745
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	4,066,681	3,766,261
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	4,066,681	3,769,006
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	4,066,681	3,769,006
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	12,618,994	9,860,536
135	(581) Load Dispatching	671,450	641,113
136	(582) Station Expenses	465,218	444,178
137	(583) Overhead Line Expenses	1,177,742	1,943,133
138	(584) Underground Line Expenses	1,516,464	1,562,559
139	(585) Street Lighting and Signal System Expenses	190,331	115,506
140	(586) Meter Expenses	4,527,541	4,416,491
141	(587) Customer Installations Expenses	1,477,862	1,111,186
142	(588) Miscellaneous Expenses	2,781,035	3,002,416
143	(589) Rents	2,379,950	2,233,220
144	TOTAL Operation (Enter Total of lines 134 thru 143)	27,806,587	25,330,338
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	3,047,295	2,862,525
147	(591) Maintenance of Structures	1,162,052	1,094,924
148	(592) Maintenance of Station Equipment	2,810,878	3,123,277
149	(593) Maintenance of Overhead Lines	42,994,406	30,619,142
150	(594) Maintenance of Underground Lines	2,395,765	1,848,445
151	(595) Maintenance of Line Transformers	37,617	59,909
152	(596) Maintenance of Street Lighting and Signal Systems	2,121,624	2,400,573
153	(597) Maintenance of Meters	80,875	119,745
154	(598) Maintenance of Miscellaneous Distribution Plant	1,561,383	1,346,816
155	TOTAL Maintenance (Total of lines 146 thru 154)	56,211,895	43,475,356
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	84,018,482	68,805,694
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	442,117	455,911
160	(902) Meter Reading Expenses	6,495,304	6,662,430
161	(903) Customer Records and Collection Expenses	21,795,428	22,734,877
162	(904) Uncollectible Accounts	7,068,835	6,992,499
163	(905) Miscellaneous Customer Accounts Expenses	41,220	33,948
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	35,842,904	36,879,665

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	817,948	944,604
168	(908) Customer Assistance Expenses	71,493,864	64,858,967
169	(909) Informational and Instructional Expenses	1,074,808	1,209,067
170	(910) Miscellaneous Customer Service and Informational Expenses	1,275,412	1,208,208
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	74,662,032	68,220,846
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	35,690	50,529
175	(912) Demonstrating and Selling Expenses	1,843	5,027
176	(913) Advertising Expenses	299,007	237,548
177	(916) Miscellaneous Sales Expenses	400,008	480,762
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	736,548	773,866
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	36,873,941	37,588,148
182	(921) Office Supplies and Expenses	5,038,798	4,633,328
183	(Less) (922) Administrative Expenses Transferred-Credit		4,501,660
184	(923) Outside Services Employed	24,178,934	26,887,601
185	(924) Property Insurance	30,989,682	29,122,139
186	(925) Injuries and Damages	4,608,190	6,321,720
187	(926) Employee Pensions and Benefits	86,149,181	69,499,452
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	2,477,630	3,320,796
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	497,876	68,089
192	(930.2) Miscellaneous General Expenses	-2,939,634	840,309
193	(931) Rents	5,952,769	4,856,044
194	TOTAL Operation (Enter Total of lines 181 thru 193)	193,827,367	178,635,966
195	Maintenance		
196	(935) Maintenance of General Plant	3,276,069	2,546,032
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	197,103,436	181,181,998
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,697,792,846	1,542,736,327

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)	Average Monthly CP Demand (f)
1	ASSOCIATED UTILITIES	OS				
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	NON-ASSOCIATED UTILITIES					
5	System Purchases From Others	OS				
6	Union Power Partners	OS		N/A	N/A	N/A
7	Midcontinent ISO, Inc.	OS	OATT	N/A	N/A	N/A
8	OTHER NON-UTILITIES					
9	Cross Oil	OS	**	N/A	N/A	N/A
10	North Little Rock Electric Dept	OS		N/A	N/A	N/A
11	Little Rock Wastewater	OS	M23	N/A	N/A	N/A
12	West Memphis	OS	99	N/A	N/A	N/A
13	Capacity Deferrals					
14						
	Total					

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 monthly (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
					5,977,000	5,977,000	2
3,796,887			204,130,068	32,255,377	2,864,240	239,249,685	3
							4
	325,544	220,153					5
3,429,733			20,088,449	75,427,033		95,515,482	6
972,644			-38,888	38,109,399	350,693	38,421,204	7
							8
502				13,911		13,911	9
277				22,100		22,100	10
310				7,617		7,617	11
4,800			161,308	233,429		394,737	12
					460,103	460,103	13
							14
8,205,153	325,544	220,153	224,340,937	146,068,866	9,652,036	380,061,839	

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2015/Q4
FOOTNOTE DATA			

Schedule Page: 326 Line No.: 2 Column: l

RPCE Settlement accrued in accordance with ER10-1350 Opinion No. 545.

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 \$8,826,627 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 and Entergy Mississippi Grand Gulf purchased power obligations with System Energy Resources and (\$5,962,387) related to GGART.

Schedule Page: 326 Line No.: 7 Column: k

	CHARGES	MWH
MISO Ancillary	\$940,134	-
MISO Congestion	(13,600,328)	-
MISO Energy Purchases	28,671,584	972,644
MISO Losses	19,051,285	-
MISO Uplift	3,046,724	-
	-----	-----
Total Energy Purchases from MISO	\$38,109,399	972,644
	=====	=====

Schedule Page: 326 Line No.: 7 Column: l

Represents MISO administrative charges.

Schedule Page: 326 Line No.: 9 Column: c

FERC rate schedules are classified as special contract PPAs.

Schedule Page: 326 Line No.: 13 Column: a

Deferral of capacity related to Union Power Partners, West Memphis, and MISO Capacity Auction Revenues.

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	MISO	Various	Various	
2	Duke Energy			
3				
4				
5				
6				
7				
8				
9				
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				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred 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 (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
	Various	Various				1
						2
						3
						4
						5
						6
						7
						8
						9
						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
			0	0		0

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred 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.
	71,432,796		71,432,796	1
		-629	-629	2
				3
				4
				5
				6
				7
				8
				9
				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
0	71,432,796	-629	71,432,167	

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

Schedule Page: 328 Line No.: 2 Column: m

Represents transmission revenue adjustment for the write off of an incorrect invoiced amount sent to Duke Energy in December 2004.

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) 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.
4. In column (c) 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 (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
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	TOTAL				

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		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Megawatt-hours Received (c)	Megawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Arkansas Electric							
2	Cooperative Corp.				218,274			218,274
3								
4	Southwestern Power				342,451			342,451
5	Administration							
6								
7	Midcontinent				6,831,495			6,831,495
8	Independent							
9	System Operator Inc							
10								
11								
12								
13								
14								
15								
16								
	TOTAL				7,392,220			7,392,220

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

Schedule Page: 332 Line No.: 1 Column: a

The agreement between Entergy Arkansas and Arkansas Electric Cooperative Corporation was amended in February 1995. Based on the new agreement, Entergy Arkansas pays a monthly demand charge for the use of the wheeling services.

Schedule Page: 332 Line No.: 4 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.: 7 Column: a

The Utility Operating Companies are transmission owning members of the Midcontinent Independent System Operator (MISO) RTO. MISO is the transmission provider under the MISO Attachment O. Entergy Arkansas incurred charges from MISO for the purchase of network transmission service under the MISO Attachment O. MISO calculated the network service charges applicable to Entergy Arkansas and billed the entity for such service.

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	736,550
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	403,898
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000	
6	5% Surcharge on regulated company billings	
7	to non-regulated affiliates	-1,661,241
8	Purchasing and Contracts support	390,500
9	System Aircraft	62,121
10	Section 263A research - tax services	73,632
11	Irrigation load control amortization	964,469
12	Co-owner credits - Independence	-2,983,094
13	Co-owner credits - Ritchie	-98,184
14	Co-owner credits - White Bluff	-1,607,128
15	Securitization financing costs	20,728
16	Directors meetings and expenses	17,291
17	MISO cost amortization	16,484
18	Union labor costs write-off	588,487
19	General litigation	60,792
20	Miscellaneous account write-offs	67,310
21	Other	7,751
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	-2,939,634

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of acquisition adjustments)

- 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).
- 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.
- 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.
- 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			15,791,076		15,791,076
2	Steam Production Plant	15,524,694	-103,937			15,420,757
3	Nuclear Production Plant	64,295,256	2,208,084			66,503,340
4	Hydraulic Production Plant-Conventional	858,378	-2,188			856,190
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	20,194,638	-23			20,194,615
7	Transmission Plant	30,563,046				30,563,046
8	Distribution Plant	76,681,802				76,681,802
9	Regional Transmission and Market Operation					
10	General Plant	20,071,395				20,071,395
11	Common Plant-Electric					
12	TOTAL	228,189,209	2,101,936	15,791,076		246,082,221

B. Basis for Amortization Charges

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	Prod Steam:						
13	Independence Com. 311	11,135	118.00	-49.00	2.20	R3	32.00
14	Independence Com. 312	17,823	108.00	-49.00	2.45	R1.5	31.00
15	Independence Com. 314	865	81.00	-49.00	2.23	R2.5	30.00
16	Independence Com. 315	821	111.00	-49.00	3.06	R3	32.00
17	Independence Com. 316	1,907	111.00	-49.00	2.55	R3	32.00
18	Independence Un. 1 311	976	118.00	-6.00	0.72	R3	32.00
19	Independence Un. 1 312	80,916	108.00	-6.00	1.06	R1.5	31.00
20	Independence Un. 1 314	33,293	81.00	-6.00	0.78	R2.5	30.00
21	Independence Un. 1 315	12,991	111.00	-6.00	0.74	R3	32.00
22	Independence Un. 1 316	2,090	111.00	-6.00	0.82	R3	32.00
23	Lake Cath. Com. 311	1,463	118.00	-421.00	32.51	R3	13.00
24	Lake Cath. Com. 312	492	108.00	-421.00	32.13	R1.5	13.00
25	Lake Cath. Com. 314	139	81.00	-421.00	33.89	R2.5	13.00
26	Lake Cath. Com. 315	287	111.00	-421.00	30.78	R3	13.00
27	Lake Cath. Com. 316	1,104	111.00	-421.00	32.72	R3	13.00
28	Lake Cath. Un. 4 311	4,893	118.00	-20.00	0.13	R3	13.00
29	Lake Cath. Un. 4 312	31,233	108.00	-20.00	0.52	R1.5	13.00
30	Lake Cath. Un. 4 314	16,803	81.00	-20.00		R2.5	13.00
31	Lake Cath. Un. 4 315	6,937	111.00	-20.00	0.65	R3	13.00
32	Lake Cath. Un. 4 316	508	111.00	-20.00	2.77	R3	13.00
33	White Blf. Com. 311	4,570	118.00	-80.00	4.66	R3	29.00
34	White Blf. Com. 312	47,518	108.00	-80.00	5.54	R1.5	29.00
35	White Blf. Com. 314	1,246	81.00	-80.00	4.41	R2.5	29.00
36	White Blf. Com. 315	1,736	111.00	-80.00	4.24	R3	29.00
37	White Blf. Com. 316	3,251	111.00	-80.00	4.64	R3	29.00
38	White Blf. Skl. Ctr 311	340	118.00		0.51	R3	29.00
39	White Blf. Skl. Ctr 315	26	111.00		0.40	R3	29.00
40	White Blf. Skl. Ctr 316	644	111.00		0.21	R3	29.00
41	White Blf. Un. 1 311	34,415	118.00	-5.00	0.58	R3	29.00
42	White Blf. Un. 1 312	145,385	108.00	-5.00	1.24	R1.5	28.00
43	White Blf. Un. 1 314	39,359	81.00	-5.00	0.92	R2.5	28.00
44	White Blf. Un. 1 315	20,077	111.00	-5.00	0.71	R3	29.00
45	White Blf. Un. 1 316	2,968	111.00	-5.00	0.70	R3	29.00
46	White Blf. Un. 2 311	7,008	118.00	-5.00	0.58	R3	29.00
47	White Blf. Un. 2 312	137,880	108.00	-5.00	1.22	R1.5	28.00
48	White Blf. Un. 2 314	48,891	81.00	-5.00	1.07	R2.5	28.00
49	White Blf. Un. 2 315	16,327	111.00	-5.00	1.22	R3	29.00
50	White Blf. Un. 2 316	1,117	111.00	-5.00	0.70	R3	29.00

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	Couch Com. 311_RES	1,759			10.00		
13	Couch Com. 312_RES	58			10.00		
14	Couch Com. 314_RES	115			10.00		
15	Couch Com. 315_RES	714			10.00		
16	Couch Com. 316_RES	620			10.00		
17	Couch Un. 1 311_RES	536			10.00		
18	Couch Un. 1 312_RES	667			10.00		
19	Couch Un. 1 314_RES	489			10.00		
20	Couch Un. 1 315_RES	433			10.00		
21	Couch Un. 1 316_RES	107			10.00		
22	Couch Un. 2 311_RES	72			10.00		
23	Couch Un. 2 312_RES	554			10.00		
24	Couch Un. 2 314_RES	919			10.00		
25	Couch Un. 2 315_RES	-117			10.00		
26	Couch Un. 2 316_RES	4			10.00		
27	Lake Cath. Un 1 311_RES	7			10.00		
28	Lake Cath. Un 1 312_RES	357			10.00		
29	Lake Cath. Un 1 314_RES	-5			10.00		
30	Lake Cath. Un 1 315_RES	543			10.00		
31	Lake Cath. Un 1 316_RES	-2			10.00		
32	Lake Cath. Un 2 311_RES	34			10.00		
33	Lake Cath. Un 2 312_RES	323			10.00		
34	Lake Cath. Un 2 314_RES	36			10.00		
35	Lake Cath. Un 2 315_RES	461			10.00		
36	Lake Cath. Un 2 316_RES	4			10.00		
37	Lake Cath. Un 3 311_RES	26			10.00		
38	Lake Cath. Un 3 312_RES	586			10.00		
39	Lake Cath. Un 3 314_RES	416			10.00		
40	Lake Cath. Un 3 315_RES	661			10.00		
41	Lake Cath. Un 3 316_RES	10			10.00		
42	Lynch Com. 311_RES	3,845			10.00		
43	Lynch Com. 314_RES	32			10.00		
44	Lynch Com. 315_RES	422			10.00		
45	Lynch Com. 316_RES	97			10.00		
46	Lynch Un. 1 311_RES	1,097			10.00		
47	Lynch Un. 1 312_RES	57			10.00		
48	Lynch Un. 1 315_RES	239			10.00		
49	Lynch Un. 1 316_RES	124			10.00		
50	Lynch Un. 2 311_RES	4			10.00		

