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

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

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

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
The Empire District Electric Company	End of 2018/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/forms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

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

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

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

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

The CPA Certification Statement should:

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

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

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

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

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

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

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

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

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.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 1,168 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 168 hours per response.

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

General Penalties

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent The Empire District Electric Company	02 Year/Period of Report End of 2018/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)* 602 S Joplin Ave Joplin MO 64801	
05 Name of Contact Person Tisha A. Sanderson	06 Title of Contact Person Vice-Pres of Finance & Admin
07 Address of Contact Person *(Street, City, State, Zip Code)* 602 S Joplin Ave Joplin MO 64801	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(417) 625-5100	(1) ☐ An Original (2) ☒ A Resubmission	05/13/2019

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Tisha A. Sanderson 02 Title Vice-President-Finance & Admin	Tisha A. Sanderson	05/13/2019

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/13/2019	End of 2018/Q4

LIST OF SCHEDULES (Electric Utility)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/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)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
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	
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	
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	
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	
66	Generating Plant Statistics Pages	410-411	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/13/2019	End of 2018/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/13/2019	End of 2018/Q4

GENERAL INFORMATION

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

Tisha A. Sanderson
Vice-President of Finance and Administration
602 S Joplin Ave
Joplin MO 64801

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.

Kansas - October 16, 1909

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.

Not Applicable

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
Kansas - Electric
Missouri - Electric, Gas and Water
Oklahoma - Electric

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

CONTROL OVER RESPONDENT

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

Liberty Utilities (Central) Company owns 100% of the outstanding shares of respondent.

Liberty Utilities (Central) Company is a direct subsidiary of Liberty Utilities Company and an indirect subsidiary of Algonquin Power & Utilities Corporation.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Empire District Industries Inc	Fiber Serv & Misc Elec Serv	100	
2	Empire Dist Gas Co	Gas Company	100	
3	EDE Property Transfer Corp (Inactive)		100	
4	Empire Dist Electric Arkansas LLC (Inactive)	Electric Company	100	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President	David Swain	261,855
2			
3	Vice President - Finance & Administration	Rob Sager	175,011
4			
5	Vice President - Finance & Administration	Tisha A. Sanderson	176,000
6			
7	Vice President - Customer Experience	Brent Baker	220,002
8			
9	Vice President - Operations-Electric	Blake Mertens	218,421
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11	Vice President - Operations-Gas	Michael Beatty	196,746
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Schedule Page: 104 Line No.: 3 Column: b

Rob Sager is no longer with the company as of February 2018. Tisha A. Sanderson replaced his position in April 2018.

Schedule Page: 104 Line No.: 16 Column: a

The salaries are the officers base salaries at year end.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/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	Nicole Brown	Joplin, Missouri
2		
3	Kenneth Allen	Fayetteville, Arkansas
4		
5	John Thompson	Jackson, Missouri
6		
7	Ian Robertson	Oakville, Ontario, Canada
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9	David Pasieka	Oakville, Ontario, Canada
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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

Does the respondent have formula rates?

[X] Yes

[ ] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	GFR Tariff, FERC Elec Tariff (Revised Vol #4)	FERC Dockets #ER10-877', ER12-1039', ER13--681',
2		ER12-483', ER15-229'
3		
4	Attachment H-1 Revised, Transmission Formula Rate	FERC Dockets #ER12-1813', ER14-2882'
5	Template, Revised 3.0.0	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	[X] Yes [ ] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20160115-5687	01/15/2016	ER16-749-000	TFR Informational Filing	Attachment H-1 Revised, Transmission
2					Formula Rate Template, Revised 3.0.0
3	20170117-5329	01/17/2017	ER17-807-000	TFR Informational Filing	Attachment H-1 Revised, Transmission
4					Formula Rate Template, Revised 3.0.0
5	20180116-5295	01/16/2018	ER18-666-000	TFR Informational Filing	Attachment H-1 Revised, Transmission
6					Formula Rate Template, Revised 3.0.0
7	20190115-5330	01/15/2019	ER19-829-000	TFR Informational Filing	Attachment H-1 Revised, Transmission
8					Formula Rate Template, Revised 3.0.0
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Schedule Page: 1061 Line No.: 1 Column: a

Annual informational filings are made for the TFR as shown on this page.

No annual filings are made for the GFR.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
1	112	Comparative Balance Sheet (Bonds-Current Yr)	c	18
2	112	Comparative Balance Sheet (Bonds-Prior Yr)	d	18
3	112	Comp Bal Sheet (Unapp Undist Subearnings-Curr Yr)	c	12
4	112	Comp Bal Sheet (Unapp Undist Subearnings-Prior Yr)	d	12
5	117	Stmt of Inc for the Yr (Interest on LTD-Curr Yr)	c	62
6	205	Totat Prod Plant in Service	g	46
7	207	Totat Electric Plant in Service	g	104
8	219	Accum Prov for Depreciation of Electric Plant	b	20
9	219	Accum Prov for Depreciation of Electric Plant	b	29
10	336	Depreciation Expense of Electric Plant	b	2,4,6,7,8,10,12
11				
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
The Empire District Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/13/2019	End of 2018/Q4

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.

1. **Franchise Renewals**:

The following Electric Franchise Ordinances were renewed in 2018:

MISSOURI

MUNICIPALITY	OLD EXPIRATION DATE	NEW EXPIRATION DATE
Ash Grove	09-08-18	05-07-38
Buffalo	04-12-19	09-10-38
Strafford	04-06-18	03-05-38
Willard	04-12-19	08-13-38

There were no Electric Franchise Ordinances renewed for Arkansas, Kansas, or Oklahoma for the year 2018.

There were no Municipal Electric Service Agreements renewed for Arkansas, Kansas, Missouri and Oklahoma for the year 2018.

2. None

3. None

4. See Note 11 of the "Notes to Consolidated Financial Statements" for discussion regarding windfarm leases.

5. None

6. As of December 31, 2018, Empire District Electric Company had $6 million of commercial paper outstanding. No other new debt or debt guarantees were issued during the 4th quarter of 2018.

7. None

8. None

9. None

10. None

11. Reserved

12. None

13. On March 31, 2019, Mr. Blake Mertens resigned from his position as Central Region Vice-President of Operations - Electric.

14. None

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/13/2019	End of 2018/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	2,886,503,459	2,801,273,069
3	Construction Work in Progress (107)	200-201	45,799,911	31,865,472
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		2,932,303,370	2,833,138,541
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	979,349,137	913,899,347
6	Net Utility Plant (Enter Total of line 4 less 5)		1,952,954,233	1,919,239,194
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
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)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		1,952,954,233	1,919,239,194
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		0	0
19	(Less) Accum. Prov. for Depr. and Amort. (122)		55,138	53,205
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	69,146,334	65,534,517
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	0
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		0	0
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)		69,091,196	65,481,312
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		7,837,553	5,882,771
36	Special Deposits (132-134)		29,465	64,853
37	Working Fund (135)		167,286	213,089
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		44,953,378	46,056,260
41	Other Accounts Receivable (143)		6,440,475	9,990,868
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		380,930	350,000
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		4,614,434	5,014,610
45	Fuel Stock (151)	227	21,690,759	24,111,839
46	Fuel Stock Expenses Undistributed (152)	227	63	3,603
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	35,446,397	31,220,248
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	0	8,266

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	8,399	22,652
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)		8,829,408	9,470,383
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	7,160
60	Rents Receivable (172)		50,131	49,848
61	Accrued Utility Revenues (173)		23,409,088	17,850,464
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		13,500	6,280,058
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)		153,109,406	155,896,972
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		6,754,490	6,852,803
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	208,022,097	184,292,080
73	Prelim. Survey and Investigation Charges (Electric) (183)		242,826	4,041,357
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)		874,939	52,349
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	1,758,271	1,940,707
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)		7,710,768	8,384,226
82	Accumulated Deferred Income Taxes (190)	234	83,865,109	100,358,336
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		309,228,500	305,921,858
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		2,484,383,335	2,446,539,336

Schedule Page: 110 Line No.: 2 Column: c

Reconciliation to Ferc Pg 200:

2,885,398,614	Ferc Pg 200, Line 8
872,756	Ferc Pg 200, Line 10
2,886,271,370	Ferc Pg 200, Lines 8 & 10
80,777	Non-Utility - Regulated
151,312	Non-Utility - Electric Vehicle Charging Stations
2,886,503,459	Ferc Pg 110, Line 2

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

979,349,137	Ferc Pg 110, Line 5
(10,743)	Non-Regulated Non-Utility
979,338,394	Ferc Pg 200, Line 14, 22 & 33

Schedule Page: 110 Line No.: 35 Column: c

Reconciliation to Ferc Pg 121:

7,837,553	Cash (131), Ferc Pg 110, Line 35
167,286	Working Fund (135) Ferc Pg 110, Line 37
0	Temporary Cash Investments Ferc Pg 110, Line 38
8,004,839	Ties to Cash Flow Statement Ferc Pg 121, Line 90

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
The Empire District Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/13/2019	end of 2018/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	43,993,363	43,993,363
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		684,085,854	684,085,854
7	Other Paid-In Capital (208-211)	253	866,935	866,935
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	21,935,000	21,935,000
11	Retained Earnings (215, 215.1, 216)	118-119	114,690,933	92,809,653
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	31,301,754	27,689,937
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)		853,003,839	827,510,742
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	588,000,000	678,000,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	90,000,000	0
21	Other Long-Term Debt (224)	256-257	102,000,000	102,000,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		479,387	528,517
24	Total Long-Term Debt (lines 18 through 23)		779,520,613	779,471,483
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		2,481,747	2,838,492
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		6,382,943	4,748,490
29	Accumulated Provision for Pensions and Benefits (228.3)		98,554,577	68,982,556
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		160,218	160,218
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)		19,003,570	21,286,536
35	Total Other Noncurrent Liabilities (lines 26 through 34)		126,583,055	98,016,292
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		6,000,000	5,575,000
38	Accounts Payable (232)		32,632,617	43,512,247
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		10,772,793	23,479,677
41	Customer Deposits (235)		14,768,228	13,943,944
42	Taxes Accrued (236)	262-263	28,450,586	5,258,231
43	Interest Accrued (237)		6,786,879	6,921,023
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	end of 2018/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		844,444	722,837
48	Miscellaneous Current and Accrued Liabilities (242)		30,259,254	29,386,449
49	Obligations Under Capital Leases-Current (243)		381,795	369,090
50	Derivative Instrument Liabilities (244)		872,030	2,035,170
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)		131,768,626	131,203,668
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		4,458,733	2,910,988
57	Accumulated Deferred Investment Tax Credits (255)	266-267	17,734,175	17,734,175
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	4,958,439	6,026,632
60	Other Regulatory Liabilities (254)	278	243,717,777	224,028,030
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	16,955,758	27,365,522
63	Accum. Deferred Income Taxes-Other Property (282)		257,923,136	269,012,200
64	Accum. Deferred Income Taxes-Other (283)		47,759,184	63,259,604
65	Total Deferred Credits (lines 56 through 64)		593,507,202	610,337,151
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		2,484,383,335	2,446,539,336

Schedule Page: 112 Line No.: 12 Column: c

Worsheet Q (Line 8) of the Company's GFR & Worksheet ATT-11 (Line 5) of the Company's TFR increase the unappropriated undistributed subsidiary earnings by $3,751,000 to include the EDG bond expense that is part of the Company's consolidated capital structure.

Schedule Page: 112 Line No.: 12 Column: d

Worksheet Q (Line 7) of the Company's GFR & Worksheet ATT-11 (Line 4) of the Company's TFR increase the unappropriated undistributed subsidiary earnings by $3,751,000 to include the EDG bond expense that is part of the Company's consolidated capital structure.

Schedule Page: 112 Line No.: 18 Column: c

Worksheet Q (Line 5) of the Company's GFR & Worksheet ATT-11 (Line 3) of the Company's TFR increase the Long Term Debt by $55,000,000 to include the EDG bond which is part of the Company's consolidated capital structure.

Schedule Page: 112 Line No.: 18 Column: d

Worksheet Q (Line 4) of the Company's GFR & Worsheet ATT-11 (Line 2) of the Company's TFR increase the Long Term Debt by $55,000,000 to include the EDG bond which is part of the Company's consolidated capital structure.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

STATEMENT OF INCOME

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

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

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	634,641,065	584,766,413		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	296,570,293	248,863,700		
5	Maintenance Expenses (402)	320-323	51,745,642	46,848,764		
6	Depreciation Expense (403)	336-337	78,167,670	75,940,155		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	3,851,726	3,462,768		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)					
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	35,308,358	36,375,054		
15	Income Taxes - Federal (409.1)	262-263	17,927,353	2,056,631		
16	- Other (409.1)	262-263	-2,914,888	2,847,793		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	-17,634,589	76,490,289		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	-15,985,956	-3,222,115		
19	Investment Tax Credit Adj. - Net (411.4)	266		-142,820		
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)		10,511	11		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		478,997,010	495,964,438		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		155,644,055	88,801,975		

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
632,565,359	582,711,333			2,075,706	2,055,080	2
						3
295,503,035	247,918,769			1,067,258	944,931	4
51,194,374	46,433,155			551,268	415,609	5
77,800,592	75,633,971			367,078	306,184	6
						7
3,851,726	3,462,768					8
						9
						10
						11
						12
						13
35,189,075	36,266,679			119,283	108,375	14
17,927,353	2,154,611				-97,980	15
-2,914,888	2,863,190				-15,397	16
-17,634,589	76,239,092				251,197	17
-15,985,851	-3,219,563			-105	-2,552	18
	-141,239				-1,581	19
						20
						21
10,511	11					22
						23
						24
476,892,018	494,050,548			2,104,992	1,913,890	25
155,673,341	88,660,785			-29,286	141,190	26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		155,644,055	88,801,975		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)					
35	Nonoperating Rental Income (418)		-2,414	-1,993		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	3,611,817	6,954,662		
37	Interest and Dividend Income (419)		710,139	250,153		
38	Allowance for Other Funds Used During Construction (419.1)		1,383,710	874,194		
39	Miscellaneous Nonoperating Income (421)		-266,708	-208,496		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		5,436,544	7,868,520		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			179,945		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		408,188	403,473		
46	Life Insurance (426.2)					
47	Penalties (426.3)		789	-1,455		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		518,327	483,440		
49	Other Deductions (426.5)		379,975	39,347,365		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		1,307,279	40,412,768		
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		-286,926		
54	Income Taxes-Other (409.2)	262-263		-40,882		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277		98,017		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	19,941	20,487,712		
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)		-19,941	-20,717,503		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		4,149,206	-11,826,745		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		34,984,025	38,330,900		
63	Amort. of Debt Disc. and Expense (428)		476,629	543,010		
64	Amortization of Loss on Reaquired Debt (428.1)		673,458	673,458		
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)		2,378,250			
68	Other Interest Expense (431)		1,622,438	1,248,010		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		820,577	554,066		
70	Net Interest Charges (Total of lines 62 thru 69)		39,314,223	40,241,312		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		120,479,038	36,733,918		
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)		120,479,038	36,733,918		

Schedule Page: 114 Line No.: 6 Column: g

Reconciliation to Ferc Pg 336:

77,800,592	Ferc Pg 115, Line 6
(7,566)	Non-Regulated Non-Utility
77,793,026	Ferc Pg 336, Line 12, Col b

Schedule Page: 114 Line No.: 62 Column: c

This footnote applies to Ferc Pg 117, Line 62, Column c. Worksheet Q (Line 3) of the Company's GFR and Worksheet ATT-11 (Line 1) of the TFR increase the interest expense paid by $3,751,000 to include the EDG bond expense that is part of the Company's consolidated capital structure.