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 Un. 2 312_RES	742			10.00		
13	Lynch Un. 2 314_RES	503			10.00		
14	Lynch Un. 2 315_RES	217			10.00		
15	Lynch Un. 2 316_RES	96			10.00		
16	Lynch Un. 3 311_RES	-211			10.00		
17	Lynch Un. 3 312_RES	-454			10.00		
18	Lynch Un. 3 314_RES	-383			10.00		
19	Lynch Un. 3 315_RES	199			10.00		
20	Lynch Un. 3 316_RES	27			10.00		
21	Ritc. Com. 311_RES	3,123			10.00		
22	Ritc. Com. 312_RES	1,112			10.00		
23	Ritc. Com. 314_RES	162			10.00		
24	Ritc. Com. 315_RES	150			10.00		
25	Ritc. Com. 316_RES	652			10.00		
26	Ritc. Un. 1 311_RES	133			10.00		
27	Ritc. Un. 1 312_RES	-224			10.00		
28	Ritc. Un. 1 314_RES	-1,081			10.00		
29	Ritc. Un. 1 315_RES	-138			10.00		
30	Ritc. Un. 1 316_RES	16			10.00		
31	Moses Com. 311_RES	597			10.00		
32	Moses Com. 312_RES	2,602			10.00		
33	Moses Com. 316_RES	913			10.00		
34	Moses Un. 1 311_RES				10.00		
35	Moses Un. 1 312_RES	-35			10.00		
36	Moses Un. 1 314_RES	211			10.00		
37	Moses Un. 1 315_RES	342			10.00		
38	Moses Un. 1 316_RES	-2			10.00		
39	Moses Un. 2 311_RES				10.00		
40	Moses Un. 2 312_RES	-36			10.00		
41	Moses Un. 2 314_RES	170			10.00		
42	Moses Un. 2 315_RES	312			10.00		
43	Moses Un. 2 316_RES	-2			10.00		
44	Total Prod Steam	765,447					
45							
46	Prod Nuclear:						
47	ANO Un. 1 320.2	1,598	70.00		2.26	SQ	28.00
48	ANO Com. 321.2	205,632	93.00	-4.00	2.11	R2	28.00
49	ANO Un. 1 321.2	138,503	93.00	-5.00	1.39	R2	22.00
50	ANO Un. 2 321.2	229,977	93.00	-7.00	1.35	R2	27.00

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	ANO Com. 322	29,854	41.00	-4.00	2.63	R1.5	24.00
13	ANO Un. 1 322	535,108	41.00	-5.00	3.96	R1.5	19.00
14	ANO Un. 2 322	656,607	41.00	-7.00	3.03	R1.5	22.00
15	ANO Com. 323	6,286	80.00	-4.00	2.35	R1.5	27.00
16	ANO Un. 1 323	155,089	80.00	-5.00	1.69	R1.5	21.00
17	ANO Un. 2 323	174,009	80.00	-7.00	1.95	R1.5	27.00
18	ANO Com. 324	25,739	104.00	-4.00	1.65	R1.5	27.00
19	ANO Un. 1 324	117,200	104.00	-5.00	1.51	R1.5	22.00
20	ANO Un. 2 324	150,292	104.00	-7.00	1.18	R1.5	27.00
21	ANO Com. 325	133,811	65.00	-4.00	2.03	R2.5	27.00
22	ANO Un. 1 325	100,080	65.00	-5.00	1.16	R2.5	21.00
23	ANO Un. 2 325	55,919	65.00	-7.00	1.14	R2.5	26.00
24	Total Prod Nuclear	2,715,703					
25							
26	Prod Hydro:						
27	Carpenter Com. 330.2	267	75.00		1.89	SQ	40.00
28	Carpenter Com. 331.1	340	253.00	-15.00	2.32	S0.5	40.00
29	Carpenter Com. 331.2	30	253.00	-15.00	1.48	S0.5	40.00
30	Carpenter Com. 331.3	272	253.00	-15.00	1.85	S0.5	40.00
31	Carpenter Com. 332.1	2,398	194.00	-15.00	1.87	L3	40.00
32	Carpenter Com. 332.3	10	194.00	-15.00	1.87	L3	40.00
33	Carpenter Com. 333	908	67.00	-15.00	2.71	L2	37.00
34	Carpenter Com. 334	2,349	107.00	-15.00	2.89	L0	36.00
35	Carpenter Com. 335.1	1,287	168.00	-15.00	2.21	R0.5	38.00
36	Carpenter Com. 335.2	12	168.00	-15.00	2.41	R0.5	38.00
37	Carpenter Com. 335.3	292	168.00	-15.00	2.42	R0.5	38.00
38	Carpenter Un. 1 331.1	533	253.00	-15.00	0.34	S0.5	39.00
39	Carpenter Un. 1 331.3	9	253.00	-15.00	0.72	S0.5	39.00
40	Carpenter Un. 1 332.1	1,356	194.00	-15.00	0.63	L3	39.00
41	Carpenter Un. 1 333	4,311	67.00	-15.00	3.07	L2	37.00
42	Carpenter Un. 1 334	135	107.00	-15.00		L0	34.00
43	Carpenter Un. 1 335.1	99	168.00	-15.00	0.36	R0.5	38.00
44	Carpenter Un. 1 335.3	3	168.00	-15.00	1.08	R0.5	38.00
45	Carpenter Un. 2 331.1	533	253.00	-15.00	0.34	S0.5	39.00
46	Carpenter Un. 2 331.3	9	253.00	-15.00	0.72	S0.5	39.00
47	Carpenter Un. 2 332.1	1,376	194.00	-15.00	0.58	L3	39.00
48	Carpenter Un. 2 333	5,516	67.00	-15.00	2.43	L2	36.00
49	Carpenter Un. 2 334	322	107.00	-15.00	1.19	L0	35.00
50	Carpenter Un. 2 335.1	101	168.00	-15.00		R0.5	38.00

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	Carpenter Un. 2 335.3	3	168.00	-15.00	1.08	R0.5	38.00
13	Rommel Com. 331.1	521	253.00	-15.00	2.10	S0.5	40.00
14	Rommel Com. 331.2	18	253.00	-15.00	1.60	S0.5	40.00
15	Rommel Com. 331.3	324	253.00	-15.00	1.48	S0.5	40.00
16	Rommel Com. 332.1	8,297	194.00	-15.00	2.14	L3	40.00
17	Rommel Com. 332.2	36	194.00	-15.00	2.14	L3	40.00
18	Rommel Com. 333	794	67.00	-15.00	2.68	L2	36.00
19	Rommel Com. 334	463	107.00	-15.00	2.93	L0	37.00
20	Rommel Com. 335.1	377	168.00	-15.00	2.92	R0.5	38.00
21	Rommel Un. 1 331.1	51	253.00	-15.00		S0.5	39.00
22	Rommel Un. 1 331.2	12	253.00	-15.00	1.63	S0.5	39.00
23	Rommel Un. 1 331.3	1	253.00	-15.00	0.66	S0.5	39.00
24	Rommel Un. 1 332.1	513	194.00	-15.00	0.70	L3	39.00
25	Rommel Un. 1 333	1,495	67.00	-15.00	2.44	L2	36.00
26	Rommel Un. 1 334	123	107.00	-15.00	0.91	L0	35.00
27	Rommel Un. 1 335.1	14	168.00	-15.00	0.60	R0.5	38.00
28	Rommel Un. 2 331.1	74	253.00	-15.00	0.03	S0.5	40.00
29	Rommel Un. 2 331.2	25	253.00	-15.00	1.67	S0.5	40.00
30	Rommel Un. 2 331.3	1	253.00	-15.00	0.69	S0.5	40.00
31	Rommel Un. 2 332.1	513	194.00	-15.00	0.70	L3	39.00
32	Rommel Un. 2 333	1,459	67.00	-15.00	2.88	L2	37.00
33	Rommel Un. 2 334	32	107.00	-15.00	0.41	L0	34.00
34	Rommel Un. 2 335.1	14	168.00	-15.00	0.60	R0.5	38.00
35	Rommel Un. 3 331.1	77	253.00	-15.00	0.02	S0.5	39.00
36	Rommel Un. 3 331.2	11	253.00	-15.00	1.64	S0.5	39.00
37	Rommel Un. 3 331.3	1	253.00	-15.00	0.66	S0.5	39.00
38	Rommel Un. 3 332.1	513	194.00	-15.00	0.70	L3	39.00
39	Rommel Un. 3 333	3,248	67.00	-15.00	1.44	L2	30.00
40	Rommel Un. 3 334	32	107.00	-15.00	0.41	L0	34.00
41	Rommel Un. 3 335.1	14	168.00	-15.00	0.60	R0.5	38.00
42	Total Prod Hydro	41,525					
43							
44	Prod Other:						
45	Hot Spring Block 1 341	14,482	30.00	-10.00	5.62	SQ	20.00
46	Hot Spring Block 1 342	1,418	30.00	-10.00	5.62	SQ	20.00
47	Hot Spring Block 1 343	10,176	30.00	-10.00	5.62	SQ	20.00
48	Hot Spring Block 1 344	192,539	30.00	-10.00	5.62	SQ	20.00
49	Hot Spring Block 1 345	1,879	30.00	-10.00	5.62	SQ	20.00
50	Hot Spring Block 1 346	1,481	30.00	-10.00	5.62	SQ	20.00

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 Di. Un. 1 343_RES	165			10.00		
13	Mabe. G Tur U2 341_RES	-1			10.00		
14	Mabe. G Tur U2 342_RES	-3			10.00		
15	Mabe. G Tur U2 343_RES	226			10.00		
16	Mabe. G Tur U2 344_RES	47			10.00		
17	Mabe. G Tur U2 345_RES	418			10.00		
18	Mabe. G Tur U2 346_RES				10.00		
19	Mabe. G Tur U4 341_RES	1			10.00		
20	Mabe. G Tur U4 342_RES	-2			10.00		
21	Mabe. G Tur U4 343_RES	189			10.00		
22	Mabe. G Tur U4 344_RES	54			10.00		
23	Mabe. G Tur U4 345_RES	384			10.00		
24	Mabe. G Tur U4 346_RES				10.00		
25	Mabe. Un. 1 341	124	52.00	-10.00	19.56	R0.5	4.00
26	Mabe. Un. 1 342	58	55.00	-10.00	0.67	SQ	4.00
27	Mabe. Un. 1 343	1,526	44.00	-10.00	6.93	S6	4.00
28	Mabe. Un. 1 344	420	63.00	-10.00	2.03	S0.5	4.00
29	Mabe. Un. 1 345	992	48.00	-10.00	19.16	S4	4.00
30	Mabe. Un. 1 346	8	55.00	-10.00	4.77	R3	4.00
31	Mabe. Un. 3 341	106	52.00	-10.00	21.70	R0.5	4.00
32	Mabe. Un. 3 342	49	55.00	-10.00	0.07	SQ	4.00
33	Mabe. Un. 3 343	1,412	44.00	-10.00	6.32	S6	4.00
34	Mabe. Un. 3 344	349	63.00	-10.00		S0.5	4.00
35	Mabe. Un. 3 345	104	48.00	-10.00	8.31	S4	4.00
36	Mabe. Un. 3 346	3	55.00	-10.00		R3	4.00
37	Ouachita Com. 341	7,780	52.00	-10.00	4.86	R0.5	20.00
38	Ouachita Com. 342	123	55.00	-10.00	4.89	SQ	22.00
39	Ouachita Com. 343	7,264	44.00	-10.00	4.52	S6	22.00
40	Ouachita Com. 344	11,234	63.00	-10.00	4.56	S0.5	22.00
41	Ouachita Com. 345	607	48.00	-10.00	4.53	S4	22.00
42	Ouachita Com. 346	1,172	55.00	-10.00	4.70	R3	22.00
43	Ouachita Gas Yard 342	2,217	55.00	-10.00	4.89	SQ	22.00
44	Ouachita Un. 1 341	3,235	52.00	-10.00	4.83	R0.5	20.00
45	Ouachita Un. 1 342	41	55.00	-10.00	4.89	SQ	22.00
46	Ouachita Un. 1 343	2,274	44.00	-10.00	4.68	S6	22.00
47	Ouachita Un. 1 344	53,657	63.00	-10.00	4.59	S0.5	22.00
48	Ouachita Un. 1 345	430	48.00	-10.00	4.51	S4	22.00
49	Ouachita Un. 1 346	196	55.00	-10.00	4.75	R3	22.00
50	Ouachita Un. 2 341	3,225	52.00	-10.00	4.83	R0.5	20.00

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	Ouachita Un. 2 342	37	55.00	-10.00	4.89	SQ	22.00
13	Ouachita Un. 2 343	2,366	44.00	-10.00	4.67	S6	22.00
14	Ouachita Un. 2 344	53,867	63.00	-10.00	4.57	S0.5	22.00
15	Ouachita Un. 2 345	427	48.00	-10.00	4.54	S4	22.00
16	Ouachita Un. 2 346	162	55.00	-10.00	4.76	R3	22.00
17	Ritc. G Tur Un3 341_RES	19			10.00		
18	Ritc. G Tur Un3 342_RES	30			10.00		
19	Ritc. G Tur Un3 343_RES	265			10.00		
20	Ritc. G Tur Un3 344_RES	97			10.00		
21	Ritc. G Tur Un3 345_RES	22			10.00		
22	Ritc. G Tur Un3 346_RES				10.00		
23	Total Prod Other	379,352					
24							
25	Transmission Plant:						
26	Transmission Plt 350.2	10,121	75.00		1.08	S5	45.00
27	Transmission Plt 350.3	42,833	75.00		1.08	S5	45.00
28	Transmission Plt 352	58,462	60.00	-8.00	1.77	R3	41.00
29	Transmission Plt 353	684,061	64.00	-5.00	1.63	R1.5	52.00
30	Transmission Plt 354	142,806	63.00	-40.00	2.23	R4	35.00
31	Transmission Plt 355	390,897	59.00	-33.00	2.26	R0.5	52.00
32	Transmission Plt 356.1	308,455	77.00	-40.00	1.87	R2	59.00
33	Transmission Plt 356.2	11,113	77.00	-40.00	1.87	R2	59.00
34	Transmission Plt 356.3	45,885	77.00	-40.00	1.87	R2	59.00
35	Transmission Plt 357	19	60.00		1.67	S2	53.00
36	Transmission Plt 358	63	55.00		1.49	S2	46.00
37	Transmission Plt 359	1,900	75.00		1.36	S5	72.00
38	Total Transmission Plt	1,696,616					
39							
40	Distribution Plant:						
41	Distribution Plt 360.2	3,543	65.00		0.74	R4	29.00
42	Distribution Plt 361	21,460	61.00	-16.00	1.83	R4	40.00
43	Distribution Plt 362	401,272	65.00	-10.00	1.38	R1	54.00
44	Distribution Plt 364	581,260	42.00	-12.00	2.61	S0.5	29.00
45	Distribution Plt 365.1	462,312	39.00	-3.00	2.69	R1	28.00
46	Distribution Plt 365.2	427	39.00	-3.00	2.69	R1	28.00
47	Distribution Plt 365.3	64,186	39.00	-3.00	2.69	R1	28.00
48	Distribution Plt 366	97,557	40.00	-12.00	3.31	R2	28.00
49	Distribution Plt 367	153,381	38.00	-6.00	1.93	R2.5	25.00
50	Distribution Plt 368.1	742,726	33.00	-9.00	3.26	L0.5	26.00

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 Plt 369.1	155,172	47.00	-35.00	2.67	S1.5	35.00
13	Distribution Plt 369.2	132,455	42.00	-15.00	2.24	S2.5	28.00
14	Distribution Plt 370	134,982	32.00	-1.00	2.60	R1	20.00
15	Distribution Plt 370.1	247	32.00	-1.00	2.60	R1	20.00
16	Distribution Plt 371	41,248	45.00	-5.00	1.52	R2	34.00
17	Distribution Plt 373	90,893	22.00	-5.00	1.52	R1.5	11.00
18	Distribution Plt 373.2	5,065	30.00	-5.00	4.41	R1.5	29.00
19	Total Distribution Plt	3,088,186					
20							
21	RTO:						
22	RTO 382		5.00		20.00	SQ	2.00
23	RTO Total						
24							
25	General Plant:						
26	General Plt 390	95,079	60.00	5.00	1.19	R1	51.00
27	General Plt 391.1	1,555			6.63		
28	General Plt 391.2	9,754			20.00		
29	General Plt 391.3	3,892			6.67		
30	General Plt 393	885			6.67		
31	General Plt 394	14,913			6.67		
32	General Plt 395	1,040			10.00		
33	General Plt 397.1	21,769			10.00		
34	General Plt 397.2	14,080			6.67		
35	General Plt 398	3,830			10.00		
36	General Plt 391.1_RES	2,474			10.00		
37	General Plt 391.2_RES	-8,487			10.00		
38	General Plt 391.3_RES	-398			10.00		
39	General Plt 392_RES	-231			10.00		
40	General Plt 393_RES	-311			10.00		
41	General Plt 394_RES	2,514			10.00		
42	General Plt 395_RES	4,147			10.00		
43	General Plt 396_RES	166			10.00		
44	General Plt 397.1_RES	1,732			10.00		
45	General Plt 397.2_RES	1,269			10.00		
46	General Plt 398_RES	61			10.00		
47	Total General Plt	169,733					
48							
49	Total:	8,856,561					
50							

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	Column balances						
14	represent depreciable						
15	base by utility						
16	account as of						
17	12/31/2015.						
18							
19							
20							
21							
22							
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							
48							
49							
50							

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

Schedule Page: 336 Line No.: 1 Column: d

Includes \$18,332 of service company amortization billing allocations.

Schedule Page: 336 Line No.: 10 Column: b

Includes \$8,387,020 of service company depreciation billing allocations.

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/(Refund)	-12,193		-12,193	
4					
5	Various FERC dockets related to				
6	System Agreement Litigation		85,975	85,975	
7					
8	Docket No. 07-130-TF				
9	APSC consultant fees incurred in federal				
10	cases		1,247,990	1,247,990	1,269,270
11					
12	Other expenses incurred in connection with				
13	various filings before FERC		383	383	
14					
15	ARKANSAS PUBLIC SERVICE COMMISSION				
16	Docket No. 12-056-U				
17	Act 310 Filing		110	110	
18					
19	Docket No. 12-096-TF				
20	EAI Rider AFRCRG Filing		-190	-190	
21					
22	EAI Energy Efficiency		29,413	29,413	
23					
24	Docket No. 13-028-U				
25	2013 EAI Rate Case		-5,820	-5,820	
26					
27	2015 EAI Rate Case		374,736	374,736	
28					
29	Other expenses incurred in connection with				
30	various filings before the APSC		113,098	113,098	
31					
32	OTHER				
33	Expenses incurred in connection with various				
34	filings before the APSC and FERC		586,857	586,857	
35					
36	MISO Transition Costs (1)		10,449	10,449	14,855
37					
38	Other expenses incurred in connection with				
39	OATT, MISO, and Other Transmission related				
40	FERC Dockets (1)		28,260	28,260	
41					
42	Docket No. 15-014-U				
43	SPO NextEra Stuttgart Solar Project		18,562	18,562	
44					
45	Note (1) Transmission Related				
46	TOTAL	-12,193	2,489,823	2,477,630	1,284,125

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 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
							1
							2
Electric	928	-12,193					3
							4
							5
Electric	928	85,975					6
							7
							8
							9
Electric	928	1,247,990		928	405,672	863,598	10
							11
							12
Electric	928	383					13
							14
							15
							16
Electric	928	110					17
							18
							19
Electric	928	-190					20
							21
Electric	928	29,413					22
							23
							24
Electric	928	-5,820					25
							26
Electric	928	374,736					27
							28
							29
Electric	928	113,098					30
							31
							32
							33
Electric	928	586,857					34
							35
Electric	928	10,449		928	10,449	4,406	36
							37
							38
							39
Electric	928	28,260					40
							41
							42
Electric	928	18,562					43
							44
							45
		2,477,630			416,121	868,004	46

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: | a. Overhead |
| (1) Generation | b. Underground |
| a. hydroelectric | (3) Distribution |
| i. Recreation fish and wildlife | (4) Regional Transmission and Market Operation |
| ii Other hydroelectric | (5) Environment (other than equipment) |
| b. Fossil-fuel steam | (6) Other (Classify and include items in excess of \$50,000.) |
| c. Internal combustion or gas turbine | (7) Total Cost Incurred |
| d. Nuclear | B. Electric, R, D & D Performed Externally: |
| e. Unconventional generation | (1) Research Support to the electrical Research Council or the Electric Power Research Institute |
| f. Siting and heat rejection | |
| (2) Transmission | |

Line No.	Classification (a)	Description (b)
1	A(2)	
2	A(3)	
3	A(6)	Other
4	B(1)	EPRI Dues
5	B(1)	EPRI Dues
6	B(1)	EPRI Dues
7	B(1)	EPRI Research
8	B(4)	CEB Leadership Council Dues
9	B(4)	Gartner, Inc. Dues
10	B(4)	Other
11		
12	Total	
13		
14	(1) 107, 108.2, 184, 408.1, 568,592	
15		
16	(2) 107, 568, 580	
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		

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		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
344,085		(1)	344,085		1
6,183		107,588	6,183		2
44,165		107,926	44,165		3
	1,143,055	517	1,143,055		4
	469,599	506	469,599		5
	148,313	930.2	148,313		6
	156,188	524,923	156,188		7
	18,304	930.2	18,304		8
	49,694	930.2	49,694		9
	1,689,406	(2)	1,689,406		10
					11
394,433	3,674,559		4,068,992		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

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 Terminating 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)	46,728,418		46,728,418
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	36,785,459		36,785,459
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	36,785,459		36,785,459
72	Plant Removal (By Utility Departments)			
73	Electric Plant	3,410,165		3,410,165
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	3,410,165		3,410,165
77	Other Accounts (Specify, provide details in footnote):			
78	Fuel Stock Exp Undistributed (Account 152)	4,236,662		4,236,662
79	Stores Expense Undistributed (Account 163)	2,340,163		2,340,163
80	Miscellaneous Current and Accrued Assets (Account 174)	-420,132		-420,132
81	Clearing Accounts (Account 184)	2,837,064		2,837,064
82	Miscellaneous Deferred Debits (Account 186)	-1,935,579		-1,935,579
83	Accumulated Provisions for Property Insurance (Account 2281)	3,413,236		3,413,236
84	Accumulated Miscellaneous Operating Provisions (Account 2284)	858		858
85	PAYROLL TAX (Account 4081)	1,331		1,331
86	Civil, Political, and Related Expenses (Account 4264)	128,671		128,671
87	Other Deductions (Account 4265)	1,209,073		1,209,073
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	11,811,347		11,811,347
96	TOTAL SALARIES AND WAGES	98,735,389		98,735,389

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			
FOOTNOTE DATA			

Schedule Page: 354 Line No.: 96 Column: b

The following payroll charges from Non-Nuclear Affiliate are not included in this schedule and are included in the Electric O&M schedule (pages 320-323) only:

Production:	\$10,458,242
Transmission:	\$7,084,463
Distribution:	\$1,849,891
Customer Accts:	\$4,835,897
Customer Service:	\$373,804
Sales:	\$177,856
Administrative & General:	\$24,063,857

In addition, Nuclear Affiliate production payroll charges of \$101,508,425 and administrative and general charges of \$4,955,939 are not included in this schedule and are included in the Electric O&M schedule(pages 320-323)only.

Name of Respondent Entergy Arkansas, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of <u>2015/Q4</u>
--	---	---------------------------------------	--

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

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)	10,742,305	13,836,104	20,609,278	28,671,584
3	Net Sales (Account 447)	(39,677,709)	(107,473,806)	(165,400,132)	(192,772,396)
4	Transmission Rights				
5	Ancillary Services	251,813	397,071	675,543	942,764
6	Other Items (list separately)				
7	MISO Admin (Account 555)	109,616	218,032	301,535	350,693
8	MISO Congestion (Account 555)	(5,646,043)	(8,877,126)	(12,088,473)	(13,600,328)
9	MISO Losses (Account 555)	4,301,599	10,096,115	16,029,115	19,051,285
10	MISO Uplift (Account 555)	1,042,706	1,352,164	2,609,466	3,046,724
11	MISO Capacity Auction (Account 555)			(22,036)	(38,888)
12	MISO Admin (Account 447)				
13	MISO Congestion (Account 447)				
14	MISO Losses (Account 447)				
15	MISO Uplift (Account 447)	(121,155)	(118,589)	(118,638)	(178,955)
16	MISO Capacity Auction (Account 447)	(283,338)	(532,652)	(628,575)	(734,868)
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					
42					
43					
44					
45					
46	TOTAL	(29,280,206)	(91,102,687)	(138,032,917)	(155,262,385)

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.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
		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						995,332
2	Reactive Supply and Voltage			7,476,286			4,740,961
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)			7,476,286			5,736,293

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

Schedule Page: 398 Line No.: 1 Column: b

Entergy Arkansas is a transmission owning member of Midcontinent Independent Transmission System Operator (MISO) RTO. Entergy Arkansas does not purchase or sell transmission services or ancillary services directly. Instead, Entergy Arkansas receives revenues and incurs expenses from transmission services and ancillary sold by MISO. MISO distributes the revenue that it receives to the transmission owner and the transmission owner pays MISO for the related expenses incurred.

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/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	6,614	8	900	3,623	2,848		143		
2	February	5,593	19	900	3,036	2,414		143		
3	March	5,373	6	800	2,859	2,371		143		
4	Total for Quarter 1				9,518	7,633		429		
5	April	3,981	8	2100	2,119	1,719		143		
6	May	4,962	29	1600	2,801	2,018		143		
7	June	6,572	24	1600	3,760	2,669		143		
8	Total for Quarter 2				8,680	6,406		429		
9	July	7,072	29	1600	3,985	2,944		143		
10	August	6,658	4	1500	3,659	2,856		143		
11	September	6,349	8	1600	3,776	2,430		143		
12	Total for Quarter 3				11,420	8,230		429		
13	October	4,902	12	1700	2,616	2,143		143		
14	November	4,298	23	1000	2,069	2,086		143		
15	December	4,596	19	900	2,497	1,956		143		
16	Total for Quarter 4				7,182	6,185		429		
17	Total Year to Date/Year				36,800	28,454		1,716		

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/Q4

MONTHLY ISO/RTO 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 Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
- (4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
- (5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month	Monthly Peak MW - Total	Day of Monthly Peak	Hour of Monthly Peak	Imports into ISO/RTO	Exports from ISO/RTO	Through and Out Service	Network Service Usage	Point-to-Point Service Usage	Total Usage
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

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)	21,160,228
3	Steam	10,190,223	23	Requirements Sales for Resale (See instruction 4, page 311.)	184
4	Nuclear	13,837,726	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	10,219,045
5	Hydro-Conventional	143,956	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	24,578
7	Other		27	Total Energy Losses	1,078,414
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	32,482,449
9	Net Generation (Enter Total of lines 3 through 8)	24,171,905			
10	Purchases	8,205,153			
11	Power Exchanges:				
12	Received	325,544			
13	Delivered	220,153			
14	Net Exchanges (Line 12 minus line 13)	105,391			
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	32,482,449			

Name of Respondent Entergy Arkansas, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of <u>2015/Q4</u>
--	---	---------------------------------------	--

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-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK		
				Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	2,640,298	649,801	4,035	8	900
30	February	2,236,909	368,576	3,702	27	900
31	March	2,786,004	960,601	3,481	6	900
32	April	2,434,793	1,090,440	2,681	9	1600
33	May	2,962,454	1,287,121	3,253	29	1600
34	June	3,171,652	1,078,658	4,406	24	1700
35	July	3,370,194	933,566	4,665	29	1600
36	August	3,293,445	1,059,835	4,393	7	1700
37	September	2,838,862	881,870	4,110	8	1600
38	October	2,028,947	406,376	3,243	12	1600
39	November	2,112,982	565,910	2,888	23	900
40	December	2,605,909	936,291	2,942	4	900
41	TOTAL	32,482,449	10,219,045			

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 term 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: <i>Hamilton Moses</i> (b)	Plant Name: <i>Cecil Lynch</i> (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	225.20
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	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	0	0
13	Cost of Plant: Land and Land Rights	30708	89504
14	Structures and Improvements	0	640083
15	Equipment Costs	83	113852
16	Asset Retirement Costs	86051	128962
17	Total Cost	116842	972401
18	Cost per KW of Installed Capacity (line 17/5) Including	0.8467	4.3179
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	0	0
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	0	0
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	0	0
35	Expenses per Net KWh	0.0000	0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		
38	Quantity (Units) of Fuel Burned	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000

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: (b)	Plant Name: (c)
		Lake Catherine	Robert Ritchie 3
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam	Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Full Outdoor	Outdoor
3	Year Originally Constructed	1950	1970
4	Year Last Unit was Installed	1970	1970
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	752.00	19.50
6	Net Peak Demand on Plant - MW (60 minutes)	520	0
7	Plant Hours Connected to Load	1253	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	523	0
10	When Limited by Condenser Water	520	0
11	Average Number of Employees	41	0
12	Net Generation, Exclusive of Plant Use - KWh	159375936	0
13	Cost of Plant: Land and Land Rights	33725	40705
14	Structures and Improvements	6974968	0
15	Equipment Costs	57501987	611
16	Asset Retirement Costs	322593	4455
17	Total Cost	64833273	45771
18	Cost per KW of Installed Capacity (line 17/5) Including	86.2145	2.3472
19	Production Expenses: Oper, Supv, & Engr	2543144	0
20	Fuel	15950313	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	723608	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	542501	0
26	Misc Steam (or Nuclear) Power Expenses	1531272	0
27	Rents	112267	0
28	Allowances	1223	0
29	Maintenance Supervision and Engineering	288022	0
30	Maintenance of Structures	127150	0
31	Maintenance of Boiler (or reactor) Plant	1130548	0
32	Maintenance of Electric Plant	264598	0
33	Maintenance of Misc Steam (or Nuclear) Plant	288882	0
34	Total Production Expenses	23503528	0
35	Expenses per Net KWh	0.1475	0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF	
38	Quantity (Units) of Fuel Burned	0	1981150
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	1021786
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	8.051
42	Average Cost of Fuel Burned per Million BTU	0.000	7.879
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.100
44	Average BTU per KWh Net Generation	0.000	12701.480

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 term 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: <i>White Bluff</i> (b)	Plant Name: <i>Independence</i> (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	1980	1983
4	Year Last Unit was Installed	1981	1983
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	1026.00	283.50
6	Net Peak Demand on Plant - MW (60 minutes)	1645	1719
7	Plant Hours Connected to Load	8400	5738
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	1639	1681
10	When Limited by Condenser Water	1637	1681
11	Average Number of Employees	134	115
12	Net Generation, Exclusive of Plant Use - KWh	3547221907	875413711
13	Cost of Plant: Land and Land Rights	1109655	773576
14	Structures and Improvements	46333430	12112139
15	Equipment Costs	466422952	150705384
16	Asset Retirement Costs	2924163	655933
17	Total Cost	516790200	164247032
18	Cost per KW of Installed Capacity (line 17/5) Including	503.6942	579.3546
19	Production Expenses: Oper, Supv, & Engr	3349000	893432
20	Fuel	95086531	26221688
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	1703833	489149
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	613074	403186
26	Misc Steam (or Nuclear) Power Expenses	2680506	-429673
27	Rents	101409	35749
28	Allowances	21648	17602
29	Maintenance Supervision and Engineering	461196	72621
30	Maintenance of Structures	769734	171083
31	Maintenance of Boiler (or reactor) Plant	9609111	2429336
32	Maintenance of Electric Plant	3141910	673508
33	Maintenance of Misc Steam (or Nuclear) Plant	1057644	346881
34	Total Production Expenses	118595596	31324562
35	Expenses per Net KWh	0.0334	0.0358
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	TON	BBL
38	Quantity (Units) of Fuel Burned	2143095	16318
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	20773557	5899583
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000
41	Average Cost of Fuel per Unit Burned	43.429	123.443
42	Average Cost of Fuel Burned per Million BTU	2.091	20.924
43	Average Cost of Fuel Burned per KWh Net Gen	0.026	0.029
44	Average BTU per KWh Net Generation	0.000	12577.723