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		92,403,430	94,674,445
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)		116,867,222	29,779,256
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				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31	Dividends - Common Stock		-94,985,941	(32,050,271)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-94,985,941	(32,050,271)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		114,284,711	92,403,430
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		406,223	406,223
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		406,223	406,223
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		114,690,934	92,809,653
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		27,689,937	20,735,275
50	Equity in Earnings for Year (Credit) (Account 418.1)		3,611,817	6,954,662
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		31,301,754	27,689,937

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	120,479,038	36,733,918
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	84,016,220	81,404,379
5	Amortization of Debt Issue Costs & Debt Discounts	600,410	666,790
6	Pension Expense & Post Retirement Benefit Costs	6,349,641	16,542,999
7	Non-Cash (Gain)/Loss on Derivatives, Loss on Plant Disallow & Other	4,996,487	2,719,728
8	Deferred Income Taxes (Net)	-1,668,578	59,522,792
9	Investment Tax Credit Adjustment (Net)		-342,905
10	Net (Increase) Decrease in Receivables	1,052,722	-13,076,285
11	Net (Increase) Decrease in Inventory	-1,787,277	-3,307,256
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-2,009,571	9,815,670
14	Net (Increase) Decrease in Other Regulatory Assets	24,936,833	8,364,307
15	Net Increase (Decrease) in Other Regulatory Liabilities	-3,963,887	-10,424,375
16	(Less) Allowance for Other Funds Used During Construction	1,383,710	874,194
17	(Less) Undistributed Earnings from Subsidiary Companies	3,611,817	6,954,662
18	Other (provide details in footnote): Cust Dep, Interest & Taxes Accr	14,314,167	4,633,300
19	Other Liab & Other Def Credits, Prepaid Exp & Deferred Charges	-5,176,130	-28,665,027
20	Issuance of Common Stock & Stock Options for Incentive Plans		-85,456
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	237,144,548	156,673,723
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)		
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-1,383,710	-874,194
31	Other (provide details in footnote):		
32	Construction and Acquisition of Plant (including land)	-129,084,924	-113,124,646
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-127,701,214	-112,250,452
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	544,538	-368,755
40	Contributions and Advances from Assoc. and Subsidiary Companies	-12,706,884	11,461,783
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote): Restricted Cash		
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-139,863,560	-101,157,424
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	90,000,000	
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	425,000	
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	90,425,000	
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-90,797,008	-819,227
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		-19,175,000
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-95,000,000	-35,896,360
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-95,372,008	-55,890,587
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	1,908,980	-374,288
87			
88	Cash and Cash Equivalents at Beginning of Period	6,095,859	6,470,147
89			
90	Cash and Cash Equivalents at End of period	8,004,839	6,095,859

Schedule Page: 120 Line No.: 18 Column: b

464,244 Income Taxes Paid (Received), Net of Refund

38,541,604 Interest Paid

Schedule Page: 120 Line No.: 53 Column: c

Statement of Cash Flows Presentation of Changes in Restricted Cash: In November 2016, the FASB issued revised guidance addressing the presentation of changes in restricted cash on the statement of cash flows intended to address diversity in practice. Under the revised guidance, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. The Empire District Electric Company adopted this on January 1, 2018, and the cash flow statement has been changed for 2017 to be consistent with the new guidance.

Schedule Page: 120 Line No.: 57 Column: c

See Footnote on Line 53.

Schedule Page: 120 Line No.: 86 Column: c

See Footnote on Line 53.

Schedule Page: 120 Line No.: 88 Column: c

See Footnote on Line 53.

Schedule Page: 120 Line No.: 90 Column: b

Reconciliation to Ferc Pg 110:

7,837,553	Cash (131), Ferc Pg 110, Line 35
167,286	Working Fund (135) Ferc Pg 110, Line 37
0	Temporary Cash Investments Ferc Pg 110, Line 38
8,004,839	**Ties to Cash Flow Statement Ferc Pg 121, Line 90**

Schedule Page: 120 Line No.: 90 Column: c

See Footnote on Line 53.

NOTES TO FINANCIAL STATEMENTS

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

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

The Empire District Electric Company

Notes to Consolidated Financial Statements

Basis of Accounting

Accounting policies for regulated operations are in accordance with those prescribed by the regulatory authorities having jurisdiction, principally the Missouri Public Service Commission (MoPSC), the Federal Energy Regulatory Commission (FERC) and the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 2005 (PUHCA). 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 (USOA) and accounting releases, which require certain differences from accounting principles generally accepted in the United States (GAAP). The differences between the accounting requirements of FERC and GAAP include, but are not limited to the following:

*Balance sheet presentation of asset removal costs, accumulated deferred income taxes, uncertain tax positions, property, plant and equipment, regulatory assets, and regulatory liabilities.

*Income statement classification of certain items between operating revenues and expenses and nonoperating revenues and expenses.

*Cash flow classification of the purchase and sales of renewable energy credits and fees related to credit facilities.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Pursuant to an Agreement and Plan of Merger ("the Merger Agreement"), dated as of February 9, 2016, by and among The Empire District Electric Company ("Empire" or "EDE"), Liberty Utilities (Central) Co. ("Liberty Central") (an indirect subsidiary of Algonquin Power & Utilities Corp. ("Algonquin" or "APUC")) and Liberty Sub Corp. ("Merger Sub"), a wholly owned direct subsidiary of Liberty Central, Merger Sub merged with and into Empire, with Empire surviving the merger and becoming a wholly owned direct subsidiary of Liberty Central ("the Merger"). The Merger closed effective January 1, 2017 ("the Closing Date"). As a result, effective with the closing of the Merger, Empire ceased to be a publicly-held corporation and Empire common stock ceased trading on the New York Stock Exchange. Since Merger Sub had nominal net assets and, since Empire did not apply pushdown accounting related to Liberty Central's acquisition of Empire under ASU 2014-17, the Merger did not have any impact on the financial statements of Empire other than Merger-related expenses. See Note 15 for further discussion of the Merger Agreement.

We operate our businesses as three segments: electric, gas and other. Empire, a Kansas corporation organized in 1909, is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. As part of our electric segment, we also provide water service to three towns in Missouri. The Empire District Gas Company (EDG) is our wholly owned subsidiary engaged in the distribution of natural gas in Missouri. Our other segment consists of our fiber optics business. Our gross operating revenues in 2018 were derived as follows:

Electric segment sales*		92.8%
On-system revenues	86.2 %	
SPP IM revenues	4.5	
Other revenues	1.8	
Gas segment sales		6.3
Other segment sales		0.9

*Sales from our electric segment include 0.3% from the sale of water.

The utility portions of our business are subject to regulation by the Missouri Public Service Commission (MPSC), the State Corporation Commission of the State of Kansas (KCC), the Corporation Commission of Oklahoma (OCC), the Arkansas Public Service Commission (APSC) and the Federal Energy Regulatory Commission (FERC). Our accounting policies are in accordance with the rate-making practices of the regulatory authorities and conform to generally accepted accounting principles as applied to regulated public utilities.

Our electric operations serve approximately 174,000 customers as of December 31, 2018, and the 2018 electric operating revenues were derived as follows:

Customer Class	% of revenue
Residential	42.7%
Commercial	29.2
Industrial	15.2
Wholesale on-system	3.5
Wholesale off-system	4.9
Miscellaneous sources, primarily public authorities	2.6
Other electric revenues	1.9

Our retail electric revenues for 2018 by jurisdiction were as follows:

Jurisdiction	% of revenue
Missouri	90.5 %
Kansas	4.2
Oklahoma	2.4
Arkansas	2.9

Our gas operations serve approximately 43,200 customers as of December 31, 2018, and the 2018 gas operating revenues were derived as follows:

Customer Class	% of revenue
Residential	63.3%
Commercial	25.5
Industrial	0.9
Transportation	8.5
Miscellaneous	1.8

Basis of Presentation

The consolidated financial statements include the accounts of EDE, EDG, and our other subsidiaries. The consolidated entity is referred to throughout as “we” or “the Company”. All intercompany balances and transactions have been eliminated in consolidation. Certain immaterial reclassifications have been made to prior year information to conform to the current year presentation.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles (US GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements. Estimates also affect the reported amounts of revenues and expenses during the period. Areas in the consolidated financial statements significantly affected by estimates and assumptions include unbilled utility revenues, collectability of accounts receivable, depreciable lives, asset impairments and goodwill impairment evaluations, employee benefit obligations, contingent liabilities, asset retirement obligations, the fair value of stock-based compensation, and tax provisions. Actual amounts could differ from those estimates.

Accounting for the Effects of Regulation

In accordance with the Accounting Standard Codification (ASC) guidance for regulated operations, our consolidated financial statements reflect rate-making policies prescribed by the regulatory commissions having jurisdiction over our regulated generation and other utility operations (the MPSC, the KCC, the OCC, the APSC and the FERC).

We record a regulatory asset for all or part of an incurred cost that would otherwise be charged to expense in accordance with the ASC guidance for regulated operations which says that an asset should be recorded if it is probable that future revenue in an amount at least equal to the capitalized cost will be allowable for rate-making purposes and the current available evidence indicates that future revenue will be provided to permit recovery of the cost. This guidance also indicates that a liability should be recorded when a regulator has provided current recovery for a cost that is expected to be incurred in the future. We follow this guidance for incurred costs or credits that are subject to future recovery from or refund to our customers in accordance with the orders of our regulators.

Historically, all costs of this nature, which are determined by our regulators to have been prudently incurred, have been recoverable through rates in the course of normal rate-making procedures. Regulatory assets and liabilities are ratably amortized through a charge or credit, respectively, to earnings while being recovered in revenues and fully recognized if and when it is no longer probable that such amounts will be recovered through future revenues. We generally include amortization of regulatory assets and liabilities in the depreciation and amortization line of our consolidated statement of cash flows. We continually assess the recoverability of our regulatory assets. Although we believe it unlikely, should retail electric competition legislation be passed in the states we serve, we may determine that we no longer meet the criteria set forth in the ASC guidance for regulated operations with respect to continued recognition of some or all of the regulatory assets and liabilities. Any regulatory changes that would require us to discontinue application of this guidance based upon competitive or other events may also impact the valuation of certain utility plant investments. Impairment of regulatory assets or utility plant investments could have a material adverse effect on our financial condition and results of operations. See Note 3 for further discussion of regulatory assets and liabilities.

Revenue Recognition

For our utility operations, we use cycle billing and accrue estimated, but unbilled, revenue for services provided between the last bill date and the period-end date. Unbilled revenues represent the estimate of receivables for energy and natural gas services delivered, but not yet billed to customers. The accuracy of our unbilled revenue estimate is affected by factors including fluctuations in energy demands, weather, line losses and changes in the composition of customer classes.

Municipal Franchise Taxes

Municipal franchise taxes are collected for and remitted to their respective entities and are included in operating revenues and other taxes in the consolidated statements of income. Municipal franchise taxes of $12.9 million and $11.4 million were recorded for each of the years ended December 31, 2018 and 2017, respectively.

Accounts Receivable

Accounts receivable are recorded at the tariffed rates for customer usage, including applicable taxes and fees and do not bear interest. We review the outstanding accounts receivable monthly, as well as the bad debt write-offs experienced in the past, and establish an allowance for doubtful accounts. Account balances are charged off against the allowance when management determines it is probable the receivable will not be recovered.

Property, Plant & Equipment

The costs of additions to utility property and replacements for retired property units are capitalized. Costs include labor, material, an allocation of general and administrative costs, and an allowance for funds used during construction (AFUDC). The original cost of regulated units retired or disposed of and the costs of removal are charged to accumulated depreciation, unless the removed property constitutes an operating unit or system. In this case, a gain or loss is recognized upon the disposal of the asset. Maintenance expenditures and the removal of minor property items are charged to income as incurred. A liability is created for any additions to electric or gas utility property that are paid for by advances from developers. For a period of five years, we refund to the developer a pro-rata amount of the original cost of the extension for each new customer added to the extension. Nonrefundable payments at the end of the five-year period are applied as a reduction to the cost of the plant in service. The liability as of December 31, 2018 and 2017 was $4.5 million and $2.9 million, respectively.

Depreciation

Provisions for depreciation are computed at straight-line rates in accordance with GAAP consistent with rates approved by regulatory authorities. These rates are applied to the various classes of utility assets on a composite basis. Provisions for depreciation for our other segment are computed at straight-line rates over the estimated useful lives of the properties. See Note 2 for additional details regarding depreciation rates.

As of December 31, 2018 and 2017, we had recorded accrued cost of removal of $93.9 million and $87.8 million, respectively, for our electric operating segment. This amount, recorded as a regulatory liability, represents an estimated future cost of dismantling and removing plant from service upon retirement, accrued as part of our depreciation rates. We accrue cost of removal in depreciation rates for mass property (including transmission, distribution and general plant assets). These accruals are not considered an asset retirement obligation under the guidance provided on asset retirement obligations within the ASC. We have a similar cost of removal regulatory liability for our gas operating segment. This amount accrued at December 31, 2018 and 2017 was $11.9 million and $11.2 million, respectively. These amounts are net of our actual cost of removal expenditures.

Asset Retirement Obligation (ARO)

We record the estimated fair value of legal obligations associated with the retirement of tangible long-lived assets in the period in which the liabilities are incurred and capitalize a corresponding amount as part of the book value of the related long-lived asset. In subsequent periods, we are required to adjust asset retirement obligations based on changes in estimated fair value, and the corresponding increases in asset book values are depreciated over the useful life of the related asset. Uncertainties as to the probability, timing or cash flows associated with an asset retirement obligation affect our estimate of fair value.

We have identified asset retirement obligations associated with the future removal of certain river water intake structures and equipment at the Iatan Power Plant, in which we have a 12% ownership. We also have asset retirement obligations associated with the removal of asbestos located at the Asbury Power Plant, the closure of a solid waste landfill at the Plum Point Energy Station, and closure of existing coal combustion residual (CCR) impoundments at our Asbury Power Plant and Iatan Generating Station. During 2017, the liabilities for the solid waste landfill at the Plum Point Energy Station and the CCR impoundment at the Iatan Power Plant were revised to reflect new cost estimates and changes in the expected timing of the future cash flows. These changes increased the ARO obligation by approximately $0.1 million. The obligation related to the removal of asbestos at our Riverton Power Plant was revised upward by approximately $1.0 million to reflect the expected timing of its settlement. During 2017, the necessary asbestos remediation work was completed at our Riverton Power Plant and the related asset retirement obligation was settled. During 2018, the liability for the CCR impoundment at our Iatan Power Plant was re-evaluated and increased by $2.2 million based on updated cost estimates.

In addition, we have a liability for the removal and disposal of Polychlorinated Biphenyls (PCB) contaminants associated with our transformers and substation equipment. These liabilities have been estimated based upon either third-party costs or historical review of expenditures for the removal of similar past liabilities. The potential costs of these future expenditures are based on engineering estimates of third-party costs to remove the assets in satisfaction of the associated obligations. This liability will be accreted over the period up to the estimated settlement date.

All of our recorded asset retirement obligations have been estimated as of the expected retirement date, or settlement date, and have been discounted using a credit adjusted risk-free rate ranging from 1.93% to 5.52% depending on the settlement date. Revisions to these liabilities could occur due to changes in the cost estimates, anticipated timing of settlement or federal or state regulatory requirements.

The balances at the end of 2018 and 2017, recorded in other liabilities, are shown below.

(000's)	Liability Balance at 12/31/17	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions	Liability Balance at 12/31/18
Asset retirement obligation	$ 21,316	$ -	$ (5,130)	$ 653	$ 2,195	$ 19,034

(000's)	Liability Balance at 12/31/16	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions	Liability Balance at 12/31/17
Asset retirement obligation	$ 23,545	$ -	$ (4,174)	$ 808	$ 1,137	$ 21,316

Upon adoption of the standards on the retirement of long-lived assets and conditional asset retirement obligations, we recorded a liability and regulatory asset because we expect to recover these costs of removal in electric and gas rates either through depreciation accruals or direct expenses. We also defer the liability accretion and depreciation expense as a regulatory asset. At December 31, 2018 and 2017, our regulatory assets relating to asset retirement obligations totaled $21.0 million and $16.1 million, respectively.

Allowance for Funds Used During Construction

As provided in the FERC regulatory Uniform System of Accounts, utility plant is recorded at original cost, including an allowance for funds used during construction (AFUDC) when first placed in service. The AFUDC is a utility industry accounting practice whereby the cost of borrowed funds and the cost of equity funds applicable to construction programs are capitalized as a cost of construction. This accounting practice offsets the effect on earnings of the cost of financing current construction, and treats such financing costs in the same manner as construction charges for labor and materials.

AFUDC does not represent current cash income. Recognition of this item as a cost of utility plant is in accordance with regulatory rate practice under which such plant costs are permitted as a component of rate base and the provision for depreciation.

In accordance with the methodology prescribed by the FERC, we utilized aggregate rates of 6.8% for 2018 and 5.5% for 2017, compounded semiannually.

Asset Impairments (excluding goodwill)

We review long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. To the extent that certain assets may be impaired, analysis is performed based on undiscounted forecasted cash flows to assess the recoverability of the assets and, if necessary, the fair value is determined to measure the impairment amount. None of our assets were impaired as of December 31, 2018 and 2017.