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: <i>Harvey Couch</i> (d)				Plant Name: <i>Mabelvale</i> (e)				Plant Name: <i>Robert Ritchie 1</i> (f)				Line No.
Steam				Gas Turbine				Steam				1
Full Outdoor				Outdoor				Outdoor				2
1943				1970				1961				3
1954				1970				1961				4
182.70				78.00				359.00				5
0				0				0				6
0				0				0				7
0				0				0				8
0				32				0				9
0				28				0				10
0				0				0				11
0				5000				0				12
9722				0				40704				13
792256				230772				10				14
254787				4919785				447				15
114735				17821				123276				16
1171500				5168378				164437				17
6.4122				66.2613				0.4580				18
0				1319				0				19
0				472676				0				20
0				0				0				21
0				0				0				22
0				0				0				23
0				0				0				24
0				0				0				25
0				12676				0				26
0				0				0				27
0				0				0				28
0				0				0				29
0				1446				0				30
0				0				0				31
0				11012				0				32
0				9217				0				33
0				508346				0				34
0.0000				101.6692				0.0000				35
				Gas								36
				MCF								37
0	0	0	0	0	0	0	0	0	0	0	38	
0	0	0	0	0	0	0	0	0	0	0	39	
0.000	0.000	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	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41	
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42	
0.000	0.000	0.000	0.000	94.535	0.000	0.000	0.000	0.000	0.000	0.000	43	
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44	

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: <i>Ouachita 1 & 2</i> (d)		Plant Name: <i>Hot Spring</i> (e)		Plant Name: <i>Arkansas Nuclear One</i> (f)		Line No.			
	Gas Turbine		Gas Turbine		Nuclear		1		
	Outdoor		Outdoor		N/A		2		
	2002		2002		1974		3		
	2002		2002		1980		4		
	602.60		714.80		1978.00		5		
	567		633		1869		6		
	8350		5553		7832		7		
	0		0		0		8		
	538		604		1824		9		
	488		615		1824		10		
	27		22		967		11		
	3109657534		2498548586		13837726025		12		
	332811		1925137		2648089		13		
	152705984		119677683		574111206		14		
	139373482		207492550		2139993369		15		
	0		0		110910357		16		
	292412277		329095370		2827663021		17		
	485.2510		460.4020		1429.5566		18		
	1017854		970941		30681948		19		
	63982657		62663145		118957002		20		
	0		0		6099049		21		
	0		0		37645551		22		
	0		0		0		23		
	0		0		0		24		
	616440		955355		0		25		
	1997035		1528807		61463189		26		
	37465		54379		4671502		27		
	15313		37908		0		28		
	40819		649171		20163402		29		
	157744		333707		269152		30		
	0		0		4019332		31		
	11103617		14968770		13011091		32		
	183652		299962		89307807		33		
	79152596		82462145		386289025		34		
	0.0255		0.0330		0.0279		35		
	Gas		Gas		Nuclear		36		
	MCF		MCF		MWH Therm		37		
0	21964619	0	0	18349029	0	0	42065655	0	38
0	1037881	0	0	1031372	0	0	3413257	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	2.913	0.000	0.000	3.415	0.000	0.000	2.828	0.000	41
0.000	2.807	0.000	0.000	3.311	0.000	0.000	0.829	0.000	42
0.000	0.021	0.000	0.000	0.025	0.000	0.000	0.009	0.000	43
0.000	7330.920	0.000	0.000	7574.260	0.000	0.000	10376.050	0.000	44

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/Q4

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: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35
			36
		BBL	37
0	0	0	38
0	0	0	39
0.000	0.000	0.000	40
0.000	0.000	0.000	41
0.000	0.000	0.000	42
0.000	0.000	0.000	43
0.000	0.000	0.000	44

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

Schedule Page: 402 Line No.: -1 Column: b

Hamilton Moses Units 1 and 2 were in retired status for the entire year.

Schedule Page: 402 Line No.: -1 Column: c

Cecil Lynch Units 2 and 3 were in retired status for the entire year.

Schedule Page: 403 Line No.: -1 Column: d

Harvey Couch Units 1 and 2 were in retired status for the entire year.

Schedule Page: 403 Line No.: -1 Column: e

Mabelvale Units 2 and 4 were in retired status for the entire year.

Schedule Page: 403 Line No.: -1 Column: f

Robert Ritchie Unit 1 was in retired status for the entire year.

Schedule Page: 403 Line No.: 1 Column: f

Reflects Entergy Arkansas's 100% interest in Robert Ritchie Unit 1 and its 40.74% interest in Common Plant.

Schedule Page: 402.1 Line No.: -1 Column: b

Lake Catherine Units 1, 2 and 3 were in retired status for the entire year.

Schedule Page: 402.1 Line No.: -1 Column: c

Robert Ritchie Unit 3 was in retired status for the entire year.

Schedule Page: 403.1 Line No.: -1 Column: d

Reflects Entergy Arkansas's 100% interest in Ouachita Units 1 and 2 and its 66.7% interest in Common Plant.

Schedule Page: 402.1 Line No.: 1 Column: c

Reflects Entergy Arkansas's 100% interest in Robert Ritchie Unit 3 and its 40.74% interest in Common Plant.

Schedule Page: 402.2 Line No.: -1 Column: b

Reflects Entergy Arkansas's 57% interest in White Bluff Units 1, 2 and Common Plant.

Schedule Page: 402.2 Line No.: -1 Column: c

Reflects Entergy Arkansas's 31.5% interest in Independence Unit 1 and its 15.75% interest in Common Plant.

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: Rimmel (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)	61	12
7	Plant Hours Connect to Load	3,416	4,685
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	62	12
10	(b) Under the Most Adverse Oper Conditions	62	12
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	104,957,757	38,998,659
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	5,140,178	9,871,624
17	Equipment Costs	15,337,843	8,067,034
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	6,187	1,154
20	TOTAL cost (Total of 14 thru 19)	23,271,448	19,299,665
21	Cost per KW of Installed Capacity (line 20 / 5)	415.5616	2,144.4072
22	Production Expenses		
23	Operation Supervision and Engineering	129,328	129,963
24	Water for Power	91,846	86,248
25	Hydraulic Expenses	0	0
26	Electric Expenses	175	30,958
27	Misc Hydraulic Power Generation Expenses	232,579	102,955
28	Rents	14,926	8,055
29	Maintenance Supervision and Engineering	4,879	5,529
30	Maintenance of Structures	65,397	8,167
31	Maintenance of Reservoirs, Dams, and Waterways	514,930	206,721
32	Maintenance of Electric Plant	86,575	60,536
33	Maintenance of Misc Hydraulic Plant	-44,472	110,807
34	Total Production Expenses (total 23 thru 33)	1,096,163	749,939
35	Expenses per net KWh	0.0104	0.0192

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demand on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			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

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						
7						
8						
9						
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						
41						
42						
43						
44						
45						
46						

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/Q4

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		Kind of Fuel (k)	Fuel Costs (in cents per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
248				Oil		1
						2
						3
						4
						5
						6
						7
						8
						9
						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
						41
						42
						43
						44
						45
						46

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 (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	White Bluff	Keo 6010	500.00		Lat Stl A	17.25		1
2	El Dorado	LA St Ln (Secc) 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 Pinnacle	Mayflower 6007	500.00		Lat Stl A	29.93		1
12	ANO	Jct Mablv 6001	500.00		Guyed Alu	48.58		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	1.48		1
16	Jct Mablv	OG&E Connection 6006	500.00		Lat Stl A	85.38		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	0.54		
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-Wdwrdr	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	44.83		1
30	Ritchie	Woodward 6204	230.00		DC Lat St	80.19	8.91	1
31	Ritchie	Miss River (#2) 6206	230.00		DC Lat St	1.55		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	4,700.34	158.26	210

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 (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
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	23.39		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	8.45		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	5.96		1
12	Hayti	Noranda Gen Station 6352	161.00		Wood H-Fr	27.90		1
13	Hayti	AR/MO State Line 6350	161.00		Wood H-Fr	15.99		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	25.26		1
19	Moses	Parkin/Wynne Indl Tap 6328	161.00		Wood H-Fr	3.83		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	47.32	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	32.31		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	4,700.34	158.26	210

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 (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Marked Tree	Lepanto 6322	161.00		Wood H-Fr	9.03		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	41.49		1
5	Hamlet-Hb Spgs S-Gr Fry	(Greenbrair Tap) 6311	161.00		Wood H-Fr	11.97		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	72.01		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	10.22	1.71	1
14	Batesville	Norfolk (Mt View Tap) 6304	161.00		Wood H-Fr	21.05		1
15	Conway West	Morrilton East 6307	161.00		Wood H-Fr	15.27		1
16	Batesville	Norfolk 6303	161.00		Wood H-Fr	48.74		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	80.34		1
20	Gold Creek SW State Line	Sylvan Hills 6312	161.00		Wood H-Fr	19.69		1
21	Newport	Batesville (via ISES) 6331	161.00		Wood H-Fr	19.65	7.77	1
22	Norfolk	Ozk Bch (B: SHLS Tap) 6335	161.00		Wood H-Fr	90.41		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	20.45		1
27	Grandview	Osage Creek 0874	161.00		Sng Concr	5.21		1
28	West Memphis	Ebony 0810	161.00		Sng Concr	8.76		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	Hamlet	Holland Bottom 0819	161.00		Sng Concr	21.20		1
32	Bald Knob	Tetc P Sta # 6 6652	161.00		Wood H-Fr	1.60		1
33	Datto	Corning-Tet Sta 8 6696	161.00		VARIOUS	39.65		1
34		Total 161kv Lines						
35								
36					TOTAL	4,700.34	158.26	210

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 (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1		Total 115			Various	2,009.25	109.39	110
2		Arklahoma - Danville				56.70		1
3		(Leased)						
4								
5		Total 69kv			Wood H-Fr	10.94		2
6								
7	Transmission Lines							
8								
9								
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					TOTAL	4,700.34	158.26	210

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/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)			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)	
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
	37,672,529	273,710,292	311,382,821					21
								22
1024.5 ACAR								23
	934,580	2,733,426	3,668,006					24
								25
1534 ACAR								26
1272 ACSR								27
3070 AACSR								28
1534 ACAR								29
1272 ACSR								30
3070 AACSR								31
	1,864,893	34,720,409	36,585,302					32
								33
666 ACSR								34
336 ACSR								35
	93,494,293	814,113,138	907,607,431	14,528,525	6,510,913	82,150	21,121,588	36

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/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)			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)	
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
	93,494,293	814,113,138	907,607,431	14,528,525	6,510,913	82,150	21,121,588	36

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/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)			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
	26,734,444	255,347,936	282,082,380					34
								35
	93,494,293	814,113,138	907,607,431	14,528,525	6,510,913	82,150	21,121,588	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)	
	26,244,327	247,381,205	273,625,532					1
								2
								3
								4
	43,520	219,870	263,390					5
								6
				14,528,525	6,510,913	82,150	21,121,588	7
								8
								9
								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
	93,494,293	814,113,138	907,607,431	14,528,525	6,510,913	82,150	21,121,588	36

Name of Respondent
 Entergy Arkansas, Inc.

This Report Is:
 (1) An Original
 (2) A Resubmission

Date of Report
 (Mo, Da, Yr)
 / /

Year/Period of Report
 End of 2015/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 completed 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 (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1							
2							
3							
4							
5							
6							
7							
8							
9							
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							
41							
42							
43							
44	TOTAL						

Name of Respondent
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/Q4

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			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
									2
									3
									4
									5
									6
									7
									8
									9
									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
									41
									42
									43
									44

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	

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	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	COFER ROAD	Distrib. Unattended	161.00	13.80	
16	COLLEGE CITY	Distrib. Unattended	34.50	12.40	
17	CONWAY INDUSTRIAL CO	Distrib. Unattended	161.00	13.80	
18	CONWAY SOUTH CO	Distrib. Unattended	161.00	13.80	
19	CONWAY WEST CO	Distrib. Unattended	161.00	13.80	
20	CORNING 115	Distrib. Unattended	115.00	34.50	
21	CORNING 34.5	Distrib. Unattended	34.50	12.40	
22	COTTON PLANT	Distrib. Unattended	115.00	13.80	
23	COTTON PLANT CITY 4160	Distrib. Unattended	13.80	4.80	
24	COUCH SES SWITCHYARD	Distrib. Unattended	115.00	13.80	
25	CROOKED LAKE	Distrib. Unattended	161.00	34.50	
26	CROSSETT NORTH	Distrib. Unattended	115.00	13.80	
27	CROSSETT PAPER MILL	Distrib. Unattended	115.00	13.80	
28	CROSSETT WEST	Distrib. Unattended	115.00	13.80	
29	CUSHMAN	Distrib. Unattended	161.00	13.80	
30	DALARK	Distrib. Unattended	115.00	34.50	
31	DANVILLE (APL)	Distrib. Unattended	161.00	13.80	
32	DARDANELLE	Distrib. Unattended	161.00	13.80	
33	DATTO	Distrib. Unattended	115.00	2.40	
34	DELIGHT	Distrib. Unattended	34.50	13.80	
35	DELL CITY	Distrib. Unattended	34.50	2.40	
36	DERMOTT	Distrib. Unattended	115.00	13.80	
37	DES ARC	Distrib. Unattended	115.00	13.80	
38	DEVALLS BLUFF	Distrib. Unattended	115.00	13.80	
39	DEWITT	Distrib. Unattended	115.00	13.80	
40	DIAMOND CITY	Distrib. Unattended	34.50	13.80	

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	DUMAS	Distrib. Unattended	115.00	13.80	
2	EL DORADO DONAN	Distrib. Unattended	115.00	13.80	
3	EL DORADO EAST	Distrib. Unattended	115.00	13.80	
4	EL DORADO JACKSON	Distrib. Unattended	115.00	13.80	
5	EL DORADO LION OIL	Distrib. Unattended	115.00	13.80	
6	EL DORADO MILL ROAD	Distrib. Unattended	115.00	13.80	
7	EL DORADO MONSANTO	Distrib. Unattended	115.00	13.80	
8	EL DORADO NEWELL	Distrib. Unattended	115.00	13.80	
9	EL DORADO PARKERS CHAPEL	Distrib. Unattended	115.00	13.80	
10	EL DORADO PARNELL ROAD	Distrib. Unattended	115.00	13.80	
11	EL DORADO QUINN	Distrib. Unattended	115.00	13.80	
12	EL DORADO UPLAND	Distrib. Unattended	115.00	13.80	
13	EL DORADO WEST	Distrib. Unattended	115.00	13.80	
14	ELAINE	Distrib. Unattended	115.00	13.80	
15	EMERSON	Distrib. Unattended	115.00	13.80	
16	ENGLAND	Distrib. Unattended	115.00	13.80	
17	EUDORA	Distrib. Unattended	161.00	34.50	
18	EVERTON ROAD	Distrib. Unattended	161.00	13.80	
19	FAULKNER LAKE (NLR)	Distrib. Unattended	115.00	13.80	
20	FISHER	Distrib. Unattended	161.00	13.80	
21	FLIPPIN	Distrib. Unattended	161.00	13.80	
22	FORDYCE	Distrib. Unattended	115.00	13.80	
23	FORDYCE ORIENT	Distrib. Unattended	115.00	13.80	
24	FORREST CITY NORTH	Distrib. Unattended	161.00	13.80	
25	FORREST CITY SOUTH	Distrib. Unattended	161.00	13.80	
26	FOUNTAIN LAKE	Distrib. Unattended	115.00	13.80	
27	FRIENDSHIP	Distrib. Unattended	115.00	13.80	
28	GIFFORD	Distrib. Unattended	115.00	13.80	
29	GILLETT	Distrib. Unattended	115.00	13.80	
30	GILMORE	Distrib. Unattended	161.00	13.80	
31	GLEASON	Distrib. Unattended	161.00	13.80	
32	GLENWOOD	Distrib. Unattended	115.00	13.80	
33	GLENWOOD PUMPING PLANT	Distrib. Unattended	13.80	2.40	
34	GREEN FOREST	Distrib. Unattended	161.00	13.80	
35	GREEN FOREST SOUTH	Distrib. Unattended	161.00	13.80	
36	GREENBRIER	Distrib. Unattended	161.00	13.80	
37	GREENWAY	Distrib. Unattended	34.50	4.80	
38	GRIFFITHVILLE	Distrib. Unattended	115.00	13.80	
39	GUION	Distrib. Unattended	161.00	13.80	
40	GURDON	Distrib. Unattended	115.00	13.80	

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	H.S. ALBRIGHT	Distrib. Unattended	115.00	13.80	
2	H.S. EAST	Distrib. Unattended	115.00	13.80	
3	H.S. INDUSTRIAL	Distrib. Unattended	115.00	13.80	
4	H.S. MILTON	Distrib. Unattended	115.00	13.80	
5	H.S. MT. VALLEY	Distrib. Unattended	115.00	13.80	
6	H.S. NORTH	Distrib. Unattended	115.00	13.80	
7	H.S. ROYAL	Distrib. Unattended	115.00	13.80	
8	H.S. SOUTH	Distrib. Unattended	115.00	13.80	
9	H.S. UNION CARBIDE	Distrib. Unattended	115.00	13.80	
10	H.S. VALLEY STREET	Distrib. Unattended	115.00	13.80	
11	H.S. VILLAGE	Distrib. Unattended	115.00	13.80	
12	H.S. WEST	Distrib. Unattended	115.00	13.80	
13	HAMBURG	Distrib. Unattended	115.00	13.80	
14	HAMLET	Distrib. Unattended	161.00	2.40	
15	HARDIN WEST	Distrib. Unattended	115.00	13.80	
16	HARDY NORTH	Distrib. Unattended	161.00	13.80	
17	HARRISBURG	Distrib. Unattended	161.00	13.80	
18	HARRISON EAST	Distrib. Unattended	161.00	13.80	
19	HARRISON WEST	Distrib. Unattended	161.00	13.80	
20	HASKELL	Distrib. Unattended	115.00	13.80	
21	HAYS CITY	Distrib. Unattended	115.00	13.80	
22	HAZEN	Distrib. Unattended	115.00	13.80	
23	HEBER SPRINGS INDUSTRIAL	Distrib. Unattended	161.00	13.80	
24	HEBER SPRINGS SOUTH	Distrib. Unattended	161.00	13.80	
25	HELENA CENTRAL	Distrib. Unattended	115.00	13.80	
26	HELENA SOUTH	Distrib. Unattended	115.00	13.80	
27	HENSLEY	Distrib. Unattended	115.00	13.80	
28	HERMITAGE (APL)	Distrib. Unattended	115.00	13.80	
29	HIGHLAND (APL)	Distrib. Unattended	161.00	13.80	
30	HIGHWAY #7	Distrib. Unattended	34.50	13.80	
31	HILO	Distrib. Unattended	115.00	13.80	
32	HUGHES	Distrib. Unattended	161.00	13.80	
33	HUTTIG	Distrib. Unattended	115.00	13.80	
34	IMBODEN	Distrib. Unattended	69.00	34.50	
35	IMBODEN JUNCTION	Distrib. Unattended	34.50	12.40	
36	INDEPENDENCE-ISES-SWITCHYARD	Distrib. Unattended	161.00	13.80	
37	JACKSONVILLE NORTH	Distrib. Unattended	115.00	13.80	
38	JACKSONVILLE SOUTH	Distrib. Unattended	115.00	13.80	
39	JIM HILL	Distrib. Unattended	115.00	34.50	
40	JONESBORO (APL)	Distrib. Unattended	161.00	13.80	

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	KERLIN	Distrib. Unattended	115.00	13.80	
2	KINGSLAND	Distrib. Unattended	115.00	13.80	
3	KUHN ROAD	Distrib. Unattended	161.00	13.80	
4	L.R. 145TH ST	Distrib. Unattended	115.00	13.80	
5	L.R. 23RD & SPRING	Distrib. Unattended	115.00	13.80	
6	L.R. 8TH & WOODROW	Distrib. Unattended	115.00	13.80	
7	L.R. ALEXANDER	Distrib. Unattended	115.00	13.80	
8	L.R. ARCH ST.	Distrib. Unattended	115.00	13.80	
9	L.R. BOYLE PARK	Distrib. Unattended	115.00	13.80	
10	L.R. BRINGLE	Distrib. Unattended	161.00	13.80	
11	L.R. CAMMACK	Distrib. Unattended	115.00	13.80	
12	L.R. CHICOT	Distrib. Unattended	115.00	13.80	
13	L.R. EAST	Distrib. Unattended	115.00	13.80	
14	L.R. FOURCHE	Distrib. Unattended	115.00	13.80	
15	L.R. GAINES	Distrib. Unattended	115.00	13.80	
16	L.R. GARLAND	Distrib. Unattended	115.00	13.80	
17	L.R. HINDMAN	Distrib. Unattended	115.00	13.80	
18	L.R. INDUSTRIAL	Distrib. Unattended	115.00	13.80	
19	L.R. KANIS RD	Distrib. Unattended	115.00	13.80	
20	L.R. MANN	Distrib. Unattended	115.00	13.80	
21	L.R. PINNACLE	Distrib. Unattended	115.00	13.80	
22	L.R. PORT	Distrib. Unattended	115.00	13.80	
23	L.R. ROCK CREEK	Distrib. Unattended	115.00	13.80	
24	L.R. ROLAND ROAD	Distrib. Unattended	115.00	13.80	
25	L.R. SOUTH	Distrib. Unattended	115.00	13.80	
26	L.R. WALTON HEIGHTS	Distrib. Unattended	115.00	13.80	
27	L.R. WEST	Distrib. Unattended	115.00	13.80	
28	L.R. WEST MARKHAM	Distrib. Unattended	115.00	13.80	
29	LAKE CHICOT PUMP STA	Distrib. Unattended	115.00	4.80	
30	LAKE CONWAY	Distrib. Unattended	115.00	13.80	
31	LAKE VILLAGE BAGBY	Distrib. Unattended	115.00	13.80	
32	LAKESWOOD (NLR)	Distrib. Unattended	115.00	13.80	
33	LAMARTINE	Distrib. Unattended	115.00	13.80	
34	LAWSON ROAD	Distrib. Unattended	115.00	13.80	
35	LEACHVILLE	Distrib. Unattended	34.50	12.40	
36	LEPANTO	Distrib. Unattended	161.00	13.80	
37	LEWISVILLE	Distrib. Unattended	115.00	13.80	
38	LONDON	Distrib. Unattended	161.00	13.80	
39	LONOKE EAST	Distrib. Unattended	115.00	13.80	
40	LUNSFORD	Distrib. Unattended	69.00	13.80	

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	MABELVALE EHV	Distrib. Unattended	115.00	13.80	
2	MACEDONIA	Distrib. Unattended	115.00	13.80	
3	MAGNOLIA DOW	Distrib. Unattended	115.00	13.80	
4	MAGNOLIA EAST	Distrib. Unattended	115.00	13.80	
5	MAGNOLIA SOUTH	Distrib. Unattended	115.00	13.80	
6	MAGNOLIA STEEL	Distrib. Unattended	115.00	13.80	
7	MAGNOLIA WEST	Distrib. Unattended	115.00	13.80	
8	MALVERN NORTH	Distrib. Unattended	115.00	13.80	
9	MALVERN SOUTH	Distrib. Unattended	115.00	13.80	
10	MANILA	Distrib. Unattended	34.50	12.40	
11	MANSON 34.5	Distrib. Unattended	34.50	2.40	
12	MARIANNA	Distrib. Unattended	115.00	13.80	
13	MARION	Distrib. Unattended	161.00	13.80	
14	MARKED TREE	Distrib. Unattended	161.00	13.80	
15	MARMADUKE	Distrib. Unattended	34.50	12.40	
16	MARMADUKE ARI	Distrib. Unattended	34.50	12.40	
17	MARMADUKE RAIL 161KV	Distrib. Unattended	161.00	34.50	
18	MARSHALL	Distrib. Unattended	161.00	13.80	
19	MARVELL	Distrib. Unattended	115.00	13.80	
20	MAUMELLE EAST	Distrib. Unattended	115.00	13.80	
21	MCALMONT	Distrib. Unattended	115.00	13.80	
22	MCCRORY	Distrib. Unattended	161.00	13.80	
23	MCGEHEE	Distrib. Unattended	115.00	13.80	
24	MCNEIL EHV	Distrib. Unattended	115.00	13.80	
25	MELBOURNE	Distrib. Unattended	161.00	13.80	
26	MONETTE	Distrib. Unattended	34.50	12.40	
27	MONETTE JUNCTION	Distrib. Unattended	161.00	34.50	
28	MONTICELLO EAST	Distrib. Unattended	115.00	13.80	
29	MONTICELLO SOUTH	Distrib. Unattended	115.00	13.80	
30	MONTROSE	Distrib. Unattended	115.00	13.80	
31	MOOREFIELD	Distrib. Unattended	161.00	13.80	
32	MORELAND	Distrib. Unattended	161.00	13.80	
33	MORGAN	Distrib. Unattended	115.00	13.80	
34	MORO	Distrib. Unattended	115.00	13.80	
35	MORRILTON EAST	Distrib. Unattended	161.00	13.80	
36	MORRILTON WEST	Distrib. Unattended	161.00	13.80	
37	MOUNT PLEASANT	Distrib. Unattended	161.00	13.80	
38	MOUNTAIN HOME	Distrib. Unattended	161.00	13.80	
39	MOUNTAIN VIEW	Distrib. Unattended	161.00	13.80	
40	MT IDA	Distrib. Unattended	115.00	13.80	

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	MT PINE NORTH	Distrib. Unattended	115.00	13.80	
2	MT PINE SOUTH	Distrib. Unattended	115.00	13.80	
3	N.L.R. DIXIE	Distrib. Unattended	115.00	13.80	
4	N.L.R. LEVY	Distrib. Unattended	115.00	13.80	
5	N.L.R. MCCAIN	Distrib. Unattended	115.00	13.80	
6	N.L.R. WESTGATE	Distrib. Unattended	115.00	13.80	
7	NEWARK	Distrib. Unattended	161.00	13.80	
8	NEWPORT	Distrib. Unattended	161.00	13.80	
9	NEWPORT AB	Distrib. Unattended	161.00	13.80	
10	NEWPORT IND	Distrib. Unattended	161.00	13.80	
11	OLA	Distrib. Unattended	115.00	13.80	
12	OMAHA	Distrib. Unattended	161.00	13.80	
13	OSCEOLA	Distrib. Unattended	161.00	13.80	
14	OSCEOLA INDUSTRIAL	Distrib. Unattended	161.00	13.80	
15	OSCEOLA NORTH	Distrib. Unattended	161.00	13.80	
16	P.B. 34TH & MAIN	Distrib. Unattended	115.00	13.80	
17	P.B. ARSENAL D	Distrib. Unattended	115.00	13.80	
18	P.B. DIERKS	Distrib. Unattended	115.00	13.80	
19	P.B. EAST	Distrib. Unattended	115.00	13.80	
20	P.B. INDUSTRIAL	Distrib. Unattended	115.00	13.80	
21	P.B. MCCAMANT	Distrib. Unattended	115.00	13.80	
22	P.B. PORT	Distrib. Unattended	115.00	13.80	
23	P.B. SOUTH	Distrib. Unattended	115.00	13.80	
24	P.B. WATSON CHAPEL	Distrib. Unattended	115.00	13.80	
25	P.B. WEST	Distrib. Unattended	115.00	13.80	
26	P.B. WHITEHALL	Distrib. Unattended	115.00	13.80	
27	PANGBURN	Distrib. Unattended	161.00	13.80	
28	PARAGOULD	Distrib. Unattended	115.00	12.40	
29	PARKIN	Distrib. Unattended	161.00	13.80	
30	POCAHONTAS NORTH	Distrib. Unattended	161.00	12.40	
31	POCAHONTAS SOUTH	Distrib. Unattended	34.50	12.40	
32	PORTIA	Distrib. Unattended	34.50	2.40	
33	POYEN	Distrib. Unattended	115.00	13.80	
34	PRESCOTT	Distrib. Unattended	115.00	13.80	
35	PROMISED LAND	Distrib. Unattended	34.50	12.40	
36	QUITMAN	Distrib. Unattended	161.00	13.80	
37	RECTOR	Distrib. Unattended	161.00	12.40	
38	REYNO	Distrib. Unattended	34.50	4.80	
39	RICHWOOD	Distrib. Unattended	115.00	13.80	
40	RISON	Distrib. Unattended	115.00	13.80	

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	RITCHIE SES PLANT	Distrib. Unattended	230.00	13.80	
2	ROHWER	Distrib. Unattended	115.00	13.80	
3	RUSSELLVILLE EAST	Distrib. Unattended	161.00	13.80	
4	RUSSELLVILLE NORTH	Distrib. Unattended	161.00	13.80	
5	RUSSELLVILLE SOUTH	Distrib. Unattended	161.00	13.80	
6	RUTHERFORD	Distrib. Unattended	161.00	13.80	
7	SC LITTLE ROCK	Distrib. Unattended	34.50	12.40	
8	SEARCY PRICE	Distrib. Unattended	115.00	13.80	
9	SEARCY SOUTH	Distrib. Unattended	161.00	13.80	
10	SHERIDAN	Distrib. Unattended	115.00	13.80	
11	SHERRILL	Distrib. Unattended	115.00	13.80	
12	SHERWOOD	Distrib. Unattended	115.00	13.80	
13	SHOFFNER	Distrib. Unattended	161.00	13.80	
14	SHULER	Distrib. Unattended	115.00	13.80	
15	SMACKOVER	Distrib. Unattended	115.00	13.80	
16	SMACKOVER INDUSTRIAL	Distrib. Unattended	115.00	13.80	
17	SOUTH LEAD HILL	Distrib. Unattended	161.00	34.50	
18	SOUTHSIDE	Distrib. Unattended	161.00	13.80	
19	ST. FRANCIS	Distrib. Unattended	34.50	2.40	
20	ST. JOE	Distrib. Unattended	161.00	13.80	
21	ST. VINCENT	Distrib. Unattended	161.00	13.80	
22	STEPHENS	Distrib. Unattended	115.00	13.80	
23	STRAWBERRY	Distrib. Unattended	13.80	2.40	
24	STRONG	Distrib. Unattended	115.00	13.80	
25	STUTTGART INDUSTRIAL	Distrib. Unattended	115.00	13.80	
26	STUTTGART NORTH	Distrib. Unattended	115.00	13.80	
27	STUTTGART RICUSKEY	Distrib. Unattended	115.00	13.80	
28	SUMMIT	Distrib. Unattended	161.00	13.80	
29	SWIFTON	Distrib. Unattended	161.00	13.80	
30	TAYLOR	Distrib. Unattended	115.00	13.80	
31	THAYER NORTH	Distrib. Unattended	69.00	4.80	
32	TRUMANN	Distrib. Unattended	161.00	13.80	
33	TWIST	Distrib. Unattended	161.00	13.80	
34	ULM	Distrib. Unattended	115.00	13.80	
35	VARNER	Distrib. Unattended	115.00	13.80	
36	VILONIA	Distrib. Unattended	161.00	13.80	
37	WABBASEKA	Distrib. Unattended	115.00	13.80	
38	WALCOTT	Distrib. Unattended	34.50	12.40	
39	WALNUT RIDGE NORTH	Distrib. Unattended	34.50	12.40	
40	WALNUT RIDGE PLANT	Distrib. Unattended	34.50	12.40	