Goodwill

As of December 31, 2018, the consolidated balance sheet included $39.5 million of goodwill. All of this goodwill was derived from our 2006 gas company acquisition and recorded in our gas segment, which is also the reporting unit for goodwill testing purposes. Accounting guidance requires us to test goodwill for impairment on an annual basis or whenever events or circumstances indicate possible impairment.

We applied a qualitative goodwill evaluation model for the annual goodwill impairment test completed in 2018. Based on the results of the qualitative assessment, we believe it was more likely than not that the fair value of the reporting unit exceeded its carrying value as of the testing date, indicating no impairment of our goodwill. The following factors, among others, were considered when assessing whether it was more likely than not that the fair value of the reporting unit exceeded its carrying value for the 2018 test:

* Actual and forecasted financial performance
* Macroeconomic conditions
* Observable industry market multiples

Fuel and Purchased Power

Electric Segment

Fuel and purchased power costs are recorded at the time the fuel is used, or the power purchased. Southwest Power Pool (SPP) Integrated Marketplace (IM) purchased power is also included in fuel and purchased power costs. The net effects of our SPP IM activity, including SPP IM net revenue and net purchased power costs, flow through our fuel recovery mechanisms in each state.

In our Missouri jurisdiction, the MPSC establishes a base cost for the recovery of fuel and purchased power expenses used to supply energy for our fuel adjustment clause (FAC). The FAC permits the distribution to customers of 95% of the changes in fuel and purchased power costs prudently incurred above or below the base cost. Rates related to the fuel adjustment clause are modified twice a year subject to the review and approval by the MPSC. In accordance with the ASC guidance for regulated operations, 95% of the difference between the actual costs of fuel and purchased power and the base cost of fuel and purchased power recovered from our customers is recorded as an adjustment to fuel and purchased power expense with a corresponding regulatory asset or regulatory liability. If the actual fuel and purchased power costs are higher or lower than the base fuel and purchased power costs billed to customers, 95% of these amounts will be recovered from or refunded to our customers when the fuel adjustment clause is modified.

In our Kansas jurisdiction, the costs of fuel are recovered from customers through a fuel adjustment clause, based upon estimated fuel costs and purchased power. The adjustments are subject to audit and final determination by regulators. The difference between the costs of fuel used and the cost of fuel recovered from our Kansas customers is recorded as a regulatory asset or a regulatory liability if the actual costs are higher or lower than the costs billed to customers, in accordance with the ASC guidance for regulated operations.

Similar fuel recovery mechanisms are in place for our Oklahoma, Arkansas and FERC jurisdictions.

At December 31, 2018 and 2017, our Missouri, Kansas and Oklahoma fuel and purchased power costs were in a net under-recovered position by $3.7 million and net under-recovered position by $12.6 million, respectively, which are reflected in our regulatory assets and liabilities.

We receive the renewable attributes associated with the power purchased through our purchased power agreements with Elk River Windfarm LLC and Cloud County Windfarm, LLC. These renewable attributes are converted into renewable energy credits (RECs), which are considered inventory, and recorded at zero cost (See Note 11). Revenue from the sale of RECs reduces fuel and purchased power expense.

We have a Stipulation and Agreement with the MPSC granting us authority to manage our emissions allowance inventory in accordance with our Plan for Purchasing and Selling Emissions Allowances (PPSEMA). The PPSEMA allows us to purchase allowances needed for compliance, exchange banked allowances for future vintage allowances and/or monetary value and, in extreme market conditions, to sell allowances outright for monetary value. For compliance years 2018 and 2017 we did not exchange or sell any allowances. We classify our allowances as inventory and they are recorded at cost, with allocated allowances being recorded at zero cost. The allowances are removed from inventory on a FIFO basis, and used allowances are considered to be a part of fuel expense (See Note 11). We had the following emissions allowances in inventory at December 31, 2018 and 2017:

Emission Allowances in Inventory	2018	2017
Acid Rain SO2	43,852	32,890
CSAPR SO2	15,916	10,891
CSAPR NOx (annual)	2,368	1,539
CSAPR NOx (seasonal)	216	89

Gas Segment

Fuel expense for our gas segment is recognized when the natural gas is delivered to our customers, based on the current cost recovery allowed in rates. A Purchased Gas Adjustment (PGA) clause allows EDG to recover from our customers, subject to audit and final determination by regulators, the cost of purchased gas supplies and related carrying costs associated with the Company's use of natural gas financial instruments to hedge the purchase price of natural gas. This PGA clause allows us to make rate changes periodically (up to four times) throughout the year in response to weather conditions and supply demands, rather than in one possibly extreme change per year.

We calculate the PGA factor based on our best estimate of our annual gas costs and volumes purchased for resale. The calculated factor is reviewed by the MPSC staff and approved by the MPSC. Elements considered part of the PGA factor include cost of gas supply, storage costs, hedging contracts, revenue and refunds, prior period adjustments and transportation costs.

Pursuant to the provisions of the PGA clause, the difference between actual costs incurred and costs recovered through the application of the PGA (including costs, cost reductions and carrying costs associated with the use of financial instruments) are reflected as a regulatory asset or liability. The balance is amortized as amounts are reflected in customer billings.

Derivatives

We utilize derivatives to help manage our natural gas commodity market risk resulting from purchasing natural gas, to be used as fuel in our electric business or sold in our natural gas business. We also acquire Transmission Congestion Rights (TCRs) in an attempt to mitigate congestion costs associated with the power we purchase from the SPP IM (See Note 13).

Electric Segment

Pursuant to the ASC guidance on accounting for derivative instruments and hedging activities, derivatives are required to be recognized on the consolidated balance sheets at their fair value. On the date a derivative contract is entered into, the derivative is designated as (1) a hedge of a forecasted transaction or of the variability of cash flows to be received or paid related to a recognized asset or liability ("cash-flow" hedge); or (2) an instrument that is held for non-hedging purposes (a "non-hedging" instrument). We record the mark-to-market gains or losses on derivatives used to hedge our fuel as regulatory assets or liabilities. This is in accordance with the ASC guidance on regulated operations, given that those regulatory assets and liabilities are probable of recovery through our fuel adjustment mechanism.

We also enter into fixed-price forward physical contracts for the purchase of natural gas, coal and purchased power. These contracts, if they meet the definition of a derivative, are not subject to derivative accounting because they are considered to be normal purchase normal sales (NPNS) transactions. If these transactions do not qualify for NPNS treatment, they would be marked to market for each reporting period through regulatory assets or liabilities.

Gas Segment

Financial hedges for our natural gas business are recorded at fair value on our consolidated balance sheets. Because we have a commission approved natural gas cost recovery mechanism (PGA), we record the mark-to-market gain/loss on natural gas financial hedges each reporting period to a regulatory asset/liability account. The regulatory asset/liability account tracks the difference between revenues billed to customers for natural gas costs and actual natural gas expense which is trued up at the end of August each year and included in the Actual Cost Adjustment (ACA) factor to be billed to customers during the next year. This is consistent with the ASC guidance on regulated operations, in that we will be recovering our costs after the annual true-up period (subject to a prudency review by the MPSC).

Cash flows from hedges for both the electric and gas segments are classified within cash flows from operations.

Pension and Other Postemployment Benefits

We recognize expense related to pension and other postemployment benefits (OPEB) as earned during the employee's period of service. Related assets and liabilities are established based upon the funded status of the plan compared to the projected benefit obligation. Our pension and OPEB expense or benefit includes amortization of previously unrecognized net gains or losses. Additional income or expense may be recognized when our unrecognized gains or losses as of the most recent measurement date exceed 10% of our postemployment benefit obligation or fair value of plan assets, whichever is greater. For pension benefits and OPEB benefits, unrecognized net gains or losses as of the measurement date are amortized into actuarial expense over ten years.

Pensions

We have rate orders with Missouri, Kansas and Oklahoma that allow us to recover pension costs consistent with our GAAP policy noted above. In accordance with the rate orders, we prospectively calculate the value of plan assets using a market-related value method as allowed by the ASC guidance on pension benefits. As a result, we are allowed to record the Missouri, Kansas and Oklahoma portion of any costs above or below the amount included in rates as a regulatory asset or liability, respectively. The MPSC has allowed us to adopt this pension cost recovery methodology for EDG as well.

Other Postemployment Benefits

We have regulatory treatment for our OPEB costs similar to the treatment described above for pension costs. This includes the use of a market-related value of assets, the amortization of unrecognized gains or losses into actuarial expense over ten years and the recognition of regulatory assets and liabilities as described above.

Additional guidance in the ASC on employers' accounting for defined benefit pension and other postemployment plans requires an employer to recognize the overfunded or underfunded status of a defined benefit postemployment plan (other than a multiemployer plan) as an asset or liability in its balance sheet and to recognize changes in that funded status in the year in which the changes occur through the comprehensive income of a business entity. The guidance also requires an employer to measure the funded status of a plan as of the date of its year-end balance sheet, with limited exceptions. Pension and other postemployment employee benefits tracking mechanisms are utilized to allow for future rate recovery of these obligations. We record these as regulatory assets on the consolidated balance sheets rather than as reductions of equity through comprehensive income (See Note 7).

Unamortized Debt Discount, Premium and Expense

Discount, premium and expense associated with long-term debt are amortized over the lives of the related issues. Costs, including gains and losses, related to refunded long-term debt are amortized over the lives of the related new debt issues, in accordance with regulatory rate practices.

Liability Insurance

We are primarily self-insured for general liabilities, benefits paid under employee healthcare programs and long-term disability benefits. Accruals are primarily based on the estimated undiscounted cost of claims. We self-insure up to certain limits that vary by segment and type of risk. Periodically, we evaluate the level of insurance coverage over the self-insured limits and adjust insurance levels based on risk tolerance and premium expense. We carry excess liability insurance for public liability claims for segments of our business. In order to provide for the cost of losses not covered by insurance, an allowance for injuries and damages is maintained based on our loss experience. Workers' compensation claims are covered by a guaranteed cost policy for all business segments.

Other Noncurrent Liabilities

Other noncurrent liabilities are comprised of accruals and other accounting estimates not sufficiently large enough to merit individual disclosure. At December 31, 2018 and 2017, the balance of other noncurrent liabilities is primarily comprised of accruals for self-insurance, customer advances for construction and asset retirement obligations.

Cash & Cash Equivalents

Cash and cash equivalents include cash on hand and temporary investments purchased with an initial maturity of three months or less. It also includes checks and electronic funds transfers that have been issued but have not cleared the bank, which are also reflected in current accrued liabilities and were $22.9 million and $24.1 million at December 31, 2018 and 2017, respectively.

Restricted Cash

As part of our Plum Point ownership agreement, we are required to have funds available in an escrow account which guarantees payment of certain operating costs. The cash is held at a financial institution and restricted as to withdrawal or use. The amounts restricted, which were $1.8 million at December 31, 2018 and 2017, may increase or decrease based on an annual review.

We are required to post cash collateral with the SPP to participate in TCR auctions. The cash is held at a financial institution and restricted as to withdrawal or use. The amounts of such restricted cash were $2.5 million at December 31, 2018 and 2017.

Due to our Plum Point energy station interconnection with Midcontinent Independent System Operator (MISO), we participate in Financial Transmission Rights (FTR) auctions which require us to post cash collateral. The cash is held at a financial institution and restricted as to withdrawal or use. The amounts of such restricted cash were $0.5 million at December 31, 2018 and 2017.

Fuel, Materials and Supplies

Fuel, materials and supplies consist primarily of coal, natural gas in storage and materials and supplies, which are reported at average cost. These balances are as follows (in thousands):

		2018		2017
Electric fuel inventory	$	21,691	$	24,116
Natural gas inventory		2,839		3,274
Materials and supplies		37,164		32,772
TOTAL	**$**	**61,694**	**$**	**60,162**

Income Taxes

Deferred tax assets and liabilities are recognized for the tax consequences of transactions that have been treated differently for financial reporting and tax return purposes. The temporary differences are measured using statutory tax rates (See Note 9).

Investment tax credits utilized in prior years were deferred as a noncurrent liability and are being amortized over the useful lives of the properties to which they relate. The longest remaining amortization period for investment tax credits is approximately 42 years. Deferred income taxes were recorded on the temporary difference represented by the deferred investment tax credits and a corresponding regulatory liability. This recognizes the expected reduction in rates for future lower income taxes associated with the amortization of the investment tax credits.

Accounting for Uncertainty in Income Taxes

The FASB has issued guidance on accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with the ASC guidance on accounting for income taxes. With few exceptions, we are no longer subject to U.S. federal, state and local income tax examinations by tax authorities for years before 2011. At December 31, 2018 and 2017, our consolidated balance sheets did not include provisions for any uncertain tax positions. We do not expect any material changes to this tax position within the next twelve months. Our policy is to recognize interest and penalties, if any, related to unrecognized tax benefits in other expenses.

Recently Issued Accounting Pronouncements

(a) Recently adopted accounting pronouncements

The FASB issued ASU 2018-14, *Compensation—Retirement Benefits—Defined Benefit Plans—General (Subtopic 715-20): Disclosure Framework—Changes to the Disclosure Requirements for Defined Benefit Plans* as part of the disclosure framework project. This update removed certain disclosure requirements regarding AOCI expected to be recognized in income, related party transactions, and certain sensitivity analyses with respect to health care cost trends. This update also added disclosure requirements around the weighted-average interest crediting rates for cash balance plans and explanations for significant gains or losses in the reporting period. The early adoption of this ASU did not have a significant impact on the Company's consolidated financial statements.

The FASB issued ASU 2018-13, *Fair Value Measurement (Topic 820): Disclosure Framework — Changes to the Disclosure Requirements for Fair Value Measurement* as part of the disclosure framework project. This update removed certain disclosure requirements from Topic 820 including the amount of and reasons for transfers between Level 1 and Level 2 measurements, the policy for timing of transfers between levels, and the valuation processes for Level 3 measurements. This update also clarified disclosure requirements relating to measurement uncertainty, and added disclosure requirements for Level 3 measurements, specifically around the changes in unrealized gains and losses included in other comprehensive income and the range and weighted average of significant unobservable inputs. The early adoption of this ASU did not have a significant impact on the Company's consolidated financial statements.

The FASB issued ASU 2018-09, *Codification Improvements* to clarify the Codification and correct unintended application of guidance that is not expected to have a significant impact on current accounting practice. The adoption of this ASU had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2018-03, *Technical Corrections and Improvements to Financial Instruments — Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities* to clarify the Codification and to correct unintended application of the guidance. The Company adopted this pronouncement concurrently with the adoption of ASU 2016-01. The adoption of this update had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2017-09, *Compensation-Stock Compensation (Topic 718): Scope of Modification Accounting*, to provide clarity and reduce both diversity in practice and cost and complexity when applying the guidance in Topic 718, *Compensation-Stock Compensation*, to a change to the terms or conditions of a share-based payment award. The adoption of this update had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2017-07, *Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-retirement Benefit Cost*, to improve the reporting of defined benefit pension cost and post-retirement benefit cost ("net benefit cost") in the financial statements. This update requires the service cost component to be reported in the same line item or items as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The update also only allows the service cost component to be eligible for capitalization when applicable. The Company adopted this guidance effective January 1, 2018. The Company's regulated operations only capitalize the service costs component and therefore no regulatory to U.S. GAAP reporting differences exist. The Company applied the practical expedient for retrospective application on the consolidated statements of operations.

The FASB issued ASU 2017-05, *Other Income—Gains and Losses from the Derecognition of Non-financial Assets (Subtopic 610-20): Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets*. The update clarifies the scope of the standard and provides additional guidance on partial sales of non-financial assets. The adoption of this update had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2017-01, *Business Combinations (Topic 805): Clarifying the Definition of a Business*. The update is intended to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The Company follows the pronouncements of this update as of January 1, 2018.

The FASB issued ASU 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* to eliminate current diversity in practice in the classification and presentation of changes in restricted cash on the statement of cash flows. Prior to the adoption of this update, the Company presented changes in restricted cash as investing activities on the consolidated statement of cash flows.

The FASB issued ASU 2016-16, *Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory*. The new standard requires the recognition of current and deferred income taxes for an intra-entity transfer of an asset other than inventory. The adoption of this update had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230) Classification of Certain Cash Receipts and Cash Payments* in order to eliminate current diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. The adoption of this update had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2016-01, *Financial Instruments — Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities* to simplify the measurement, presentation, and disclosure of financial instruments. The adoption of this update had no significant impact on the Company's consolidated financial statements.

The FASB issued ASC 606, *Revenue from Contracts with Customers* in June 2014, *(Topic 860),* new guidance governing revenue recognition. Under the new guidance, an entity is required to recognize revenue in a pattern that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. Significantly expanded disclosures regarding the qualitative and quantitative information of the Company's nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers are required. This new revenue standard is applicable for fiscal years and interim periods beginning after December 15, 2017 using either a full retrospective approach for all periods presented in the period of adoption or a modified retrospective approach. The Company did not elect to early adopt.