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	WALNUT RIDGE W/161	Distrib. Unattended	161.00	12.40	
2	WARREN EAST	Distrib. Unattended	115.00	13.80	
3	WARREN WEST	Distrib. Unattended	115.00	13.80	
4	WEST HELENA	Distrib. Unattended	115.00	13.80	
5	WEST MEMPHIS DOVER	Distrib. Unattended	161.00	13.80	
6	WEST MEMPHIS GATEWAY	Distrib. Unattended	161.00	13.80	
7	WEST MEMPHIS LEHI	Distrib. Unattended	161.00	13.80	
8	WHELEN SPRINGS	Distrib. Unattended	34.50	12.40	
9	WHITE BLUFF EHV	Distrib. Unattended	115.00	13.80	
10	WILMAR	Distrib. Unattended	115.00	13.80	
11	WILMOT	Distrib. Unattended	34.50	13.80	
12	WILSON	Distrib. Unattended	161.00	13.80	
13	WOODWARD	Distrib. Unattended	115.00	13.80	
14	WYNNE CITY 4160	Distrib. Unattended	13.80	4.80	
15	WYNNE INDUSTRIAL	Distrib. Unattended	161.00	13.80	
16	WYNNE SOUTH	Distrib. Unattended	161.00	13.80	
17	ANO SWITCHYARD	Trans Unattended	500.00	161.00	
18	BALD KNOB-TEXAS EASTERN T.C. P.S. #6 SS	Trans Unattended	161.00	115.00	
19	BENTON WEST	Trans Unattended	161.00	161.00	
20	BRINKLEY EAST	Trans Unattended	230.00	115.00	
21	CONWAY WEST	Trans Unattended	161.00	115.00	
22	DANVILLE (APL)	Trans Unattended	161.00	115.00	
23	DATTO	Trans Unattended	161.00	115.00	
24	DELL EHV	Trans Unattended	500.00	161.00	
25	EL DORADO EHV	Trans Unattended	500.00	115.00	
26	H.S. EHV	Trans Unattended	500.00	115.00	
27	INDEPENDENCE-ISES	Trans Unattended	500.00	161.00	
28	JIM HILL	Trans Unattended	161.00	115.00	
29	L.R. PINNACLE	Trans Unattended	161.00	115.00	
30	LAKE VILLAGE BAGBY	Trans Unattended	230.00	115.00	
31	MABELVALE EHV	Trans Unattended	500.00	115.00	
32	MAYFLOWER EHV	Trans Unattended	500.00	115.00	
33	MCNEIL EHV	Trans Unattended	500.00	115.00	
34	MOSES SES	Trans. Unattended	161.00	115.00	
35	MURFREESBORO SOUTH	Trans Unattended	138.00	115.00	
36	PARAGOULD	Trans Unattended	161.00	115.00	
37	PLEASANT HILL	Trans Unattended	500.00	161.00	
38	RITCHIE SES SWITCHYARD	Trans Unattended	230.00	115.00	
39	SEARCY PRICE	Trans Unattended	161.00	115.00	
40	STUTTGART RICUSKEY	Trans Unattended	230.00	115.00	

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	SYLVAN HILLS	Trans Unattended	161.00	115.00	
2	THAYER SOUTH	Trans Unattended	161.00	69.00	
3	WALNUT RIDGE W/161	Trans Unattended	161.00	115.00	
4	WATER VALLEY	Trans Unattended	161.00	69.00	
5	WEST MEMPHIS EHV	Trans Unattended	500.00	161.00	
6	WHITE BLUFF EHV	Trans Unattended	500.00	115.00	
7	WOODWARD	Trans Unattended	230.00	115.00	
8	WRIGHTSVILLE	Trans Unattended	500.00	115.00	
9	Total Capacity		49076.70	8520.50	
10					
11	Distribution Unattended 336				
12	Transmission Unattended 32				
13					
14	LEASED SUBSTATIONS				
15	MARKMAN FERRY - MARKMAN FERRY, OK	Trans. Unattended	161.00	115.00	
16	ARKLAHOMA "A" - JONES MILL, AR	Trans. Unattended	115.00	13.80	
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (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 (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
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
40	1					15
11	1					16
83	2					17
84	2					18
100	2					19
37	1					20
15	2					21
7	1	1				22
	1					23
13	1					24
33	1					25
67	2					26
64	2					27
34	1					28
7	1					29
7	1					30
22	1					31
67	2					32
13	4					33
6	1					34
2	3					35
20	1					36
13	1					37
7	1					38
25	1					39
6	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
63	3					1
63	2					2
50	2					3
63	2					4
30	1					5
20	1					6
20	1					7
20	1					8
20	1					9
50	1					10
13	1					11
53	2					12
34	1					13
13	1					14
13	1					15
25	2					16
20	1					17
25	1					18
50	1					19
20	1					20
20	1					21
30	2					22
33	1					23
42	2					24
22	1					25
33	1					26
6	1					27
41	2					28
13	1					29
5	1					30
42	2					31
22	1					32
3	1					33
20	1					34
30	1					35
30	1					36
1	3					37
7	1					38
7	1					39
23	2					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
50	1					1
5	1					2
13	1					3
34	1					4
20	1					5
30	1					6
33	1					7
67	2					8
20	1					9
64	2					10
54	2					11
34	1					12
13	2					13
57	3					14
5	1					15
33	1					16
20	1					17
63	2					18
97	3					19
40	2					20
16	1					21
20	1					22
33	1					23
22	1					24
20	1					25
20	1					26
10	1					27
7	1					28
30	1					29
13	1					30
5	1					31
22	1					32
13	1					33
8	1					34
4	3					35
20	1					36
89	2					37
30	1					38
33	1	1				39
22	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
33	2					1
3	1					2
33	1					3
20	1					4
34	1					5
100	2					6
63	2					7
30	1					8
63	2					9
3	1					10
34	1					11
64	2					12
67	2					13
34	1					14
100	2					15
112	2					16
34	1					17
80	2					18
66	2					19
20	1					20
33	1					21
67	2					22
67	2					23
13	1					24
55	2					25
83	2					26
100	2					27
162	3					28
60	2					29
37	1					30
34	1					31
33	1					32
23	2					33
50	1					34
13	1					35
22	1					36
22	1					37
10	1					38
30	1					39
11	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
50	1	4				1
33	1					2
13	1					3
33	1					4
33	1					5
13	1					6
34	1					7
30	1					8
47	2					9
11	1					10
2	3					11
20	1					12
47	2					13
22	1					14
5	1	4				15
11	1					16
33	1					17
20	1					18
12	2					19
67	2					20
67	2					21
20	1					22
30	1					23
20	1					24
22	1					25
5	1					26
75	2					27
34	1					28
30	1					29
47	2					30
46	2					31
20	1					32
63	2					33
7	1					34
34	1					35
30	1					36
10	1					37
56	2					38
42	2					39
42	2					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
20	1					1
33	1					2
50	1	1				3
83	2					4
33	1					5
64	2					6
10	1					7
34	1					8
22	1					9
92	3					10
53	3					11
35	5					12
44	2					13
30	1					14
33	1					15
30	1					16
15	2					17
34	1					18
60	2					19
58	2					20
64	2					21
33	1					22
20	1					23
64	2					24
3	1					25
34	1					26
20	1					27
26	4					28
20	1					29
44	2					30
13	1					31
2	1	1				32
26	2	1				33
42	2					34
1	2					35
22	1					36
48	2					37
1	3					38
7	1					39
9	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
375	1					1
46	2					2
100	2					3
83	2					4
80	2					5
67	2					6
2	2	5				7
84	2					8
84	2					9
30	1					10
7	1					11
106	2					12
5	1					13
33	2					14
13	1					15
33	1					16
20	1					17
20	1					18
1	3					19
3	1					20
20	1					21
10	1					22
4	1					23
13	1					24
33	1					25
30	1					26
60	2					27
42	2					28
25	2					29
4	1					30
7	2					31
20	1					32
5	1					33
20	1					34
25	2					35
40	1					36
13	1					37
1	1					38
11	1					39
20	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
72	3					1
25	2					2
20	1					3
34	1					4
34	1					5
30	1					6
56	2					7
3	1					8
45	2					9
7	1					10
20	1					11
20	1					12
33	1	1				13
	1					14
45	2					15
20	1					16
896	4					17
50	1					18
						19
616	3					20
224	1					21
125	1					22
225	1					23
672	3	1				24
1344	6	2				25
1100	2					26
850	2					27
112	1					28
225	1					29
448	1					30
895	6	2				31
1260	3					32
600	3	1				33
165	2					34
150	1					35
125	1					36
800	4					37
180	1					38
225	1					39
448	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
140	1					1
50	1					2
60	3	1				3
50	1					4
450	3	1				5
840	2					6
300	1					7
597	4					8
25178	545	36				9
						10
						11
						12
						13
						14
75	1					15
13	1					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

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

Schedule Page: 426 Line No.: 1 Column: a

These substations are jointly leased from the Arkklahoma Corporation by Entergy Arkansas and other owners of this Corporation beginning December 9, 1947 and automatically renewed annually. Common stock of the Arkklahoma 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.: 7 Column: a

These substations are jointly leased from the Arkklahoma Corporation by Entergy Arkansas and other owners of this Corporation beginning December 9, 1947 and automatically renew annually. Common stock of the Arkklahoma 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
Entergy Arkansas, Inc.

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2015/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				
3	See footnote for schedule details			
4	See footnote for allocation method details			
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				

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

Schedule Page: 429 Line No.: 3 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 Affiliate			
2	Administration	Entergy Operations, Inc.	517000, 524000, 525000, 529000, 532000, 567000, 930200, 931000	1,485,291
3	Corporate Support - General	Entergy Operations, Inc.	107000, 163000, 174200, 253107, 408110, 408122, 408123, 408142, 426300, 426500, 42650T, 4265TX, 517000, 519000, 520000, 524000, 528000, 529000, 530000, 531000, 532000, 920000, 921000, 925000, 930200	3,641,172
4	Finance - Information Technology	Entergy Operations, Inc.	921000, 923000, 935000	262,870
5	Nuclear - Regulated	Entergy Operations, Inc.	107000, 163000, 174104, 174200, 253107, 408110, 426400, 42650T, 4265TX, 517000, 519000, 520000, 524000, 528000, 530000, 531000, 532000, 920000, 921000	112,290,328
6	Nuclear Corporate Support	Entergy Operations, Inc.	107000, 174104, 253107, 408110, 42650T, 4265TX, 517000, 520000, 524000, 528000, 532000, 920000, 925000	4,101,707
7	Nuclear Operations	Entergy Operations, Inc.	107000, 174104, 253107, 408110, 42650T, 4265TX, 517000, 520000, 524000, 528000, 529000, 531000, 532000, 920000	8,951,098
8	System Benefits	Entergy Operations, Inc.	107000, 163000, 174104, 174200, 253107, 42650T, 926000	44,573,380
9	Administration	Entergy Services, Inc.	107000, 184001, 253107, 4031AM, 408110, 421000, 426100, 426400, 426500, 42650T, 4265TX, 431000, 454000, 517000, 520000, 524000, 525000, 532000, 549000, 560000, 568000,	5,062,183

Name of Respondent		This Report is:	Date of Report	Year/Period of Report
Entergy Arkansas, Inc.		(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2015/Q4
FOOTNOTE DATA				
		580000, 589000, 908000, 910000, 920000, 921000, 923000, 925000, 926000, 928000, 930200, 930210, 931000, 935000		
10	Capital Project Excellence Entergy Services, Inc.	107000, 253107, 408110, 42650T, 4265TX, 500000, 506000, 517000, 560000, 568000, 588000, 920000, 921000, 923000, 926000, 930200, 931000		2,333,192
11	Chief Administrative Officer Entergy Services, Inc.	408110, 426100, 426500, 920000, 921000, 923000, 930200		467,618
12	Corporate Entergy Services, Inc.	107000, 163000, 253107, 408110, 42650T, 4265TX, 920000, 921000, 923000		626,940
13	Corporate - Legal Services Entergy Services, Inc.	107000, 152000, 174101, 181CPD, 186080, 253107, 408110, 426100, 426400, 42650T, 4265TX, 506000, 524000, 568000, 920000, 921000, 923000, 926000, 928000, 930200, 931000		8,067,732
14	Corporate - Office of the Chief Executive Officer Entergy Services, Inc.	184001, 408110, 426400, 426500, 920000, 921000, 923000, 925000, 930200, 931000		612,657
15	Corporate - Public Relations Entergy Services, Inc.	107000, 174104, 186080, 253107, 408110, 426100, 426400, 42650T, 4265TX, 517000, 524000, 546000, 908000, 909000, 910000, 913000, 920000, 921000, 923000, 926000, 928000, 930100, 930200, 931000, 935000		3,256,364
16	Corporate Support - General Entergy Services, Inc.	107000, 118001, 152000, 163000, 174101, 174104, 174200, 181CPD, 184001, 1840FS, 1840NC, 184EST, 186080, 228100, 253107, 4031AM, 408110, 408152, 417100, 426100, 426400, 426500, 42650T, 4265TX, 430000, 500000, 506000, 510000, 512000, 513000, 517000, 519000, 520000, 524000, 528000, 529000, 530000, 532000, 535000, 546000, 549000, 551000, 554000, 556000, 557000, 560000, 561100, 561200, 561300, 561500, 561600, 562000, 566000, 568000, 569000, 569100, 570000, 571000, 580000, 581000, 584000, 586000, 587000,		17,360,180
FERC FORM NO. 1 (ED. 12-87) Page 450.2				