The Company has completed its impact assessment and does not expect significant changes to the pattern of revenue recognition. We adopted the new revenue recognition standard using the modified retrospective method. The only change in the timing of revenue recognition is attributable to our other business unit which will require an increase of $2.5 million in the opening balance of retained earnings. Prior periods will not be retrospectively adjusted. We do not expect the application of the guidance to have a material impact on our results of operations, financial position or liquidity.

(b) Recently issued accounting guidance not yet adopted

The FASB issued ASU 2018-19: *Codification Improvements to Topic 326, Financial Instruments — Credit Losses* as part of its project to correct unintended application of accounting standards. The amendments clarify that receivables arising from operating leases are not within the scope of ASC 326-20. Instead, impairment of receivables arising from operating leases should be accounted for in accordance with Topic 842, *Leases*. The amendments in this Update are effective the same date as Update 2016-13, which is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. The Company is currently assessing the impact of this Update.

The FASB issued ASU 2018-18, *Collaborative Arrangements (Topic 808): Clarifying the Interaction between Topic 808 and Topic 606* to reduce diversity in practice on how entities account for transactions on the basis of different views of the economics of a collaborative arrangement. The Update clarifies that the arrangement should be accounted for under ASC

606 when a participant is a customer in the context of a unit of account, adds unit of account guidance in ASC 808 that is consistent with ASC 606, and precludes the recognition of revenue from a collaborative arrangement with ASC 606 revenue if the participant is not directly related to sales to third parties. The amendments in this Update are effective for fiscal years beginning after December 15, 2019, and interim periods within those years. Early adoption is permitted. The Company is currently assessing the impact of this Update.

The FASB issued ASU 2018-16, *Derivatives and Hedging (Topic 815): Inclusion of the Secured Overnight Financing Rate (“*SOFR*”) Overnight Index Swap (“*OIS*”) Rate as a Benchmark Interest Rate for Hedge Accounting Purposes* to identify a suitable alternative to the U.S. dollar LIBOR that is more firmly based on actual transactions in a robust market. This Update permits the use of the OIS rate based on SOFR as a U.S. benchmark interest rate for hedge accounting purposes. The amendments in this Update are required to be adopted concurrently with the amendments in Update 2017-12, which is required for all fiscal years beginning after December 15, 2018. The amendments will be adopted prospectively for qualifying new or redesignated hedging relationships entered into after the date of adoption.

The FASB issued ASU 2018-15, *Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40*): Customers Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract to provide additional guidance to address diversity in practice. This update aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. Therefore, an entity will follow the guidance in Subtopic 350-40 to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. In addition, the capitalized implementation costs are required to be expensed over the term of the hosting arrangement. This update is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. Early adoption is permitted in any interim period. The amendments can either be applied retrospectively or prospectively to all implementation costs incurred after the date of adoption. The Company is currently assessing the impacts of this update.

The FASB issued ASU 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities*, to improve the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements. The update also makes certain targeted improvements to simplify the application of the hedge accounting guidance. The update is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. The Company does not expect a significant impact on the consolidated financial statements as a result of the adoption of this update.

The FASB issued ASU 2017-04, *Business Combinations (Topic 350): Intangibles — Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment*. The update is intended to simplify how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. Step 2 measures a goodwill impairment loss by comparing the implied fair value of a reporting unit’s goodwill with the carrying amount of that goodwill. The standard is effective for fiscal years and interim periods beginning after December 15, 2019.

The FASB issued ASU 2016-13, Financial Instruments — Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments to provide financial statement users with more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. To achieve this objective, the amendments in this update replace the incurred loss impairment methodology in current GAAP with a methodology that reflects expected credit losses. The standard is effective for fiscal years and interim periods beginning after December 15, 2019. Early adoption for fiscal years and interim periods beginning after December 15, 2018 is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements. The Company does not expect a significant impact on its consolidated financial statements as a result of the adoption of this Update.

The FASB issued ASU 2016-02, Leases (Topic 842) to increase transparency and comparability among organizations utilizing leases. This ASU requires lessees to recognize the assets and liabilities arising from all leases on the balance sheet, but the effect of leases in the statement of operations and the statement of cash flows is largely unchanged. The FASB issued an amendment to ASC Topic 842 that permits companies to elect an optional transition practical expedient to not evaluate existing land easements under the new standard if the land easements were not previously accounted for under existing lease guidance. The FASB issued a further update to ASC Topic 842 in ASU 2018-11 to allow companies to elect not to restate their comparative periods in the period of adoption when transitioning to the standard. The FASB has also issued further codification and narrow-scope improvements to ASC Topic 842 to correct and clarify specific aspects of the guidance. The standard is effective for fiscal years and interim periods beginning after December 15, 2018.

The Company is in the process of finalizing its assessment of the financial, operational, and business processes impacts of the new lease accounting standard. At this point, the Company expects that the adoption of Topic 842 will not have a material impact on the consolidated financial statements. The Company intends to implement new processes and procedures for the identification, analysis, and measurement of new lease contracts on a prospective basis. A new software solution is being implemented to assist with contract management, information tracking, and measurement as it relates to the new standard. The Company intends to elect the following practical expedients as part of its adoption:

* "Package of three" practical expedient that permits the Company not to reassess the scope, classification and initial direct costs of its expired and existing leases;
* Land easements practical expedient that permits the Company not to reassess the accounting for land easements previously not accounted for under ASC 840; and
* Hindsight practical expedient that allows the Company to use hindsight in determining the lease term for existing contracts; and

In addition, the Company will make an accounting policy election to not recognize a lease liability or right-of-use asset on its balance sheet for short-term leases (lease term less than 12 months).

The Company intends to adopt the lease accounting standard retrospectively at the beginning of the period of adoption through a cumulative-effect adjustment.

2. PROPERTY, PLANT AND EQUIPMENT

Our total property, plant and equipment are summarized below for the years ended December 31 (in thousands):

	2018		
	Cost	**Accumulated Depreciation & Amortization**	**Net Book Value**
Plant in Service[1,2]			
Generation	$ 1,436,993	$ 406,434	$ 1,030,559
Transmission	402,480	102,793	299,687
Distribution	1,185,359	424,306	761,053
Construction Work in Progress			
Generation	21,267	-	21,267
Transmission	8,017	-	8,017
Distribution	16,662	-	16,662
	$ 3,070,778	**$ 933,533**	**$ 2,137,245**

	2017		
	Cost	Accumulated Depreciation & Amortization	Net Book Value
Plant in Service(1,2)			
Generation	$ 1,421,731	$ 370,349	$ 1,051,382
Transmission	375,497	97,727	277,770
Distribution	1,138,375	402,558	735,817
Construction Work in Progress			
Generation	9,292	-	9,292
Transmission	12,230	-	12,230
Distribution	11,189	-	11,189
	$ 2,968,314	**$ 870,634**	**$ 2,097,680**

(1) Includes intangible property with a cost of $44.4 million and $42.3 million as of December 31, 2018 and 2017, respectively, primarily related to capitalized software and investments in facility upgrades operated by other utilities. Accumulated amortization related to this property in 2018 and 2017 was $23.4 million and $19.6 million, respectively.
(2) Each group includes an allocated portion of Electric General plant primarily consisting of land, structures and equipment used to support utility operations.

The table below summarizes the total provision for depreciation and the depreciation rates for continuing operations, both capitalized and expensed, for the years ended December 31 (in thousands):

Provision for Depreciation(3)	2018	2017
Generation	$ 38,239	$ 38,057
Transmission	8,626	8,055
Distribution	39,540	38,089
Total Annual Provision for Depreciation	86,405	84,201
Amortization	3,920	3,527
Total Annual Depreciation and Amortization	**$ 90,325**	**$ 87,728**

(3) A portion of this amount is reclassified to a regulatory liability for the estimated future cost of removal. See the depreciation discussion under Note 1 and Note 3 for more details.

Annual Depreciation Rates	2018	2017
Generation	2.8%	2.8%
Transmission	2.3%	2.3%
Distribution	3.5%	3.5%
Total Company	**3.0%**	**3.0%**

3. REGULATORY MATTERS

Regulatory Assets and Liabilities and Other Deferred Credits

Changes

The Tax Cuts and Jobs Act ("the Act") was enacted on December 22, 2017. Among other provisions, the Act reduces the corporate income tax rate from 35% to 21%. We began accruing the difference for our Arkansas customers effective January 2018. We implemented new rates related to this and started amortizing the regulatory liability in October 2018. There were no other changes to regulatory asset and liabilities with regard to their rate base inclusion or amortizable lives from December 31, 2017 to December 31, 2018.

The following table sets forth the components of our regulatory assets and regulatory liabilities on our consolidated balance sheets (in thousands).

	December 31, 2018	December 31, 2017
Regulatory Assets:		
Current:		
Under recovered fuel costs	$ 1,442	$ 6,231
Current portion of long-term regulatory assets	16,044	13,108
Regulatory assets, current	17,486	19,339
Long-term:		
Pension and other postemployment benefits	116,740	88,643
Income taxes	27,204	32,084
Deferred construction accounting costs(1)	13,986	14,344
Unamortized loss on reacquired debt	7,711	8,384
Under recovered fuel costs	6,049	8,419
Unsettled derivative losses – electric segment	800	2,133
System reliability – vegetation management	1,182	1,619
Storm costs(2)	1,913	2,448
Deferred operating and maintenance expense	8,442	5,053
Asset retirement obligation	21,048	16,080
Customer programs	5,689	6,052
Missouri solar initiative(3)	15,101	12,337
Deferred rate case expense	1,150	733
Current portion of long-term regulatory assets	(16,044)	(13,108)
Other	1,785	1,630
Regulatory assets, long-term	212,756	186,851
Total Regulatory Assets	**$ 230,242**	**$ 206,190**
Regulatory Liabilities		
Current:		
Over recovered fuel costs	$ 3,723	$ 1,427
Current portion of long-term regulatory liabilities	3,066	3,064
Regulatory liabilities, current	6,789	4,491
Long-term:		
Costs of removal(4)	105,882	99,007
SWPA payment for Ozark Beach lost generation	6,897	9,398
Income taxes(5)	210,175	204,076
Deferred construction accounting costs – fuel(6)	7,258	7,418
Unamortized gain on interest rate derivative	2,521	2,691
Pension and other postemployment benefits	6,885	5,131
Over recovered fuel costs	1,506	155
Current portion of long-term regulatory liabilities	(3,066)	(3,064)
Other	121	-
Regulatory liabilities, long-term	338,179	324,812
Total Regulatory Liabilities	**$ 344,968**	**$ 329,303**

(1) Reflects deferrals resulting from the 2005 regulatory plan relating to Iatan 1, Iatan 2 and Plum Point. These amounts are being recovered over the life of the plants.
(2) Reflects ice storm costs incurred in 2007 and costs incurred as a result of the May 2011 tornado including an accrued carrying charge and

deferred depreciation totaling $1.7 million at December 31, 2018.

(3) Resulting from the Missouri Clean Energy Initiative and consists of approximately 1,860 solar rebate applications processed as of December 31, 2018, resulting in solar rebate-related costs totaling approximately $16.2 million.

(4) As part of our depreciation rates, we accrue the estimated cost of dismantling and removing plant from service upon retirement and these costs are reflected here. See the depreciation discussion under Note 1 and Note 2 for more detail.

(5) The Tax Cuts and Jobs Act ("the Act") was enacted on December 22, 2017. Among other provisions, the Act reduces the corporate income tax rate from 35% to 21%. A reduction of regulatory asset and an increase to regulatory liability was recorded for excess deferred taxes probable of being refunded to customers of $151,485 and $143,428 for 2018 and 2017, respectively.

(6) Resulting from the regulatory plan requiring deferral of the fuel and purchased power impacts of Iatan 2.

Unamortized losses on debt and losses on interest rate derivatives are not included in rate base, but are included in our capital structure for rate base purposes. The remainder of our regulatory assets are not included in rate base, generally because they are not cash items. However, as of December 31, 2018, the costs of all of our regulatory assets are currently being recovered except for approximately $108.0 million of pension and other postemployment costs primarily related to the unfunded liabilities for future pension and OPEB costs. We expect recovery of the unfunded amount but the timing of the recovery will be based on the changing funded status of the pension and OPEB plans in future periods.

The regulatory income tax assets and liabilities are generally amortized over the average depreciable life of the related assets. The loss on reacquired debt and the loss and gain on interest rate derivatives are amortized over the life of the related new debt issue, which currently ranges from 1.4 to 26 years. The unrecovered fuel costs are generally recovered within a year following their recognition. Pension and OPEB tracking mechanisms are recovered over a five-year period. The cost of removal regulatory liability is amortized as removal costs are incurred.

RATE MATTERS

We routinely assess the need for rate relief in all of the jurisdictions we serve and file for such relief when necessary.

Our rates for retail electric, natural gas services and water (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are determined on a “cost of service” basis. Rates are designed to provide, after recovery of allowable operating expenses, an opportunity to earn a reasonable return on “rate base.” “Rate base” is generally determined by reference to the original cost (net of accumulated depreciation and amortization) of utility plant in service, subject to various adjustments for deferred taxes and other items. Over time, rate base is increased by additions to utility plant in service and reduced by depreciation, amortization and retirement of the utility plant or write-off as ordered by the utility commissions. In general, a request of new rates is made on the basis of a “rate base” as of test year end updated for certain pro-forma adjustments and allowable operating expenses for a 12-month test period ended. Although the current rate-making process provides recovery of some future changes in rate base and operating costs, it does not reflect all changes in costs for the period in which new retail rates will be in place. This results in a lag (commonly referred to as “regulatory lag”) between the time we incur costs and the time when we can start recovering the costs through rates.

The following table sets forth information regarding electric and water rate increases and decreases since January 1, 2017:

Jurisdiction	Date Requested	Annual Increase/ (Decrease) Granted	Percent Increase/ (Decrease) Granted	Date Effective
Oklahoma – Electric	December 21, 2016	$ 992,170	11.76%	August 31, 2017
Kansas – Electric	January 6, 2017	$ 958,186	4.83%	July 1, 2017
Missouri – Electric	June 6, 2018	($ 17,837,022)	(3.64%)	August 30, 2018
Arkansas – Electric	January 12, 2018	($ 482,817)	(5.24%)	October 1, 2018
Missouri – Gas	February 21, 2018	($ 773,566)	(3.49%)	October 24, 2018

Electric Segment

Missouri

2018 Rate Decrease: On August 15, 2018, the MPSC issued an order approving a rate decrease of approximately $17.8 million for our Missouri electric customers. This rate decrease, effective August 30, 2018, will remain in effect until new base rates incorporate the reduction in the corporate tax rate from 35% to 21% as a result of the federal Tax Cuts and Jobs Act of 2017.

Integrated Resource Plan and Missouri Energy Efficiency Investment Act

We filed our most recent Integrated Resource Plan (IRP) with the MPSC on April 1, 2016. The IRP analysis of future loads and resources is normally conducted once every three years and will be filed again on or before April 1, 2019.

On August 24, 2016, an Amended Stipulation and Agreement as to Division of Energy and Renew Missouri was filed in the Merger case in which we agreed to make a Missouri Energy Efficiency Investment Act (MEEIA) filing, provided a statewide Technical Reference Manual (TRM) has been approved by the state, and provided our next Triennial IRP (2019 or 2022, depending on the date a TRM is approved) favors a plan with increased demand-side management (DSM) investments. We will work with the Missouri Division of Energy (DE), the MPSC Staff, the Office of the Public Counsel (OPC) and other parties through the existing DSM Advisory Group to review and consider the viability of adopting additional energy efficiency programs for our customers. Within one year of the MPSC's finding of substantial compliance of the Empire IRP that follows MPSC approval of a TRM, we will develop and submit an application for approval of a portfolio of DSM programs under MEEIA, so long as any such portfolio is a part of our adopted preferred resource plan in our IRP, or has been analyzed through the integration process required and the portfolio and any DSM submitted in the application is fully compliant with the MEEIA statute and applicable regulations.