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report	
Entergy Arkansas, Inc.		/ /	2015/Q4	
FOOTNOTE DATA				
		588000, 590000, 592000, 593000, 596000, 596100, 598000, 870000, 880000, 901000, 902000, 903001, 903002, 905000, 907000, 908000, 909000, 910000, 912000, 916000, 920000, 921000, 923000, 924000, 925000, 926000, 928000, 930100, 930200, 935000		
17	Customer Service and Operations Support	Entergy Services, Inc.	107000, 174101, 184EST, 253107, 408110, 4265OT, 4265TX, 561500, 580000, 588000, 589000, 590000, 598000, 901000, 902000, 903001, 903002, 905000, 907000, 908000, 910000, 916000, 920000, 921000, 923000, 926000, 928000, 931000, 935000	9,054,845
18	Finance - Finance and Accounting	Entergy Services, Inc.	107000, 163000, 174101, 174104, 181CPD, 184001, 1840FS, 1840NC, 184EST, 186080, 228100, 253107, 408110, 426100, 426400, 4265OT, 4265TX, 506000, 517000, 524000, 561500, 580000, 901000, 903001, 903002, 905000, 908000, 920000, 921000, 923000, 924000, 925000, 926000, 928000, 930100, 930200, 931000, 935000	11,067,778
19	Finance - Information Technology	Entergy Services, Inc.	107000, 163000, 174101, 174200, 184001, 186080, 253107, 408110, 4265OT, 4265TX, 500000, 506000, 514000, 517000, 524000, 525000, 528000, 532000, 539000, 549000, 554000, 560000, 561200, 566000, 567000, 569100, 573000, 580000, 588000, 589000, 598000, 901000, 903001, 908000, 920000, 921000, 923000, 926000, 930200, 931000, 935000	27,694,103
20	Fossil Operations	Entergy Services, Inc.	107000, 152000, 186080, 228100, 253107, 408110, 426500, 4265OT, 4265TX, 500000, 505000, 506000, 507000, 510000, 511000, 512000, 513000, 514000, 535000, 539000, 541000, 546000, 549000, 551000, 553000, 554000, 566000, 920000, 921000, 923000, 926000, 928000, 931000	10,281,021

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Entergy Arkansas, Inc.			2015/Q4

FOOTNOTE DATA

21	Human Resources	Entergy Services, Inc.	107000, 184001, 186080, 253107, 408110, 426100, 42650T, 4265TX, 517000, 524000, 540000, 560000, 580000, 588000, 589000, 920000, 921000, 923000, 926000, 928000, 930100, 930200, 931000, 935000	4,474,904
22	Nuclear Corporate Support	Entergy Services, Inc.	107000, 163000, 174104, 253107, 408110, 426100, 426400, 42650T, 4265TX, 517000, 519000, 520000, 524000, 525000, 528000, 529000, 530000, 532000, 560000, 920000, 921000, 923000, 926000, 930200, 930201	11,113,034
23	Operations and Performance	Entergy Services, Inc.	107000, 174101, 184001, 186080, 253107, 408110, 426500, 42650T, 4265TX, 500000, 506000, 524000, 546000, 549000, 560000, 566000, 580000, 920000, 921000, 923000, 926000, 930200, 931000	2,453,706
24	Regulatory	Entergy Services, Inc.	107000, 174101, 186080, 253107, 408110, 42650T, 4265TX, 580000, 590000, 920000, 921000, 923000, 928000, 930200	330,863
25	Supply Chain	Entergy Services, Inc.	107000, 108230, 163000, 174200, 186080, 253107, 408110, 426100, 42650T, 4265TX, 500000, 506000, 524000, 546000, 560000, 566000, 580000, 586000, 588000, 920000, 921000, 923000, 926000, 930200	3,909,479
26	System Benefits	Entergy Services, Inc.	107000, 152000, 163000, 174101, 174104, 174200, 181CPD, 184001, 1840FS, 1840NC, 184EST, 186080, 228100, 253107, 408110, 426100, 426400, 42650T, 554000, 568000, 920000, 921000, 923000, 926000, 931000	27,587,537
27	System Planning	Entergy Services, Inc.	107000, 152000, 174200, 186080, 253107, 408110, 426400, 42650T, 4265TX, 500000, 506000, 507000, 514000, 556000, 557000, 561200, 5612BA, 566000, 920000, 921000, 923000, 926000, 928000, 930200, 931000	8,160,858
28	Tax And Interest Expense	Entergy Services, Inc.	408122, 408123, 408142, 408152, 408165, 409112,	2,005,838

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.		/ /	2015/Q4
FOOTNOTE DATA			
		409114, 410101, 410120, 411110, 411120, 411430, 419000, 419011, 426300, 431000	
29	Transmission Entergy Services, Inc.	107000, 163000, 174101, 174200, 184001, 184EST, 186080, 228100, 253107, 408110, 426100, 426400, 426500, 4265OT, 4265TX, 546000, 560000, 561100, 561200, 5612BA, 561300, 561500, 561600, 562000, 566000, 567000, 568000, 569000, 570000, 573000, 580000, 582000, 588000, 589000, 590000, 592000, 593000, 903001, 920000, 921000, 923000, 926000, 928000, 930200, 935000	21,656,533
30	Utility Management and Support Services Entergy Services, Inc.	107000, 174101, 174200, 184EST, 253107, 408110, 426100, 426400, 426500, 4265OT, 4265TX, 517000, 560000, 566000, 568000, 580000, 588000, 589000, 590000, 596100, 903001, 907000, 908000, 909000, 910000, 911000, 912000, 913000, 916000, 920000, 921000, 923000, 926000, 928000, 930100, 930200, 931000, 935000	10,601,525
31	Utility Support - Distribution Entergy Services, Inc.	107000, 174101, 184001, 1840FS, 1840NC, 184EST, 228400, 253107, 408110, 426400, 4265OT, 4265TX, 517000, 560000, 566000, 580000, 588000, 589000, 590000, 591000, 596000, 596100, 598000, 903001, 920000, 921000, 923000, 925000, 926000, 928000, 930200	3,069,256
32	Inventory Transfers of Materials and Supplies. Entergy Gulf States-LA L.L.C.	154PAS	270,610
33	Fossil Support - Ouachita Plant Operations and Support. Entergy Louisiana, LLC (Old ELL)	163000, 408110, 546000, 548000, 549000, 551000, 553000, 920000, 926000	2,036,093
34	Inventory Transfers of Materials and Supplies. Entergy Louisiana, LLC (Old ELL)	154PAS	641,476
35	Fossil Support - Ouachita Plant Operations and Entergy Louisiana, LLC NEW	163000, 408110, 546000, 548000, 549000, 553000, 920000, 926000	807,434
FERC FORM NO. 1 (ED. 12-87)		Page 450.5	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Entergy Arkansas, Inc.		//	2015/Q4
FOOTNOTE DATA			
	Support.		
36	Storm Distribution Support - Repairs, Coordination and Management of Storm Restoration.	Entergy Texas, Inc. 174101, 408110, 920000, 926000	364,921
37 Non-power Goods or Services Provided for Affiliate			
38	Distribution Support - Installation of meters, wires, and lighting. Including maintenance and safety.	Entergy Louisiana, LLC (Old ELL) 107000, 408110, 593000, 926000	1,491,754
39	Distribution Support - Truck stock lighting and materials installation.	Entergy Louisiana, LLC (Old ELL) 107000, 580000	678,175
40	Inventory Transfers of Materials and Supplies.	Entergy Louisiana, LLC (Old ELL) 154PAS, 163000	2,708,079
41	Distribution Support - Installation of meters, wires, and lighting. Including maintenance and safety.	Entergy Louisiana, LLC NEW 107000, 408110, 593000, 926000	412,491
42	Inventory Transfers of Materials and Supplies.	Entergy Louisiana, LLC NEW 154PAS	688,067
43	Customer Service Support - Provide Billing and Account Maintenance.	Entergy Mississippi, Inc. 408110, 903002, 926000	345,825
44	Distribution Support - Installation of meters, wires, and lighting. Including maintenance and safety.	Entergy Mississippi, Inc. 107000, 408110, 593000, 926000	589,558
45	Distribution Support - Truck stock lighting and materials installation.	Entergy Mississippi, Inc. 107000, 580000	342,189

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			

FOOTNOTE DATA

46	Inventory Transfers of Materials and Supplies.	Entergy Mississippi, Inc.	154PAS, 163000	1,258,835
47	Inventory Transfers of Materials and Supplies.	Entergy Texas, Inc.	154PAS	330,616
48	Storm Distribution Support - Repairs, Coordination and Management of Storm Restoration.	Entergy Texas, Inc.	174101, 408110, 920000, 926000	435,453

Schedule Page: 429 Line No.: 4 Column: a

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.

Nuclear Corporate Support	EMPLOEOI, PWRSANWF, SPLEOIPL, SPLEUNIT
Nuclear Operations	EMPLOEOI, SPLEOIPL
System Benefits	EMPLOEOI, PWRSANWF, SPLEOIPL, SPLEUNIT
Entergy Services, Inc.	
Administration	APPSUPAL, ASSTSALL, ASSTSREG, BNKACCTA, CAPACCGT, CAPAOPCO, CUSEOPCO, CUSTEGOP, EMPLOREG, EMPLOYAL, GENLEDAL, INSPREAL, ITSPENDA, LBRBILAL, LBRCOMUN, LBRCORPT, LBRLEGAL, LBRSUPCN, LVLSVCAL, PKLOADAL, SCPSPALL, SNUCSITE, SQFTALLC, TELXGENS, TRASUBOP, TRSBLNOP
Capital Project Excellence	ASSTSALL, ASSTSREG, CAPAOPCO, CAPSTEAM, CUSEOPCO, CUSTEGOP, EMPLOYAL, GENLEDAL, ITSPENDA, LBRBILAL, LBRCORPT, NETPPEAL, PKLOADAL, SCDSPALL, SCPSPALL, SNUCUNIT, TRALINOP, TRANSPND, TRSBLNOP
Chief Administrative Officer	ASSTSALL, EMPLPRES
Corporate	ASSTSALL, ASSTSREG, CAPAOPCO, EMPLOREG, EMPLOYAL, ITSPENDA, LBRCORPT, PCNUMALL, SCPSPALL
Corporate - Legal Services	APPSUPAL, APTRNALL, ASSTSALL, ASSTSREG, CAPAOPCO, COALARGS, CUSEOPCO, CUSTEGOP, EMPLOFOS, EMPLOREG, EMPLOYAL, EMPLTRAN, GENLEDAL, ITSPENDA, LBRADMIN, LBRBILAL, LBRCORPT, LBRFINAN, LBRINFOR, LBRLEGAL, LBRUTOPN, LVLSVCAL, OWNISFI, PKLOADAL, PLOSSAL, RECDMGNT, SNUCSITE, SNUCSITX, SNUCUNIT, SQFTALLC, TRSBLNOP, UNPWROWN
Corporate - Office of the Chief Executive Officer	ASSTSALL, EMPLOYAL, LBRCORPT, LVLSVCAL, SNUCSITE
Corporate - Public Relations	ASSTSALL, CAPAOPCO, CUSEOPCO, CUSTEGOP, EMPLOREG, EMPLOYAL, LBRCOMUN, LBRCORPT, LBRFDPOL, LBRLEGAL, LVLSVCAL, MACCTALL, PKLOADAL, SNUCSITE, SQFTALLC, TRASUBOP, TRSBLNOP, UNPWROWN
Corporate Support - General	APPSMVSX, APPSUNIX, APPSUPAL, APPSWINT, APTRNALL, ARTRNALL, ASSTSALL, ASSTSREG, BNKACCTA, CAPACALL, CAPACCGT, CAPANWES, CAPAOPCO, CAPSFUEL, CAPSTEAM,

Name of Respondent		This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.			/ /	

FOOTNOTE DATA				
---------------	--	--	--	--

	CAPXCOPC, COALARGS, COMCLAIM, CUSEGALL, CUSEGXTX, CUSEOPCO, CUSTCALL, CUSTEGOP, CUSTEXTX, DSTLNALL, EMPLFRAN, EMPLOCSS, EMPLOFOS, EMPLOREG, EMPLOYAL, EMPLPRES, EMPLTRAN, EMPLUTOP, FIBRMREG, GENLDREG, GENLEDAL, INSPREAL, ITSPENDA, LBRADMIN, LBRBILAL, LBRBLFOS, LBRBLNUC, LBRBLSPO, LBRCOMUN, LBRCRPUT, LBRFDPOL, LBRFINAN, LBRINFOR, LBRLEGAL, LBRSUPCN, LBRUTOPN, LVLSVCAL, MACCTALL, MACCTNLA, NETPPEAL, OWNISFI, PCNUMALL, PCNUMXNR, PKLOADAL, PLLOSSAL, PRCHKALL, PWRSNUCA, RADIOALL, RECDMGNT, SCDSPALL, SCFSPALL, SCMATRAN, SCMATXNU, SCPSPALL, SCPSPXNC, SCTDSPAL, SCTSPALL, SECT263A, SNUCSITE, SNUCSITX, SNUCUNIT, SNUX7877, SQFTALLC, TELPHALL, TRALINOP, TRANSPND, TRASUBOP, TRSBLNOP, TRSBLNXN, UNPWROWN, VEHCLFOS, VEHCLNUC, VEHCLUSG				
Customer Service and Operations Support	ASSTSREG, CAPACALL, CAPAOPCO, CUSEGXTX, CUSEOPCO, CUSTCALL, CUSTEGOP, CUSTEXTX, CUSTOEM, DSTLNALL, EMPLOCSS, EMPLOYAL, EMPLUTOP, LBRCORPT, LBRSUPCN, LBRUTOPN, MACCTALL, SQFTALLC, TRSBLNOP				
Finance - Finance and Accounting	APPSUPAL, APTRNALL, ARTRNALL, ASSTSALL, ASSTSREG, BNKACCTA, CAPAOPCO, COALARGS, CUSEGALL, CUSEGXTX, CUSEOPCO, CUSTEGOP, EMPLOREG, EMPLOYAL, EMPLPRES, EMPLUTOP, GENLDREG, GENLEDAL, INSPREAL, ITSPENDA, LBRBILAL, LBRCOMUN, LBRCORPT, LBRFDPOL, LBRFINAN, LBRINFOR, LBRLEGAL, LBRSUPCN, LBRUTOPN, LVLSVCAL, MACCTALL, NETPPEAL, OWNISFI, PKLOADAL, PLLOSSAL, PRCHKALL, SCMATRAN, SCPSPALL, SECT263A, SNUCSITE, SNUCUNIT, SNUX7877, SQFTALLC, TELPHALL, TELXGENS, TRALINOP, TRANSPND, TRSBLNOP, UNPWROWN, VEHCLFOS, VEHCLNUC, VEHCLUSG				
Finance - Information Technology	APPSMVSX, APPSUNIX, APPSUPAL, APPSWINT, APTRNALL, ARTRNALL, ASSTSALL, ASSTSREG, BNKACCTA, CAPACALL, CAPAOPCO, CUSEGRXT, CUSEGXTX, CUSEOPCO, CUSTCALL, CUSTEGOP, DSTLNALL, EMPLOYAL, EMPLTRAN, FIBRMREG, GENLEDAL, ITSPENDA, LBRBILAL, LBRCORPT, LVLSVCAL, PCNUMALL, PCNUMXNR, PKLOADAL, PLLOSSAL, PRCHKALL, RADIOALL, RECDMGNT, SCDSPALL, SCMATRAN, SCMATXNU, SCPSPALL, SCPSPXNC, SCTDSPAL, SNUCSITE, SNUCUNIT, SQFTALLC, TELPHALL, TELXGENS, TRALINOP, TRANSPND, TRASUBOP, TRSBLNOP, TRSBLNXN, UNPWROWN, VEHCLFOS, VEHCLUSG				
Fossil Operations	ASSTSALL, CAPACGT, CAPAOPCO, CAPSFUEL, CAPSTEAM, CUSTEGOP, EMPLOYAL, LBRBILAL, LBRCORPT, LBRUTOPN, LVLSVCAL, PKLOADAL, SQFTALLC, TELPHALL, UNPWROWN, VEHCLFOS, VEHCLUSG				
Human Resources	ARTRNALL, ASSTSALL, CAPAOPCO, CUSEOPCO, CUSTEGOP, EMPLFRAN, EMPLOCSS, EMPLOFOS, EMPLOREG, EMPLOYAL, EMPLTRAN, EMPXENUC, ITSPENDA, LBRBILAL, LBRCORPT, LVLSVCAL, NETPPEAL, SCPSPALL, SNUCSITE, SQFTALLC, UNPWROWN, VEHCLUSG				
Nuclear Corporate Support	ASSTSALL, ASSTSREG, CAPAOPCO, CUSTEGOP, CUSTEXTX, EMPLOYAL, LBRCORPT, PWRSNUCA, SNUCSITE, SNUCUNIT, TRANSPND				
Operations and Performance	ASSTSALL, CAPAOPCO, CUSEOPCO, CUSTEGOP, EMPLFRAN, EMPLOFOS, EMPLOREG, EMPLOYAL, EMPLTRAN, ITSPENDA, LBRBILAL, LBRCORPT, LBRFDPOL, LVLSVCAL, PKLOADAL, SNUCSITE, SQFTALLC, TRANSPND, TRSBLNOP, UNPWROWN				
Regulatory	ASSTSREG, CUSEOPCO, CUSTEGOP, EMPLOYAL, EMPLUTOP,				