Kansas

2016 Rate Case: On September 16, 2016, we filed a request with the Kansas Corporation Commission (KCC) for changes in rates for our Kansas electric customers, seeking an annual increase in total revenue of approximately $6.4 million, or approximately 25.7%. On October 6, 2016, we announced the filing with the KCC of a Unanimous Settlement Agreement with respect to the joint application for approval of the Merger filed March 16, 2016, subject to approval by the KCC. As a condition of the Unanimous Settlement Agreement that was reached with the KCC staff, and approved by the KCC, our pending Kansas rate case was withdrawn and current base rates would remain in effect through at least January 1, 2019. The agreement also provided that we would file a request to update the current Environmental Recovery Rider in Kansas to include costs associated with the Riverton 12 Combined Cycle project, which would produce approximately $1.0 million of additional revenue annually.

On January 11, 2017, we filed a request to implement a rider, the Asbury Environmental and Riverton Rider (AERR), in place of the Asbury Environmental Rider (AER) that was currently in effect in our Kansas jurisdiction. The new rider provided a mechanism to begin recovering costs related to the $168 million combined cycle generating unit at the Riverton Power Plant. This rider was approved by the KCC with an effective date of July 1, 2017, resulting in an incremental revenue of approximately $958,186 annually.

2018 Rate Case: On December 19, 2018, we filed a request with the KCC for changes in rates for our Kansas electric customers, seeking an incremental increase in annual revenues of approximately $2.5 million, or approximately 15%.

2017 Ad Valorem Tax Surcharge:

On January 22, 2015, we filed an Application with the KCC requesting approval of our Ad Valorem Tax Surcharge (AVTS). The original request sought approval for an annual increase of $0.3 million related to increases in Ad Valorem taxes which exceed amounts currently included in base rates. The original request provided for an annual true-up calculation of the surcharge. On February 19, 2015, the KCC approved the request. The new rate was effective February 23, 2015. On January 31, 2018, we filed our annual true-up calculation with the KCC requesting approval for a revision to the AVTS. The request sought approval for an annual increase of an additional $0.5 million related to increases in Ad Valorem taxes which exceed amounts currently included in our AVTS rider. On March 1, 2018, the KCC approved the request. The new rate was effective March 1, 2018.

Oklahoma

On December 21, 2016, we filed a request with the OCC for changes in rates for our Oklahoma electric customers, seeking an increase in annual revenues of approximately $3.8 million, or approximately 27.58%. Primary drivers for this case include the $112 million Air Quality Control System (AQCS) at the Asbury Power Plant, the $168 million combined cycle generating unit at the Riverton Power Plant; upgrades to financial, asset, and work management software systems; and other reliability and system improvements to serve customers. On August 17, 2017, the OCC issued an Order authorizing an ECP Capital Investment Rider which serves to capture the environmental costs of the Asbury and Riverton 12 projects. This rider became effective on August 31, 2017 and is estimated to increase revenues annually approximately $1.0 million.

Arkansas

2018 Rate Decrease: On September 28, 2018, the APSC issued an order approving an annual rate decrease of approximately $0.5 million for our Arkansas electric customers. This rate decrease, effective October 1, 2018, reflects a reduction in the corporate tax rate from 35% to 21% resulting from the federal Tax Cuts and Jobs Act of 2017.

Customer Savings Plan

On October 31, 2017, The Empire District Electric Company filed with the MPSC, KCC, OCC, and the APSC an application requesting approval of a Customer Savings Plan that proposes to save customers $325 million over the next 20 years. The “Customer Savings Plan” is generally comprised of the acquisition or construction of up to 800-megawatts of wind generation facilities and the retirement of a coal generation facility and the associated establishment of a regulatory asset.

The MPSC issued an order on July 11, 2018 approving portions of the Customer Savings Plan. The MPSC has supported the addition of 600 MW of wind generation to be located within the Southwest Power Pool.

FERC

We have in place a cost-based transmission formula rate (TFR). On June 13, 2013, we, the KCC and the cities of Monett, Mt. Vernon and Lockwood, Missouri and Chetopa, Kansas, filed a unanimous Settlement Agreement (“the Agreement”) with the FERC. The Agreement included a TFR that would establish a return on equity (ROE) of 10.0%. The Agreement calls for the TFR to be updated annually with the new updated TFR rates effective on July 1 of each year. FERC conditionally approved the Agreement on November 18, 2013, and we made a compliance filing with FERC on December 18, 2013 in connection with this conditional approval. The FERC approved our compliance filing on June 12, 2014.

We have in place a cost-based generation formula rate (GFR). Our GFR requires an update to be completed annually for rates effective June 1. On October 29, 2014, Empire made a “limited” Section 205 filing to request some minor changes in the existing GFR formula to incorporate the impact of the recent implementation of the SPP IM. As a result of this filing, our customers’ share of the margins we receive from sales into the IM will be passed on to them through the monthly fuel and purchased power cost adjustment mechanism rather than making one-time adjustments at each annual update. This filing was approved by FERC on January 13, 2015.

Gas Segment

Missouri

2018 Rate Decrease: On October 17, 2018, the MPSC issued a notice approving an annual rate decrease of approximately $0.8 million for our Missouri gas customers. This rate decrease, effective October 24, 2018, reflects a reduction in the corporate tax rate from 35% to 21% resulting from the federal Tax Cuts and Jobs Act of 2017.

MARKETS AND TRANSMISSION

Electric Segment

Day Ahead Market: As part of the IM, Empire and other SPP market participants submit generation offers and demand bids for the sale and purchase of power into the SPP market. The SPP serves as a centralized commitment and dispatch of SPP members' generation resources while balancing economics and reliability. The SPP reports that approximately 95% of all next day generation needed throughout the SPP territory is being cleared through the IM. When we sell more generation to the market than we purchase for a given settlement period, the net sale is included as part of electric revenues. When we purchase more generation from the market than we sell, the net purchase is recorded as a component of fuel and purchased power on our consolidated financial statements. The net financial effect of these IM transactions is included in our fuel adjustment mechanisms and therefore has little impact on gross margin. We also acquire TCRs through annual and monthly processes in an attempt to mitigate congestion costs associated with the power we purchase from the IM. These rights are recorded as reductions to purchased power costs.

FERC Order No. 1000: In July 2011, the FERC issued Order No. 1000 (Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities) which requires all public utility transmission providers to allow transmission developers outside their retail distribution service territory to participate in regional transmission planning. As prescribed within the applicable amended SPP Open Access Transmission Tariff, Order No. 1000 eliminates the federal right of first refusal for entities that develop transmission projects within their own retail distribution service territories to construct new transmission facilities selected in a regional transmission plan which meet the criterion set forth in the amended tariff process. This order will directly affect our rights to build new 161kV and above transmission facilities within our retail service territory.

Order No. 1000 also directed transmission providers to develop policy and procedures for regional and interregional transmission planning as well as regional and interregional transmission cost allocation for approved transmission projects. We continue to participate in the SPP processes to understand the impact of these FERC orders on our ability to construct new facilities within our service territory as well as their influence on promoting construction of transmission projects on or near our borders with our neighbors. SPP completed and filed with the FERC a required interregional policy and procedure compliance filing, and while the FERC partially approved SPP's compliance filing, remaining issues have been addressed in a subsequent filing that is currently waiting FERC approval.

SPP/Midcontinent Independent System Operator (MISO) Joint Operating Agreement and Plum Point Delivery: Due to Plum Point's physical location and interconnection, transmission service from Entergy/MISO is required for delivery. On December 19, 2013, Entergy voluntarily integrated its generation, transmission, and load into the MISO regional transmission organization. Based on the current terms and conditions of MISO membership, Entergy's participation in MISO has increased transmission delivery costs for our Plum Point power station as well as utilized our transmission system without compensation.

As a result, we have participated with the SPP members and other impacted utilities in two separate FERC settlement proceedings in an effort to reduce the costs to our customers. On October 13, 2015, SPP members, SPP, MISO and MISO members filed a settlement at the FERC regarding MISO's unreserved and uncompensated use of the SPP members' systems. As approved by the FERC, the agreement provides compensation and governance for the continued shared use of the transmission system among MISO, SPP and other impacted utilities. The regional through and out transmission delivery rate (RTOR) dispute regarding Plum Point also proceeded through settlement discussions and a resulting settlement agreement was filed with the FERC on February 25, 2016. The settlement closed on June 23, 2016 and we withdrew all claims on July 6, 2016. We received a total of $2.1 million in MISO Through-and Out refunds in 2016 with rate reductions continuing through 2023-2025.

Gas Segment

Non-residential gas customers whose annual usage exceeds certain amounts may purchase natural gas from a source other than EDG. EDG does not have a non-regulated energy marketing service that sells natural gas in competition with outside sources. EDG continues to receive non-gas related revenues for distribution and other services if natural gas is purchased from another source by our eligible customers.

Other - Rate Matters

In accordance with ASC guidance on regulated operations, we currently have deferred approximately $1.2 million of expense related to rate cases in regulatory assets under other noncurrent assets and deferred charges. These amounts will be amortized over varying periods based upon the completion of the specific cases. Based on past history, we expect all these expenses to be recovered in rates.

4. STOCKHOLDER'S EQUITY

Employee Benefit Plans

Pursuant to the Merger, Empire employees are now participants in the APUC Employee Share Purchase Plan which allows eligible employees to use a portion of their earnings to purchase common shares of APUC.

Dividends

Beginning in 2017, the Board of Directors declares dividends, if any, to be paid to the parent company. The dividends paid in 2017 and 2018 were $32.0 million and $95.0 million, respectively.

On December 22, 2016, The Empire District Electric Company Board of Directors declared a special prorated dividend in the amount of $0.002857 per share, per day on the Company's outstanding common stock that accrued from December 1, 2016 until December 31, 2016, the day immediately preceding the Merger Closing Date. The special prorated dividend was equal to the daily equivalent of the then-current quarterly dividend rate of $0.26 per share, payable to stockholders of record on December 30, 2016. The special prorated dividend totaling approximately $3.9 million was accrued at December 31, 2016 and was paid on January 17, 2017.

The EDE Mortgage and our Restated Articles contain certain dividend restrictions. The most restrictive of these is contained in the EDE Mortgage, which provides that we may not declare or pay any dividends (other than dividends payable in shares of our common stock) or make any other distribution on, or purchase (other than with the proceeds of additional common stock financing) any shares of, our common stock if the cumulative aggregate amount thereof after August 31, 1944 (exclusive of the first quarterly dividend of $98,000 paid after said date) would exceed the sum of $10.75 million. The EDE Mortgage permits the payment of any dividend or distribution on, or purchase of, shares of our common stock within 60 days after the related date of declaration or notice of such dividend, distribution or purchase if (i) on the date of declaration or notice, such dividend, distribution or purchase would have complied with the provisions of the EDE Mortgage and (ii) as of the last day of the calendar month ended immediately preceding the date of such payment, our ratio of total indebtedness to total capitalization (after giving pro forma effect to the payment of such dividend, distribution, or purchase) was not more than 0.625 to 1.

5. LONG-TERM DEBT

At December 31, 2018 and 2017, the balance of long-term debt outstanding was as follows (in thousands):

	2018	2017
First mortgage bonds (EDE):		
6.375% Series due 2018 (1)	$ -	$ 90,000
4.65% Series due 2020 (1)	100,000	100,000
3.58% Series due 2027 (1)	88,000	88,000
3.59% Series due 2030 (1)	60,000	60,000
3.73% Series due 2033 (1)	30,000	30,000
5.875% Series due 2037 (1)	80,000	80,000
5.20% Series due 2040 (1)	50,000	50,000
4.32% Series due 2043 (1)	120,000	120,000
4.27% Series due 2044 (1)	60,000	60,000
First mortgage bonds (EDG):		
6.82% Series due 2036 (1)	55,000	55,000
	643,000	733,000
Senior Notes, 6.70% Series due 2033 (1)	62,000	62,000
Senior Notes, 5.80% Series due 2035 (1)	40,000	40,000
Promissory Note, 4.53% due June 1, 2033	90,000	
Capital lease obligations	2,864	3,208
Less unamortized debt expense	(7,192)	(7,316)
Less unamortized net discount	(479)	(529)
	830,193	830,363
Current unamortized debt expense	-	-
Less current obligations of long-term debt	-	-
Less current obligations under capital lease	(382)	(369)
TOTAL LONG-TERM DEBT	**$ 829,811**	**$ 829,994**

(1) We may redeem some or all of the notes at any time at 100% of their principal amount, plus a make-whole premium, plus accrued and unpaid interest to the redemption date.

EDE Mortgage Indenture

Substantially all of the property, plant and equipment of The Empire District Electric Company (but not its subsidiaries) is subject to the lien of the EDE Mortgage. Restrictions in the EDE mortgage bond indenture could affect our liquidity. The principal amount of all series of first mortgage bonds outstanding at any one time under the Indenture of Mortgage and Deed of Trust of The Empire District Electric Company (EDE Mortgage) is limited by terms of the mortgage to $1.0 billion. Based on the $1.0 billion limit, and our current level of outstanding first mortgage bonds, we are limited to the issuance of $412.0 million of new first mortgage bonds. The EDE Mortgage contains a requirement that for new first mortgage bonds to be issued, our net earnings (as defined in the EDE Mortgage) for any twelve consecutive months within the fifteen months preceding issuance must be two times the annual interest requirements (as defined in the EDE Mortgage) on all first mortgage bonds then outstanding and on the prospective issue of new first mortgage bonds. In addition to the interest coverage requirement, the EDE Mortgage provides that new bonds must be issued against, among other things, retired bonds or 60% of net property additions. The annual interest coverage requirement and retired bonds or 60% of net property additions test would permit the issuance of more than $412.0 million of first mortgage bonds; however, as discussed above, we are otherwise limited to the issuance of no more than $412.0 million of new first mortgage bonds. As of December 31, 2018, we are in compliance with all restrictive covenants of the EDE Mortgage.

On June 1, 2018, EDE's $90 million 6.375% Series first mortgage bonds matured and were repaid with the proceeds of a promissory note of like amount issued to Liberty Utilities Co. The Liberty Utilities Co. promissory note carries a fixed rate of

4.53% and matures on June 1, 2033.

EDG Mortgage Indenture

The principal amount of all series of first mortgage bonds outstanding at any one time under the Indenture of Mortgage and Deed of Trust of The Empire District Gas Company (EDG Mortgage) is limited by terms of the mortgage to $300.0 million. Substantially all of the property, plant and equipment of EDG is subject to the lien of the EDG Mortgage. The EDG Mortgage contains a requirement that for new first mortgage bonds to be issued, the amount of such new first mortgage bonds shall not exceed 75% of the cost of property additions acquired after the date of the Missouri Gas acquisition. The mortgage also contains a limitation on the issuance by EDG of debt (including first mortgage bonds, but excluding short-term debt incurred in the ordinary course under working capital facilities) unless, after giving effect to such issuance, EDG's ratio of EBITDA (defined as net income plus interest, taxes, depreciation, amortization and certain other non-cash charges) to interest charges for the most recent four fiscal quarters is at least 2.0 to 1.0. As of December 31, 2018, this test would allow us to issue approximately $6.3 million principal amount of new first mortgage bonds at an assumed interest rate of 5.5%. As of December 31, 2018, we are in compliance with all restrictive covenants of the EDG Mortgage.

Our long-term debt obligations over the next five years are as follows (in thousands):

	Payments Due By Period		
Long-Term Debt Payout Schedule (Excluding Unamortized Discount) (in thousands)	**Total**	**Regulated Entity Debt Obligations**	**Capital Lease Obligations**
2019	$ 366	$ -	$ 366
2020	100,387	100,000	387
2021	413	-	413
2022	441	-	441
2023	470	-	470
Thereafter	735,787	735,000	787
Total long-term debt obligations	**837,864**	**$ 835,000**	**$ 2,864**
Less current obligations and unamortized discount	8,053		
TOTAL LONG-TERM DEBT	**$ 829,811**		

6. SHORT-TERM BORROWINGS

At December 31, 2018, total short-term borrowings consisted of $6 million in commercial paper which is supported by the Liberty Utilities Credit Facility (see below). During 2018 and 2017, our short-term borrowings outstanding averaged (in millions):

	2018	**2017**
Average borrowings outstanding	$ 5.5	$10.1
Highest month end balance	$21.8	$40.3

The weighted average interest rates and the weighted average interest rate of borrowings outstanding at December 31, 2018 and 2017 were:

	2018	**2017**
Weighted average interest rate	1.97%	1.14%
Weighted average interest rate of borrowings outstanding	2.84%	1.85%

Effective February 23, 2018, our $200 million 5-year Credit Agreement, which was set to expire in October 2019, was terminated. Empire maintained its commercial paper program but the program is supported by a credit facility maintained by its parent company, Liberty Utilities Co. On February 23, 2018, Liberty Utilities Co. entered into a new 5-year $500 million credit facility ("Liberty Utilities Credit Facility") which is available to Liberty for, among other things, working capital and general corporate purposes, including supporting the working capital needs of its subsidiaries.