Name of Respondent		This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
Entergy Arkansas, Inc.				
FOOTNOTE DATA				
	LBRUTOPN, PKLOADAL, SQFTALLC, UNPWROWN			
Supply Chain	APTRNALL, ASSTSALL, CAPAOPCO, CUSEOPCO, EMPLOYAL, ITSPENDA, LBRCORPT, LBRLEGAL, LBRSUPCN, NETPPEAL, PWRGNUCA, SCDSPALL, SCFSPALL, SCLDTMLS, SCMATXNU, SCPSPALL, SCPSPXNC, SCTDSPAL, SCTSPALL, SNUCSITE, SNUCUNIT, SQFTALLC, TRANSPND, TRSBLNOP, UNPWROWN			
System Benefits	APPSUPAL, APPSWINT, APTRNALL, ARTRNALL, ASSTSALL, ASSTSREG, BNKACCTA, CAPACALL, CAPACCGT, CAPAOPCO, CAPSFUEL, CAPSTEAM, CAPXCOPC, COALARGS, COMCLAIM, CUSEGALL, CUSEGXTX, CUSEOPCO, CUSTCALL, CUSTGOP, CUSTEXTX, CUSTOEAM, DSTLNALL, EMPLFRAN, EMPLOCSS, EMPLOFOS, EMPLOREG, EMPLOYAL, EMPLTRAN, EMPLUTOP, FIBRMREG, GENLDREG, GENLEDAL, INSPREAL, ITSPENDA, LBRADMIN, LBRBILAL, LBRCOMUN, LBRCORPT, LBRFDPOL, LBRFINAN, LBRINFOR, LBRLEGAL, LBRSUPCN, LBRUTOPN, LVLSVCAL, MACCTALL, MACCTNLA, NETPPEAL, OWNISFI, PCNUMALL, PCNUMXNR, PKLOADAL, PLLOSSAL, PRCHKALL, PWRGNUCA, RADIOALL, RECDMGNT, SCDSPALL, SCFSPALL, SCMATRAN, SCMATXNU, SCPSPALL, SCPSPXNC, SCTDSPAL, SCTSPALL, SECT263A, SNUCSITE, SNUCSITX, SNUCUNIT, SNUX7877, SQFTALLC, TELPHALL, TRALINOP, TRANSPND, TRASUBOP, TRSBLNOP, TRSBLNXN, UNPWROWN, VEHCLFOS, VEHCLNUC, VEHCLUSG			
System Planning	ASSTSALL, CAPACALL, CAPAOPCO, CAPXCOPC, COALARGS, CUSEOPCO, EMPLOREG, EMPLOYAL, LVLSVCAL, MACCTALL, PKLOADAL, SQFTALLC, UNPWROWN			
Tax And Interest Expense	LBRBILAL, LVLSVCAL, PKLOADAL			
Transmission	APPSUPAL, ASSTSALL, CAPAOPCO, CAPSTEAM, CUSEOPCO, CUSTEGOP, EMPLFRAN, EMPLOREG, EMPLOYAL, EMPLTRAN, EMPLUTOP, ITSPENDA, LBRCORPT, LBRFDPOL, LBRUTOPN, LVLSVCAL, PKLOADAL, SCDSPALL, SCPSPALL, SCTSPALL, SQFTALLC, TELPHALL, TRALINOP, TRANSPND, TRASUBOP, TRSBLNOP, TRSBLNXN, UNPWROWN			
Utility Management and Support Services	ASSTSALL, ASSTSREG, CAPAOPCO, CAPSTEAM, CUSEOPCO, CUSTEGOP, EMPLFRAN, EMPLOYAL, EMPLPRES, EMPLUTOP, GENLDREG, GENLEDAL, LBRCORPT, LBRFDPOL, LBRLEGAL, LBRUTOPN, LVLSVCAL, MACCTALL, MACCTNLA, NETPPEAL, PKLOADAL, SNUCUNIT, SQFTALLC, TELPHALL, TRASUBOP, TRSBLNOP, UNPWROWN			
Utility Support - Distribution	ASSTSALL, COMCLAIM, CUSEOPCO, CUSTEGOP, EMPLFRAN, EMPLOYAL, EMPLUTOP, GENLEDAL, LBRCORPT, LBRFDPOL, LBRSUPCN, LVLSVCAL, PKLOADAL, PLLOSSAL, SNUCSITE, SQFTALLC, TELPHALL, TELXGENS, TRALINOP, TRANSPND, TRASUBOP, TRSBLNOP, VEHCLALL, VEHCLFOS, VEHCLNUC, VEHCLUSG			

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
PWRSANWF	Pressure Water Reactors Sites	Based on the number of Pressure Water Reactors Plant Sites - ENS
SPLEO IPL	Nuclear South Plant Sites	Based on the number of Nuclear South Plant Sites

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

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 (UNIX)	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 were operating at maximum capability simultaneously
CAPACCGT	System Capacity - EAI, ELL, EGSL, and EMI	Based on the power level, in kilowatts, that could be achieved if all non-nuclear generating units were operating at maximum capability simultaneously (CCGT)
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
CAPSFUEL	System Capacity - EAI, EGSL, and EMI	Based on the power level, in kilowatts, that could be achieved if all non-nuclear generating units were operating at maximum capability simultaneously

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Entergy Arkansas, Inc.		/ /	2015/Q4
FOOTNOTE DATA			
		(SFUEL).	
CAPSTEAM	System Capacity - EAI, ELL, EGSL, EMI, ENOI, and ETI	Based on the power level, in kilowatts, that could be achieved if all non-nuclear generating units were operating at maximum capability simultaneously (STEAM).	
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	
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 Retail Customers - excluding ETI	Based on a 12 month average number of electric and gas retail customers, excluding Texas (ETI)	
CUSEGXTX	Electric & Gas Customers - excluding ETI	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	
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,	
FERC FORM NO. 1 (ED. 12-87)	Page 450.11		

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Entergy Arkansas, Inc.			2015/Q4
FOOTNOTE DATA			
			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
DSTLNALL	Distribution Line Miles		Based on the number of miles of distribution lines
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 - Transmission		Based on the number of full and part time employees within Transmission
EMPLUTOP	Employees - Utility Operations		Based on the number of full and part time employees within Utility Operations
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
LBRADMIN	ESI Labor Billed - Administration		Based on total labor dollars billed to each company by ESI for the Administration function
LBRBILAL	ESI Labor Costs Billed		Based on total labor dollars billed to each company by ESI

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

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
LBRBLSPO	ESI Labor Billed - SPO	Based on total labor dollars billed to each company by ESI for the System Planning & Operations function
LBRCOMUN	ESI Labor Billed - Communications	Based on total labor dollars billed to each company by ESI for the Communications 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
LBRFDPOL	ESI Labor Billed - Federal Policy, Regulatory & Governmental Affairs	Based on total labor dollars billed to each company by ESI for the Federal Policy, Regulatory & Governmental 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
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
NETPPEAL	Net Property, Plant, & Equipment	Based on the net book value of property, plant and equipment, excluding natural gas and nuclear fuel.
OWNISFI	Percentage Ownership - SFI	Based on the percentage ownership of SFI

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

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 Spending - Distribution	Based on Supply Chain Procurement 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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Entergy Arkansas, Inc.		//	2015/Q4
FOOTNOTE DATA			
		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 263A	
SNUCSITE	Nuclear Plant Sites	Based on the number of Nuclear Plant Sites	
SNUCSITX	Nuclear Plant Sites - excluding Palisades	Based on the number of Nuclear Plant Sites -excluding Palisades	
SNUCUNIT	Nuclear Units	Based on the number of Nuclear Units	
SNUX7877	Nuclear Plant Sites - Excluding JAF and IP3	Based on the number of Nuclear Plant Sites - Excluding JAF (78000) and IP3 (77000)	
SQFTALLC	Square Footage - All Companies	Based on square footage within all business units	
TELPBALL	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)	
TRSBLNXN	Transmission Line Miles/Substation (EXCLUDING ENOI)	Based on two components: Transmission Line Miles (30% weighting) and the Number of High Voltage Substations (70% weighting)	
UNPWROWN	Proposed Ownership (EAI, ENOI, & ELL) - Union Power	Based on the proposed ownership percentages of EAI, ENOI, and ELL for Union Power	
VEHCLALL	Number of Vehicles	Based on the number of vehicles owned or leased by each business unit	
VEHCLFOS	Number of Vehicles - Fossil	Based on the number of vehicles 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	
FERC FORM NO. 1 (ED. 12-87)	Page 450.15		

Name of Respondent Entergy Arkansas, Inc.	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4
FOOTNOTE DATA			
		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 excluding Fossil and Nuclear	

INDEX

<u>Schedule</u>	<u>Page No.</u>
Accrued and prepaid taxes	262-263
Accumulated Deferred Income Taxes	234
	272-277
Accumulated provisions for depreciation of	
common utility plant	356
utility plant	219
utility plant (summary)	200-201
Advances	
from associated companies	256-257
Allowances	228-229
Amortization	
miscellaneous	340
of nuclear fuel	202-203
Appropriations of Retained Earnings	118-119
Associated Companies	
advances from	256-257
corporations controlled by respondent	103
control over respondent	102
interest on debt to	256-257
Attestation	i
Balance sheet	
comparative	110-113
notes to	122-123
Bonds	256-257
Capital Stock	251
expense	254
premiums	252
reacquired	251
subscribed	252
Cash flows, statement of	120-121
Changes	
important during year	108-109
Construction	
work in progress - common utility plant	356
work in progress - electric	216
work in progress - other utility departments	200-201
Control	
corporations controlled by respondent	103
over respondent	102
Corporation	
controlled by	103
incorporated	101
CPA, background information on	101
CPA Certification, this report form	i-ii

<u>Schedule</u>	<u>Page No.</u>
Deferred	
credits, other	269
debits, miscellaneous	233
income taxes accumulated - accelerated amortization property	272-273
income taxes accumulated - other property	274-275
income taxes accumulated - other	276-277
income taxes accumulated - pollution control facilities	234
Definitions, this report form	iii
Depreciation and amortization	
of common utility plant	356
of electric plant	219
	336-337
Directors	105
Discount - premium on long-term debt	256-257
Distribution of salaries and wages	354-355
Dividend appropriations	118-119
Earnings, Retained	118-119
Electric energy account	401
Expenses	
electric operation and maintenance	320-323
electric operation and maintenance, summary	323
unamortized debt	256
Extraordinary property losses	230
Filing requirements, this report form	
General information	101
Instructions for filing the FERC Form 1	i-iv
Generating plant statistics	
hydroelectric (large)	406-407
pumped storage (large)	408-409
small plants	410-411
steam-electric (large)	402-403
Hydro-electric generating plant statistics	406-407
Identification	101
Important changes during year	108-109
Income	
statement of, by departments	114-117
statement of, for the year (see also revenues)	114-117
deductions, miscellaneous amortization	340
deductions, other income deduction	340
deductions, other interest charges	340
Incorporation information	101

<u>Schedule</u>	<u>Page No.</u>
Interest	
charges, paid on long-term debt, advances, etc	256-257
Investments	
nonutility property	221
subsidiary companies	224-225
Investment tax credits, accumulated deferred	266-267
Law, excerpts applicable to this report form	iv
List of schedules, this report form	2-4
Long-term debt	256-257
Losses-Extraordinary property	230
Materials and supplies	227
Miscellaneous general expenses	335
Notes	
to balance sheet	122-123
to statement of changes in financial position	122-123
to statement of income	122-123
to statement of retained earnings	122-123
Nonutility property	221
Nuclear fuel materials	202-203
Nuclear generating plant, statistics	402-403
Officers and officers' salaries	104
Operating	
expenses-electric	320-323
expenses-electric (summary)	323
Other	
paid-in capital	253
donations received from stockholders	253
gains on resale or cancellation of reacquired capital stock	253
miscellaneous paid-in capital	253
reduction in par or stated value of capital stock	253
regulatory assets	232
regulatory liabilities	278
Peaks, monthly, and output	401
Plant, Common utility	
accumulated provision for depreciation	356
acquisition adjustments	356
allocated to utility departments	356
completed construction not classified	356
construction work in progress	356
expenses	356
held for future use	356
in service	356
leased to others	356
Plant data	336-337
	401-429

<u>Schedule</u>	<u>Page No.</u>
Plant - electric	
accumulated provision for depreciation	219
construction work in progress	216
held for future use	214
in service	204-207
leased to others	213
Plant - utility and accumulated provisions for depreciation	
amortization and depletion (summary)	201
Pollution control facilities, accumulated deferred	
income taxes	234
Power Exchanges	326-327
Premium and discount on long-term debt	256
Premium on capital stock	251
Prepaid taxes	262-263
Property - losses, extraordinary	230
Pumped storage generating plant statistics	408-409
Purchased power (including power exchanges)	326-327
Reacquired capital stock	250
Reacquired long-term debt	256-257
Receivers' certificates	256-257
Reconciliation of reported net income with taxable income	
from Federal income taxes	261
Regulatory commission expenses deferred	233
Regulatory commission expenses for year	350-351
Research, development and demonstration activities	352-353
Retained Earnings	
amortization reserve Federal	119
appropriated	118-119
statement of, for the year	118-119
unappropriated	118-119
Revenues - electric operating	300-301
Salaries and wages	
directors fees	105
distribution of	354-355
officers'	104
Sales of electricity by rate schedules	304
Sales - for resale	310-311
Salvage - nuclear fuel	202-203
Schedules, this report form	2-4
Securities	
exchange registration	250-251
Statement of Cash Flows	120-121
Statement of income for the year	114-117
Statement of retained earnings for the year	118-119
Steam-electric generating plant statistics	402-403
Substations	426
Supplies - materials and	227

<u>Schedule</u>	<u>Page No.</u>
Taxes	
accrued and prepaid	262-263
charged during year	262-263
on income, deferred and accumulated	234
	272-277
reconciliation of net income with taxable income for	261
Transformers, line - electric	429
Transmission	
lines added during year	424-425
lines statistics	422-423
of electricity for others	328-330
of electricity by others	332
Unamortized	
debt discount	256-257
debt expense	256-257
premium on debt	256-257
Unrecovered Plant and Regulatory Study Costs	230