The former Empire credit facility required our total indebtedness to be less than 65.0% of our total capitalization at the end of each fiscal quarter and a failure to maintain this ratio would result in an event of default under the credit facility and would have prohibited us from borrowing funds thereunder. As of December 31, 2017, we were in compliance with this covenant as our total indebtedness to total capitalization was 50.3%. The credit facility was also subject to cross-default if we default on more than $25 million in the aggregate on our other indebtedness. As of December 31, 2017, we were not in default under any of our debt obligations. The aforementioned requirements are no longer applicable after February 23, 2018.

The former credit agreement did not legally restrict the use of our cash in the normal course of operations. There were no outstanding borrowings under the agreement at December 31, 2017; however, $5.6 million was used to back up our outstanding commercial paper.

7. RETIREMENT AND OTHER EMPLOYEE BENEFITS

We record retirement benefits in accordance with the ASC guidance on accounting for pension and other postemployment benefits, and have recorded the appropriate liabilities to reflect the unfunded status of our benefit plans, with offsetting entries to a regulatory asset, because we believe it is probable the unfunded amount of these plans will be afforded rate recovery. Additionally, the MPSC agreed that the effects of purchase accounting entries related to pension and other post-retirement benefits would be recoverable in future rate proceedings. These amounts, which are recorded as regulatory assets, are being amortized. The tax effects of these entries are reflected as deferred tax assets and liabilities and regulatory liabilities.

Annually, we evaluate the discount rate, retirement age, compensation rate increases, expected return on plan assets, healthcare cost trend rate, and other actuarial assumptions related to the pension benefit and post-retirement medical plan. When selecting the discount rate we utilize a modeling process that involves selecting a portfolio of above median, AA or better, bonds whose cash flows match the timing and extent of the expected cash flows of the Empire pension plan. In evaluating these assumptions, many factors are considered, including, current market conditions, asset allocations, changes in demographics and the views of leading financial advisors and economists. In evaluating the expected retirement age assumption, we consider the retirement ages of past employees eligible for pension and medical benefits together with expectations of future retirement ages. It is reasonably possible that changes in these assumptions will occur in the near term and, due to the uncertainties inherent in setting assumptions, the effect of such changes could be material to the Company's consolidated financial statements. A roll forward technique is used to value the year ending pension obligations. The roll forward technique values the year-end obligation by rolling forward the beginning-of-year obligation using the demographic assumptions disclosed below. The economic assumptions are updated as of the end of the year. All of the benefit plans have been measured as of December 31, 2018, consistent with previous years. See Note 1.

Pensions

Our noncontributory defined benefit pension plan includes all employees meeting minimum age and service requirements. Employees hired on or after January 1, 2014 accrue benefits based on a cash balance methodology. Employees hired prior to January 1, 2014 were given a one-time option to convert to the cash balance methodology, or remain with our traditional average annual basic earnings formula, by December 31, 2014. Both benefit formulas allow for a lump-sum distribution of vested benefits. Lump-sum distributions totaled approximately $29.1 million and $25.4 million during 2018 and 2017, respectively. In 2018, lump-sum distributions required settlement accounting according to ASC 715, and resulted in a settlement loss of approximately $2.5 million.

Annual contributions to the plan are at least equal to the greater of either minimum funding requirements of ERISA or the accrued cost of the plan, as required by the MPSC.

Our net pension liability increased $18.0 million in 2018, which was recorded as an increase in regulatory assets as we believe it is probable of recovery through customer rates based on rate orders received in our jurisdictions. Our contribution is estimated to be approximately $10.2 million for 2019. We expect future pension funding commitments to continue at least at the level of our accrued cost, as required by our regulator. The actual minimum funding requirements will be determined based on the results of the actuarial valuations and, in the case of 2020, the performance of our pension assets during 2019.

We also have a supplemental retirement program ("SERP") for designated former officers of the Company, which we fund from Company funds as the benefits are paid. The liability for this plan decreased $1.3 million in 2018. Subsequent to the closing of the Merger, the SERP plan was frozen. See Note 15 for further discussion of the Merger Agreement.
Expected benefit payments are as follows (in millions):

Year	Payments from Trust	Payments from Company Funds
2019	$ 13.7	$ 0.5
2020	14.4	0.6
2021	15.4	0.9
2022	16.3	0.9
2023	17.1	0.9
2024-2028	89.8	4.4

Other Postemployment Benefits (OPEB)

We provide certain healthcare and life insurance benefits to eligible retired employees, their dependents and survivors through trusts we have established. Participants generally become eligible for retiree healthcare benefits after reaching age 55 with 5 years of service. Employees hired after January 1, 2014 will be offered unsubsidized retiree healthcare benefits upon retirement.

Our net liability increased $15.8 million in 2018, which was recorded as an increase in regulatory assets as we believe it is probable of recovery through customer rates based on rate orders received in our jurisdictions. Our funding policy is to contribute annually an amount at least equal to the actuarial cost of postemployment benefits. We expect to be required to fund approximately $3.25 million in 2019.

Estimated benefit payments are as follows (in millions):

Year	Payments from Trust
2019	$ 3.6
2020	3.9
2021	4.2
2022	4.5
2023	4.8
2024-2028	28.9

The following tables set forth the Company's benefit plans' projected benefit obligations, the fair value of the plans' assets and the funded status (in thousands).

Reconciliation of Projected Benefit Obligations:	Pension		SERP		OPEB	
	2018	2017	2018	2017	2018	2017
Benefit obligation at beginning of year	$ 243,254	$ 245,146	$ 15,091	$ 11,340	$ 110,075	$ 97,761
Service cost	8,473	7,767	-	-	3,525	2,668
Interest cost	8,893	9,836	524	555	4,331	4,166
Net actuarial (gain)/loss	(5,086)	14,449	(1,285)	3,617	(1,446)	7,773
Plan participant's contribution	-	-	-	-	1,431	1,251
Benefits and expenses paid	(37,640)	(33,944)	(519)	(421)	(5,776)	(3,678)
Federal subsidy	-	-	-	-	42	134
Benefit obligation at end of year	**$217,894**	**$243,254**	**$ 13,811**	**$ 15,091**	**$ 112,182**	**$ 110,075**

Reconciliation of Fair Value of Plan Assets:	**Pension**		**SERP**		**OPEB**	
	2018	**2017**	**2018**	**2017**	**2018**	**2017**
Fair value of plan assets at beginning of year	$ 196,833	$ 184,509	$ -	$ -	$ 106,699	$ 91,532
Actual return on plan assets – gain/(loss)	(18,169)	32,068	-	-	(9,369)	16,677
Employer contribution	12,448	14,200	519	421	-	784
Benefits paid	(37,640)	(33,944)	(519)	(421)	(5,776)	(3,678)
Plan participant's contribution	-	-	-	-	1,431	1,251
Federal subsidy	-	-	-	-	42	134
Fair value of plan assets at end of year	**$ 153,472**	**$ 196,833**	**$ -**	**$ -**	**$ 93,027**	**$ 106,700**

Reconciliation of Funded Status:	**Pension**		**SERP**		**OPEB**	
	2018	**2017**	**2018**	**2017**	**2018**	**2017**
Fair value of plan assets	$153,472	$196,833	$ -	$ -	$ 93,027	$ 106,700
Projected benefit obligations	(217,894)	(243,254)	(13,811)	(15,091)	(112,182)	(110,075)
Funded status	**$(64,422)**	**$(46,421)**	**$(13,811)**	**$(15,091)**	**$ (19,155)**	**$ (3,375)**

The employee pension plan accumulated benefit obligation at December 31, 2018 and 2017 is presented in the following table (in thousands):

	Pension Benefits		**SERP**	
	2018	**2017**	**2018**	**2017**
Accumulated benefit obligation	$190,220	$220,362	$ 13,811	$ 15,091

Amounts recognized in the consolidated balance sheets consist of the following (in thousands):

	Pension		**SERP**		**OPEB**	
	2018	**2017**	**2018**	**2017**	**2018**	**2017**
Other deferred charges	$ -	$ -	$ -	$ -	$ -	$ 809
Accounts payable and accrued liabilities	$ -	$ -	$ 513	$ 513	$ -	$ -
Pension and other postemployment benefit obligations	$ 64,422	$ 46,421	$ 13,298	$ 14,578	$ 19,155	$ 4,184

Net periodic benefit pension cost for 2018 and 2017, some of which is capitalized as a component of labor cost and some of which is deferred as a regulatory asset (See Note 3), is comprised of the following components (in thousands):

Net Periodic Pension Benefit Cost:	**Pension**		**OPEB**		**SERP**	
	2018	**2017**	**2018**	**2017**	**2018**	**2017**
Service cost	$ 8,473	$ 7,767	$ 3,525	$ 2,668	$ -	$ -
Interest cost	8,893	9,836	4,331	4,166	524	555
Expected return on plan assets	(13,630)	(12,368)	(6,309)	(5,389)	-	-
Amortization of prior service cost/(benefit)[1]	-	-	-	-	-	-
Amortization of actuarial loss[1]	357	-	-	-	359	-
Net periodic benefit cost	**$ 4,093**	**$ 5,235**	**$ 1,547**	**$ 1,445**	**$ 883**	**$ 555**

[1]Amounts are amortized from our regulatory asset originally recorded upon recognizing our net pension liability on the consolidated balance sheets.

The table below presents other changes in plan assets and benefit obligations recognized in the regulatory asset accounts for the year (in thousands):

		Amount Recognized			
Regulatory Assets	**Beginning Balance 12/31/17**	**Current Year Actuarial (Gain)/Loss**	**Amortization of Actuarial Gain**	**Amortization of Prior Service (Cost)/Credit**	**Ending Balance 12/31/18**
Pension	$ 82,015	26,713	(2,904) (1)		$ 105,824
SERP	$ 9,818	(1,285)	(359)		$ 8,174
OPEB	$ (2,747)	14,232	-		$ 11,485

(1) Amount includes $2,547 loss due to plan settlement.

The measurement date used to determine the pension and other postemployment benefits is December 31. The assumptions used to determine the benefit obligation and the periodic costs are as follows:

Weighted-average Assumptions Used to Determine the Benefit Obligation as of December 31:

	Pension Benefits		OPEB	
	2018	**2017**	**2018**	**2017**
Discount rate	4.22%	3.54%	4.28%	3.63%
Rate of compensation increase	4.00%	3.00%	4.00%	3.00%

Weighted-average Assumptions used to Determine the Net Benefit Cost (Income) as of January 1:

	Pension Benefits		OPEB	
	2018	**2017**	**2018**	**2017**
Discount rate	3.54%	4.09%	3.63%	4.19%
Expected return on plan assets	7.25%	7.00%	6.75%	6.75%
Rate of compensation increase	4.00%	3.00%	3.00%	3.00%

The expected long-term rate of return assumption was based on historical return and adjusted to estimate the potential range of returns for the current asset allocation. The assumed 2018 cost trend rate used to measure the expected cost of healthcare benefits and benefit obligation is 6.25%. Each trend rate decreases 0.125% through 2031 to an ultimate rate of 4.75% in 2031 and subsequent years.

The healthcare cost trend rate affects projected benefit obligations. A 1% change in assumed healthcare cost growth rates would have the following effects (in thousands):

	1% Increase	1% Decrease
Effect on total of service and interest cost	$ 1,884	$ (1,416)
Effect on post-retirement benefit obligation	$ 20,515	$ (16,137)

Fair Value Measurements of Plan Assets

See Note 13 for a discussion of fair value measurements. The Company believes that it is appropriate for the pension fund to assume a moderate degree of investment risk with diversification of fund assets among different classes (or types) of investments, as appropriate, as a means of reducing risk. Although the pension fund can and will tolerate some variability in market value and rates of return in order to achieve a greater long-term rate of return, primary emphasis is placed on preserving the pension fund's principal. Full discretion is delegated to the investment managers to carry out investment policy within stated guidelines. The guidelines and performance of the managers are monitored by the Company's Investment Committee. The following is a description of the valuation methodologies used for assets measured at fair value using significant other observable, or significant unobservable inputs.

Short-term investments: Valued at cost, which approximates fair value.

Common/Collective trusts: Valued at the fair value based on audited financials of the trusts.

U.S. corporate and foreign issue debt: Valued at quoted market prices when available in an active market. If quoted market prices are not available, then fair values are estimated by using pricing models, quoted prices of securities with similar characteristics, or discounted cash flows.

Equity long/short hedge funds: Valued at the net asset value reported in the annual audited financial statements and updated monthly based on changes in the value of the underlying funds reported by the fund manager.

Plan Assets

We utilize fair value in determining the market-related values for the different classes of our pension plan assets. The market-related value is determined based on smoothing actual asset returns in excess of (or less than) expected return on assets over a 5-year period.

The Company's investment strategy for its pension plan assets is to maintain a diversified portfolio of assets with the primary goal of meeting long-term cash requirements as they become due.

Asset Allocation

Asset Class	Target (%)	Range (%)
Equity securities	78%	49% - 78%
Debt securities	22%	22% - 51%

Pension Plan Assets

The following fair value hierarchy table presents information about the pension fund assets measured at fair value as of December 31, 2018 and December 31, 2017 (in thousands):

	Fair Value Measurements as of December 31, 2018				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	**Significant Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**	**Percentage of Plan Assets**
Equity Securities	$ 119,094	$ -	$ -	$ 119,094	77.6%
Debt Securities	34,378	-	-	34,378	22.4 %
	$ 153,472	**$**	**$ -**	**$ 153,472**	**100.0%**

Fair Value Measurements as of December 31, 2017

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Percentage of Plan Assets
Common stock	$ 14,566	$ -	$ -	$ 14,566	7.4%
Mutual funds					
Domestic equity	52,161	-	-	52,161	26.5%
International equity	57,868	-	-	57,868	29.4%
Lifestyle funds	14,369	-	-	14,369	7.3%
Fixed income					
Mutual funds	42,713	-	-	42,713	21.7%
Private placement	-	15,156		15,156	7.7%
	$ 181,677	**$ 15,156**	**$ -**	**$ 196,833**	**100.0%**

Fair Value Measurements Using Significant Unobservable Inputs (Level 3) – December 31,

	2018 Equity long/short hedge funds	2017 Equity long/short hedge funds
Beginning Balance, January 1	$ -	$ 1,834
Actual return on plan assets:		
Relating to assets still held at the reporting date	-	-
Relating to assets sold during the period	-	-
Purchases	-	-
Sales	-	-
Settlements		(1,834)
Transfers into and (out of) Level 3	-	-
Ending Balance, December 31	**$ -**	**$ -**

OPEB plan assets

The following fair value hierarchy table presents information about the OPEB fund assets measured at fair value as of December 31, 2018 and December 31, 2017 (in thousands):

Fair Value Measurements as of December 31, 2018

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Percentage of Plan Assets
Equity Securities	$ 72,189	$ -	$ -	$ 72,189	77.6%
Debt Securities	20,838	-	-	20,838	22.4%
	$ 93,027	**$ -**	**$ -**	**$ 93,027**	**100.0%**

Fair Value Measurements as of December 31, 2017

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Percentage of Plan Assets
Cash	$ 829	$ -	$ -	$ 829	0.8%
Mutual funds					
Fixed income	22,291	-	-	22,291	20.9%
Domestic equity	36,196	-	-	36,196	33.9%
International equity	47,384	-	-	47,384	44.4%
	$ 106,700	**$ -**	**$ -**	**$ 106,700**	**100.0%**

401(k) Plan and ESOP

Our Employee 401(k) Plan and ESOP (the 401(k) Plan) allows participating employees to defer up to 25% of their annual compensation up to an Internal Revenue Service specified limit. For employees participating in the cash balance formula of the pension plan, discussed above, we match 100% of their deferrals, not to exceed 6% of the employee's eligible compensation. We record the compensation expense at the time the matching contributions are made to the plan. Subsequent to the Merger, as part of the APUC 401(k) Plan, matching employer contributions are made in cash.

8. EQUITY COMPENSATION

Prior to the closing of the Merger, we maintained several stock-based awards and programs. Performance-based restricted stock awards and time-vested restricted stock were valued as liability awards, in accordance with fair value guidelines. We allowed employees to elect to have taxes in excess of the minimum statutory requirements withheld from their awards and, therefore, the awards were classified as liability instruments under the ASC guidance on share-based payment. Awards treated as liability instruments must be revalued each period until settled, and cost is accrued over the requisite service period and adjusted to fair value at each reporting period until settlement or expiration of the award. Pursuant to the merger, the stock incentive plans underlying the stock-based awards and programs were terminated on January 1, 2017. See Note 15.

We recognized the following amounts in compensation expense and tax benefits for all of our stock-based awards and programs for the applicable years ended December 31 (in thousands):

	2018	2017
Compensation expense	$ 2,234	$ 1,899
Tax benefit recognized	546	723

Algonquin offers a Performance Stock Unit (PSU) plan to officers and directors as part of its long-term incentive program. PSUs are granted annually for three-year overlapping performance cycles. PSUs vest at the end of the three-year cycle and will be calculated based on established performance criteria. At the end of the three-year performance periods, the number of common shares issued can range from 2% to 237% of the number of PSUs granted. Dividends accumulating during the vesting period are converted to PSUs based on the market value of the shares on that date and are recorded in equity as the dividends are declared. None of these PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire. The PSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards.

Compensation expense associated with PSUs is recognized rateably over the performance period. Achievement of the performance criteria is estimated at the consolidated balance sheet date. Compensation cost recognized is adjusted to reflect the performance conditions estimated to-date. Our compensation expense for 2018 was $0.5 million.

9. INCOME TAXES

Income tax expense components for the years ended December 31 are as follows (in thousands):

	2018	2017
Current income taxes:		
Federal	$ 25,017	$ (188)
State	(375)	2,494
TOTAL	24,642	2,306
Deferred income taxes:		
Federal	(6,031)	48,261
State	(859)	6,874
TOTAL	(6,890)	55,135
Investment tax credit amortization	-	(143)
TOTAL INCOME TAX EXPENSE	**$ 17,752**	**$ 57,298**

Deferred Income Taxes

Deferred tax assets and liabilities are reflected on our consolidated balance sheets as follows (in thousands):

	December 31,	
Deferred Income Taxes	**2018**	**2017**
NET DEFERRED TAX LIABILITIES	$ 259,844	$ 277,013

Temporary differences related to deferred tax assets and deferred tax liabilities are summarized as follows (in thousands):

	December 31,	
Temporary Differences	**2018**	**2017**
Deferred tax assets:		
Plant related basis differences	$ 18,846	$ 20,457
Net operating loss (NOL)	-	-
Regulated liabilities related to income taxes	57,989	62,176
Disallowed plant costs	889	1,340
Gains on hedging transactions	705	718
Carry forward of income tax credit	-	1,808
Other	(509)	1,454
Total deferred tax assets	$ 77,920	$ 87,953
Deferred tax liabilities:		
Depreciation, amortization and other plant-related differences	$ 289,198	$ 305,501
Regulated assets related to income	22,429	26,868
Loss on reacquired debt	1,719	2,059
Amortization of intangible assets	8,855	8,272
Pensions and other post-retirement benefits	3,192	5,043
Deferred construction accounting costs	2,654	3,632
Other	9,717	13,591
Total deferred tax liabilities	337,764	364,966
NET DEFERRED TAX LIABILITIES	**$ 259,844**	**$ 277,013**

Effective Income Tax Rates

The difference between income taxes and amounts calculated by applying the federal legal rate to income tax expense for continuing operations were as follows:

Effective Income Tax Rates	2018	2017
Federal statutory income tax rate	21.0%	35.0%
Increase (decrease) in income tax rate resulting from:		
State income tax (net of federal benefit)	3.5	3.1
Investment tax credit amortization	(0.3)	(0.4)
Effect of rate-making on property related differences	0.2	2.5
Federal and state income tax rate reductions	0.1	(7.0)
Transaction-related costs and other deferred tax adjustments	(12.7)	26.9
Other	0.2	0.8
EFFECTIVE INCOME TAX RATE	**12.0%**	**60.9%**

Our effective income tax rates for 2018 were driven by the impacts of U.S. federal and Missouri state income tax rate reductions discussed further below, and other related deferred tax adjustments.

We do not have any unrecognized tax benefits as of December 31, 2018. We did not recognize any significant interest or penalties in any of the periods presented. We do not expect any significant changes to our unrecognized tax benefits over the next twelve months.

Tax information included in these consolidated financial statements reflects the results of operations of the Empire District companies on a standalone basis. Upon our acquisition on January 1, 2017, we joined the Liberty Utilities consolidated group for filing federal and state income tax returns. As such, Empire’s current income and carried forward tax attributes were combined with those of the other Liberty Utilities companies. The liability for current income taxes is carried in “Taxes accrued” on the balance sheet for standalone statement presentation. This liability will be resolved by intercompany payment to Liberty Utilities rather than by direct payment to tax jurisdictions. Of the $28.7 million in Taxes accrued, approximately $25 million relates to Empire’s stand-alone income tax liability.

At the beginning of 2017, we had a net operating loss (NOL) carryforward of $44.4 million. During 2017, on a standalone basis, we generated an additional $6.2 million NOL carryforward from our pre-acquisition period and consumed $38.8 million of the NOL carryforward in our post-acquisition period. During 2018, we identified adjustments to taxable income in prior years which increased the NOL carryforward by $26.5 million. The resulting $38.3 million NOL carryforward was consumed in 2018.

In 2010, we received $17.7 million of investment tax credits based on our investment in Iatan 2, which, if unused, will expire in 2030. We utilized $10.4 million of these credits in the 2013 tax year. In 2018, on a standalone basis, we utilized the remaining $7.3 million of the credits. The tax credits will have no significant income statement impact because they will flow to our customers as we amortize the tax credits over the life of the plant.

Federal Tax Reform

The “Tax Cuts and Jobs Act” (TCJA) was enacted on December 22, 2017. Substantially all of the provisions of the TCJA affecting the Company, other than certain transition depreciation rules, are effective for taxable years beginning after December 31, 2017. The TCJA includes significant changes to the Internal Revenue Code, including amendments that significantly change the taxation of business entities and specific provisions related to regulated public utilities. The most significant change that affects the Company is the reduction in the federal corporate statutory income tax rate from 35% to 21%. Specific provisions related to regulated public utilities generally allow for the continued deductibility of interest expense, the elimination of accelerated depreciation tax benefits from certain regulated utility capital investments acquired after September 27, 2017, and the continuation of certain rate normalization requirements related to the flow back of excess deferred taxes.

In accordance with GAAP, the tax effects of changes in tax laws must be recognized in the period in which the law is enacted. GAAP also requires deferred tax assets and liabilities to be measured at the tax rate that is expected to apply when temporary differences are realized or settled. Thus, in December 2017, the Company's deferred taxes were revalued using the new tax rate. To the extent deferred tax balances are included in rate base, the revaluation of deferred taxes was deferred as a regulatory liability on the consolidated balance sheets and will be refunded to customers. For deferred tax balances not included in rate base, the revaluation of deferred taxes was recorded as income tax expense. As of December 31, 2017, the Company estimated the impact of TCJA to be a decrease in accumulated deferred income taxes $214.2 million, creation of a noncurrent regulatory liability of $193.0 million, and recognition of an income tax benefit of $5.9 million. During the year ended December 31, 2018, we reduced the regulatory liability by $7.0 million associated with TCJA items. A majority of the excess deferred taxes are related to the depreciable lives and methods associated with Plant assets and will be amortized under the Average Rate Assumption Method (ARAM) as prescribed by the Internal Revenue Code. The portion that was eligible for amortization in 2018, but is awaiting resolution of the treatment of these amounts in future regulatory proceedings, has not been recognized and may be refunded in customer rates at any time in accordance with the resolution of pending or future regulatory proceedings. Other components of the excess deferred taxes will be reflected in customer rates as determined by our state and federal regulators, which could be a shorter time period than that applicable to certain plant-related components.

On June 1, 2018, the state of Missouri enacted legislation lowering its corporate income tax rate to 4%, effective January 1, 2020. As with TCJA, this change creates an obligation to refund excess deferred income taxes to customers. During the year ended December 31, 2018, the Company reduced accumulated deferred income taxes by $15.2 million, recognized a regulatory liability of $14.6 million, and recorded a tax benefit of $0.6 million.

10. COMMONLY OWNED FACILITIES

Iatan

We own a 12% undivided interest in the coal-fired Units No. 1 and No. 2 at the Iatan Generating Station located near Weston, Missouri, 35 miles northwest of Kansas City, Missouri, as well as a 3% interest in the site and a 12% interest in certain common facilities. We are entitled to 12% of each unit's available capacity and are obligated to pay for a like percentage of the operating costs of the units. KCP&L and KCP&L Greater Missouri Operations Co. own 70% and 18% respectively, of Unit 1, and 54% and 18%, respectively, of Unit 2. KCP&L operates the units for the joint owners.

At December 31, 2018 and 2017, our property, plant and equipment accounts included the amounts in the following chart (in millions):

Iatan	2018	2017
Cost of ownership in plant in service	$ 400.0	$ 391.3
Accumulated depreciation	$ 122.9	$ 116.8
Expenditures(1)	$ 24.8	$ 28.8

(1) Recognized in operating, maintenance, and fuel expenditures excluding depreciation expense.

State Line Combined Cycle Unit

We share joint ownership with Westar Generating, Inc, (WGI), a subsidiary of Westar Energy, Inc., of a nominal 500-megawatt combined cycle unit at the State Line Power Plant (State Line Combined Cycle Unit). We are responsible for the operation and maintenance of the State Line Combined Cycle Unit, and are entitled to 60% of the available capacity and are responsible for approximately 60% of its costs.

At December 31, 2018 and 2017, our property, plant and equipment accounts included the amounts in the following chart (in millions):

State Line Combined Cycle Unit	2018	2017
Cost of ownership in plant in service	$ 207.6	$ 163.5
Accumulated depreciation	$ 71.0	$ 47.5
Expenditures(1)	$ 40.6	$ 41.8

(1) Recognized in operating, maintenance, and fuel expenditures excluding depreciation expense.

Plum Point Energy Station

We own a 7.52% undivided interest in the coal-fired Plum Point Energy Station located near Osceola, Arkansas. We are entitled to 7.52% of the station's capacity, and are obligated to pay for a like percentage of the station's operating costs.

At December 31, 2018 and 2017, our property, plant and equipment accounts included the amounts in the following chart (in millions):

Plum Point Energy Station	2018	2017
Cost of ownership in plant in service	$ 109.6	$ 109.7
Accumulated depreciation	$ 19.4	$ 15.0
Expenditures(1)	$ 10.1	$ 9.1

(1) Recognized in operating, maintenance and fuel expenditures excluding depreciation expense.

All of the dollar amounts listed above represent our ownership share of costs.

11. COMMITMENTS AND CONTINGENCIES

We are a party to various claims and legal proceedings arising out of the normal course of our business. We regularly analyze this information, and provide accruals for any liabilities, in accordance with the guidelines presented in the ASC on accounting for contingencies. In the opinion of management, it is not probable, given the Company's defenses, that the ultimate outcome of these claims and lawsuits will have a material adverse effect upon our financial condition, or results of operations or cash flows.

Coal, Natural Gas and Transportation Contracts

The following table sets forth our firm physical gas, coal and transportation contracts for the periods indicated as of December 31, 2018 (in millions):

	Firm physical gas and transportation contracts	Coal and coal transportation contracts
January 1, 2019 through December 31, 2019	$ 27.2	$ 3.1
January 1, 2020 through December 31, 2021	31.1	-
January 1, 2022 through December 31, 2023	28.4	-
January 1, 2024 and beyond	18.9	-

We have entered into long and short-term agreements to purchase coal and natural gas for our energy supply and natural gas operations. Under these contracts, the natural gas supplies are divided into firm physical commitments and derivatives that are used to hedge future purchases. The firm physical gas and transportation commitments are detailed in the table above.

We have coal supply agreements and transportation contracts in place to provide for the delivery of coal to the plants. These contracts are written with Force Majeure clauses that enable us to reduce tonnages or cease shipments under certain circumstances or events. These include mechanical or electrical maintenance items, acts of God, war or insurrection, strikes, weather and other disrupting events. This reduces the risk we have for not taking the minimum requirements of fuel under the contracts. The minimum requirements for our coal and coal transportation contracts as of December 31, 2018 are detailed in the table above. Our existing railroad agreement was modified and became effective on October 1, 2016. Our contractual obligations, as reflected in the table above, were reduced as a result of the amendment. The amended terms continue to allow us to operate the Asbury plant up to full load capacity.

Purchased Power

We have three purchased power agreements.

The Plum Point Energy Station (Plum Point) is a 670-megawatt, coal-fired generating facility near Osceola, Arkansas. We own, through an undivided interest, 50 megawatts of the unit's capacity. We also have a long-term agreement for the purchase of an additional 50 megawatts of capacity from Plum Point. Commitments under this agreement are approximately $246.8 million through August 31, 2039, the end date of the agreement.

We have a long-term purchased power agreement, which expires in 2028, with Cloud County Windfarm, LLC, owned by EDP Renewables North America LLC, Houston, Texas to purchase the energy generated at the approximately 105-megawatt Phase 1 Meridian Way Wind Farm located in Cloud County, Kansas. Annual payments are contingent upon output of the facility and can range from zero to a maximum of approximately $14.6 million based on a 20-year average cost.

We also have a long-term contract, which expires in 2025, with Elk River Windfarm, LLC, owned by IBERDROLA RENEWABLES, Inc., to purchase the energy generated at the 150-megawatt Elk River Windfarm located in Butler County, Kansas. Annual payments are contingent upon output of the facility and can range from zero to a maximum of approximately $16.9 million based on a 20-year average cost.

We do not own any portion of these windfarms. Payments for these agreements are recorded as purchased power expenses, and, because of the contingent nature of these payments, are not included in the operating lease obligations shown below.

Leases

We have purchased power agreements with Cloud County Windfarm, LLC and Elk River Windfarm, LLC, which are considered operating leases for GAAP purposes. Details of these agreements are disclosed in the Purchased Power section of this note.

We also currently have short-term operating leases for one unit train to meet coal delivery demand for our electric segment and for one office facility related to our gas segment. The electric segment has 107 land leases for future wind project facilities that are for a seven-year lease term during the development period of the project, after which there are renewal terms at higher rates for sites that are developed. There are 21 lease options for future wind project facilities that are for a three-year lease term that the Company has the right to terminate at any time. There are also 63 transmission easement option agreements that are a four year option, which at the Company's discretion can be exercised and become a perpetual transmission easement and the Company has the right to terminate at any time. The leases related to future wind project facilities have been assigned to Tenaska as of January 4, 2019. In addition, we have capital leases for certain office equipment and 106 railcars to provide coal delivery for our ownership and purchased power agreement shares of the Plum Point generating facility.

The gross amount of assets recorded under capital leases totaled $5.2 million at December 31, 2018.

Our lease obligations over the next five years are as follows (in thousands):

	Capital Leases	Operating Leases
2019	$ 540	$ 883
2020	537	395
2021	537	368
2022	537	366
2023	537	238
Thereafter	831	124
Total minimum payments	**3,519**	**$2,374**
Less amount representing interest	655	
Present value of net minimum lease payments	**$2,864**	

Expenses incurred related to operating leases were $1.0 million for 2018 and $0.8 million for 2017, respectively, excluding payments for wind generated purchased power agreements. The accumulated amount of amortization for our capital leases was $2.8 million and $2.5 million at December 31, 2018 and 2017, respectively.

Environmental Matters

We are subject to various federal, state, and local laws and regulations with respect to air and water quality and with respect to hazardous and toxic materials and hazardous and other wastes, including their identification, transportation, disposal, record-keeping and reporting, as well as remediation of contaminated sites and other environmental matters. We believe that our operations are in material compliance with present environmental laws and regulations. While we are not in a position to accurately estimate compliance costs for any new requirements, we expect these costs to be material, although recoverable in rates.

Compliance Plan

In order to comply with current and forthcoming environmental regulations, we implemented our compliance plan and strategy (2013 Compliance Plan), which largely follows our Integrated Resource Plan (IRP) filed with the MPSC in mid-2013. On April 1, 2016, we filed our updated IRP, reflecting the completion of our 2013 Compliance Plan. The Mercury Air Toxic Standards (MATS) and the Clean Air Interstate Rule (CAIR), replaced by the Cross State Air Pollution Rule (CSAPR), were the drivers behind our 2013 Compliance Plan and its implementation and completion schedule. Compliance costs we have incurred associated with the MATS, CAIR and CSAPR regulations are being recovered in our rates and we anticipate any future costs to continue to be recoverable in our rates.

The following list summarizes the most significant environmental regulations affecting our operations:

Regulations
Air Emissions - NOx and SO2
ACID RAIN
CAIR (Clean Air Interstate Rule)
CSAPR (Cross State Air Pollution Rule)
MATS (Mercury Air Toxic Standards)
NAAQS (National Ambient Air Quality Standards)
Greenhouse Gases (GHGs) – CO_2
Surface Impoundments
Coal Ash Impoundments:
Water Discharges

MATS: As noted above, the completion of our Compliance Plan puts us in compliance with MATS. At the end of 2018, the Environmental Protection Agency (EPA) proposed a major change in the way the federal government calculates the costs and benefits associated with the reduction of air pollutants. The EPA is not reversing the MATS standards (with which we have already complied), the agency plans to alter the underlying calculations to set a precedent for future public health rules.

Greenhouse Gases: On October 10, 2017, the EPA proposed to repeal the Clean Power Plan (CPP) and accepted comments through January 16, 2018. In addition, the EPA held public hearings on the proposed repeal on November 28th and 29th, 2017. In December 2017, the EPA issued an advance notice of proposed rulemaking (ANPRM) in which the agency proposed emission guidelines to limit GHG emissions from existing electric generating units (EGUs) and solicited information on the proper respective roles of the state and federal governments in that process, as well as information on systems of emission reduction that are applicable at or to an existing EGU, information on compliance measures, and information on state planning requirements under the Clean Air Act. This ANPRM did not propose any regulatory requirements. As a result of this ANPRM, on August 21, 2018, the EPA proposed the Affordable Clean Energy (ACE) rule which would establish emission guidelines for states to develop plans to address GHG emissions from existing coal-fired power plants. The ACE rule replaces the 2015 CPP, which the EPA has proposed to repeal because it exceeded the EPA's authority. The CPP was stayed by the U.S. Supreme Court and has never gone into effect.

The ACE rule has several components: a determination of the best system of emission reduction for GHG emissions from coal-fired power plants, a list of “candidate technologies” states can use when developing their plans, a new preliminary applicability test for determining whether a physical or operational change made to a power plant may be a “major modification” triggering New Source Review, and new implementing regulations for emission guidelines under Clean Air Act section 111(d).

Until the litigation and rulemaking regarding the CPP and ACE is resolved, it is difficult to determine the impact but could mean the addition of emission reduction technologies, reduced generation, alternate generation or demand reduction technologies.

Surface Impoundments: The EPA’s final revision of the Clean Water Act (CWA) Steam Electric Effluent Limitation Guidelines (ELGs) for coal-fired power plants set technology-based ELGs based on the nature of the pollutants being discharged and the facilities involved. These ELG guidelines are currently incorporated into the Asbury Plant waste discharge permit. The EPA rule defines bottom as transport water, fly ash transport water, and scrubber wastes as wastewaters which cannot be discharged after December 21, 2023.

The EPA’s final rule to regulate the disposal of coal combustion residuals (CCRs) as a non-hazardous solid waste under subtitle D of the Resource Conservation and Recovery Act (RCRA) impacts our Asbury plant. Empire has published a Closure Plan for the Asbury Plant CCR Impoundment. The plan schedule assumes Closure initiation in November 2020 with completion of the closure by October 2025. If we are unable to implement the Closure Plan for the Asbury Plant CCR Impoundment at this time, compliance will result in the need to construct at least one cell of a new landfill and complete the conversion of the existing bottom ash handling from a wet to a dry system to comply with both the CCR and ELG rules. Final closure of the existing ash impoundment, for which an asset retirement obligation of $15.5 million has been recorded, is anticipated after the new landfill is operational. In lieu of the expected impoundment closure, the new cell construction and the conversion of the existing ash handling system are expected to cost up to $3 million and $17 million, respectively. Separately, an asset retirement obligation of $4.4 million has been recorded for our interest in the coal ash impoundment at the Iatan Generating Station. We expect compliance costs to be recoverable in our rates.

On December 28, 2016, the Missouri Department of Natural Resources (MDNR) approved our permit application to construct a utility waste landfill on a 217-acre site adjacent to the Asbury plant.

Water Discharges: We operate under the Kansas and Missouri Water Pollution Plans pursuant to the Federal Clean Water Act (CWA). Our plants are in material compliance with applicable regulations and have received all necessary discharge permits. On September 17, 2018 KDHE issued a Certificate of Determination stating the Riverton Generating Station cooling water intake structure (CWIS) is in compliance with the EPA final rule under the CWA Section 316(b) for existing CWIS, which became effective on October 14, 2014, to meet new regulatory requirements for aquatic life protections. An industry coalition has filed an appeal of the rule and additional court challenges are expected. Impacts at Iatan 1 could range from flow velocity reductions, traveling screen modifications or the installation of a closed cycle cooling tower retrofit. Iatan Unit 2 and Plum Point Unit 1 are covered by the regulation, but were constructed with cooling towers, the proposed Best Technology Available. We expect them to be unaffected or minimally affected by the final rule.

Renewable Energy

The Missouri Clean Energy Initiative (Proposition C) requires Empire and other investor-owned utilities in Missouri to generate or purchase electricity from renewable energy sources, such as solar, wind, biomass and hydro power, or purchase Renewable Energy Credits (RECs), in amounts equal to at least 5% of retail sales in 2014-2017, at least 10% in 2018-2020 and at least 15% by 2021. We are currently in compliance with this regulatory requirement as a result of generation from our Ozark Beach Hydroelectric Project and purchased power agreements previously mentioned with Cloud County Windfarm, LLC and Elk River Windfarm, LLC. Proposition C also requires that 2% of the energy from renewable energy sources must be solar. On May 6, 2015, the MPSC approved tariffs we filed on May 5, 2015 to establish solar rebate payment procedures and revise our net metering tariffs to accommodate the payment of solar rebates. We expect solar rebates to be sufficient to allow compliance with the current 2% requirement. As of December 31, 2018, we had processed 1,860 solar rebate applications resulting in solar rebate-related costs totaling approximately $16.2 million under the new tariff. We have recorded the $16.2 million as a regulatory asset (See Note 3). The law provides a number of methods that may be utilized to recover the associated expenses. We expect any costs to be recoverable in rates.

12. RISK MANAGEMENT AND DERIVATIVE FINANCIAL INSTRUMENTS

We engage in hedging activities in an effort to minimize our risk from the volatility of natural gas prices. We enter into both physical and financial contracts with counterparties relating to our future natural gas requirements that lock in prices (with respect to a range of predetermined percentages of our expected future natural gas needs) in an attempt to lessen the volatility in our fuel expenditures and gain cost predictability.

We recognize that if risk is not timely and adequately balanced or if counterparties fail to perform contractual obligations, actual results could differ materially from intended results.

All financial derivative instruments are recognized at fair value on the consolidated balance sheets (See Note 1). The unrealized losses or gains from derivatives used to hedge our fuel and purchased power costs in our electric segment are recorded in regulatory assets or liabilities. All gains and losses from derivatives related to the gas segment are also recorded in regulatory assets or liabilities. This is in accordance with the ASC guidance on regulated operations, given that those gains or losses are probable of refund or recovery, respectively, through our fuel adjustment mechanisms.

Risks and uncertainties affecting the determination of fair value include: market conditions in the energy industry, especially the effects of price volatility, regulatory and global political environments and requirements, fair value estimations on longer term contracts, the effectiveness of the derivative instruments in hedging the change in fair value of the hedged item, estimating underlying fuel demand and counterparty ability to perform. If we estimate that we have overhedged forecasted demand, the gain or loss on the overhedged portion will be recognized immediately as fuel and purchased power expense in our consolidated statement of income and subject to our fuel adjustment mechanism.

As of December 31, 2018 and 2017, we have recorded the following assets and liabilities representing the fair value of derivative financial instruments held as of December 31, (in thousands):

ASSET DERIVATIVES		2018	2017
Non-Designated Hedging Instruments Due to Regulatory Accounting	**Balance Sheet Classification**	**Fair Value**	**Fair Value**
Natural gas contracts, gas segment	Current assets	$ 30	$ 20
	Noncurrent assets and deferred charges-Other	-	-
Natural gas contracts, electric segment	Current assets	14	-
	Noncurrent assets and deferred charges-Other	-	53
Transmission congestion rights, electric segment	Current assets	-	6,227
Total derivative assets		**$ 44**	**$ 6,300**

LIABILITY DERIVATIVES		2018	2017
Non-Designated as Hedging Instruments Due to Regulatory Accounting	**Balance Sheet Classification**	**Fair Value**	**Fair Value**
Natural gas contracts, gas segment	Current liabilities	$ 89	$ 89
	Non-current liabilities and deferred credits	-	71
Natural gas contracts, electric segment	Current liabilities	350	1,397
	Noncurrent liabilities and deferred credits	522	638
Transmission congestion rights, electric segment	Current liabilities	-	-
Total derivative liabilities		**$ 961**	**$ 2,195**

Electric Segment

At December 31, 2018, approximately $0.3 million of unrealized losses are applicable to financial instruments which will settle within the next twelve months.

The following tables set forth “mark-to-market” pre-tax gains/(losses) from non-designated derivative instruments for the electric segment for each of the years ended December 31 (in thousands):

Non-Designated Hedging Instruments – Due to Regulatory Accounting Electric Segment	Balance Sheet Classification of Gain/(Loss) on Derivative	Amount of Gain/(Loss) Recognized on Balance Sheet	
		2018	2017
Commodity contracts	Regulatory (assets)/liabilities	$ 1,259	$ (5,892)
Transmission congestion rights	Regulatory (assets)/liabilities	-	20,909
Total – Electric Segment		**$ 1,259**	**$ 15,017**

Non-Designated Hedging Instruments – Due to Regulatory Accounting Electric Segment	Statement of Operations Classification of Gain/(Loss) on Derivative	Amount of Gain/(Loss) Recognized in Income on Derivative			
			2018		2017
Commodity contracts	Fuel and purchased power expense	$	82	$	(1,503)
Transmission congestion rights	Fuel and purchased power expense		-		22,285
Total – Electric Segment		**$**	**82**	**$**	**20,782**

We also enter into fixed-price forward physical contracts for the purchase of natural gas, coal and purchased power. These contracts are not subject to fair value accounting because they qualify for the normal purchase normal sale exemption. We have a process in place to determine if any future executed contracts that otherwise qualify for the normal purchase normal sale exception contain a price adjustment feature and will account for these contracts accordingly.

As of December 31, 2018, the following volumes and percentage of our anticipated volume of natural gas usage for our electric operations for 2019 and the next four years are shown below at the following average prices per Dekatherm (Dth). We utilize the following procurement guidelines for our electric segment, allowing the flexibility to hedge up to 100% of the current year's and 80% of any future year's expected requirements while being cognizant of volume risk. The 80% guideline is an annual target and volumes up to 100% can be hedged in any given month. For years beyond year four, additional factors of long-term uncertainty (including with respect to required volumes and counterparty credit) are also considered. (Dth in thousands).

		Dth Hedged			Procurement
Year	% Hedged	Physical	Financial	Average Price	Guidelines
2019	50%	5,900	3,060	$ 2.612	Up to 100%
2020	19%	1,840	1,500	$ 2.789	60%
2021	13%	-	2,000	$ 2.900	40%
2022	0%	-	-	$ -	20%
2023	0%	-	-	$ -	10%

Gas Segment

We attempt to mitigate our natural gas price risk for our gas segment by a combination of (1) injecting natural gas into storage during the off-heating season months, (2) purchasing physical forward contracts and (3) purchasing financial derivative contracts. We target to have 95% of our storage capacity full by November 1 for the upcoming winter heating season. As the winter progresses, gas is withdrawn from storage to serve our customers. As of December 31, 2018, we had 1.2 million Dths in storage on the three pipelines that serve our customers. This represents 62% of our storage capacity.

The following table sets forth our long-term hedge strategy of mitigating price volatility for our customers by hedging a minimum of expected gas usage for the current winter season and the next two winter seasons by the beginning of the ACA year at September 1 and illustrates our hedged position as of December 31, 2018 (Dth in thousands).

Season	Minimum % Hedged	Dth Hedged Financial	Dth Hedged Physical	Dth in Storage	Actual % Hedged
Current	50%	300	-	1,191	80%
Second	Up to 50%	560	-	-	15%
Third	Up to 20%	-	-	-	-

A PGA clause is included in our rates for our gas segment operations, therefore, we mark to market any unrealized gains or losses and any realized gains or losses relating to financial derivative contracts to a regulatory asset or regulatory liability account on our consolidated balance sheets.

The following table sets forth "mark-to-market" pre-tax gains/(losses) from derivatives not designated as hedging instruments for the gas segment for the years ended December 31 (in thousands):

Non-Designated Hedging Instruments Due to Regulatory Accounting – Gas Segment	Balance Sheet Classification of Loss on Derivative	Amount of Gain/(Loss) Recognized on Balance Sheet	
		2018	2017
Commodity contracts	Regulatory (assets)/liabilities	$ 192	$ (427)
Total – Gas Segment		**$ 192**	**$ (427)**

Contingent Features

Certain of our derivative instruments contain provisions that are triggered if we fail to maintain an investment grade credit rating with any relevant credit rating agency. If our debt were to fall below investment grade, the counterparties to the derivative instruments could request increased collateralization on derivative instruments in net liability positions. We had no derivative instruments with the credit-risk-related contingent features in a net liability position on December 31, 2018 and have posted no collateral with counterparties in the normal course of business. Amounts reported as margin deposit assets represent our funds held on deposit for our contracts held with our NYMEX broker and other financial contracts with other counterparties that resulted from us exceeding agreed-upon credit limits established by the counterparties. The following table depicts our margin deposit assets at the dates shown. There were no margin deposit liabilities at these dates.

	December 31, 2018	December 31, 2017
(in millions)		
Margin deposit assets	$ 2.0	$ 4.6

Offsetting of derivative assets and liabilities

We believe that entering into master trading and netting agreements mitigates the level of financial loss that could result from a default under derivatives agreements by allowing net settlement of derivative assets and liabilities. We generally enter into the following master trading and netting agreements: (1) the International Swaps and Derivatives Association Agreement, a standardized financial natural gas and electric contract; and (2) the North American Energy Standards Board Inc. Agreement, a standardized contract for the purchase and sale of natural gas. These master trading and netting agreements allow the counterparties to net settle sale and purchase transactions. Collateral requirements are calculated at the master trading and netting agreement level by the counterparty.

As shown above, our asset and liability commodity contract derivatives are reported at gross on the consolidated balance sheets. ASC guidance permits companies to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a liability) against fair value amounts recognized for derivative instruments that are executed with the same counterparty under the same master netting arrangement. For the years ended December 31, 2018 and December 31, 2017, we did not hold any collateral posted by our counterparties. The only collateral we have posted is our margin deposit assets described above. We have elected not to offset our margin deposit assets against any of our eligible commodity contracts.

13. FAIR VALUE MEASUREMENTS

The accounting guidance on fair value measurements establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: (i) Level 1, defined as quoted prices in active markets for identical instruments; (ii) Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and (iii) Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. Our Level 2 fair value measurements consist of both quoted price inputs and inputs that are derived principally from or corroborated by observable market data.

The guidance also requires that the fair value measurement of assets and liabilities reflect the nonperformance risk of counterparties and the reporting entity, as applicable. Therefore, using credit default spreads, we factored the impact of our own credit standing and the credit standing of our counterparties, as well as any potential credit enhancements (e.g., collateral) into the consideration of nonperformance risk for both derivative assets and liabilities. The results of this analysis were not material to the consolidated financial statements.

Our commodity contracts are valued using the market value approach on a recurring basis. The following fair value hierarchy table presents information about our commodity contracts measured at fair value as of December 31:

($ in 000s)		Fair Value Measurements at Reporting Date Using		
Description	**Assets/(Liabilities) at Fair Value**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
		December 31, 2018		
Derivative assets	$ 44	$ 44	$ -	$ -
Derivative liabilities	$ (961)	$ (961)	$ -	$ -
		December 31, 2017		
Derivative assets	$ 6,300	$ 73	$ 6,227	$ -
Derivative liabilities	$ (2,195)	$ (2,195)	$ -	$ -

*The only recurring measurements are derivative related.

Other fair value considerations

Our cash and cash equivalents approximate fair value because of the short-term nature of these instruments, and are classified as Level 1 in the fair value hierarchy. The carrying amount of our short-term debt, which is composed of Empire issued commercial paper or revolving credit borrowings, also approximates fair value because of their short-term nature. These instruments are classified as Level 2 in the fair value hierarchy as they are valued based on market rates for similar market transactions.

The carrying amount of our total long-term debt exclusive of capital leases at December 31, 2018 and 2017 was $738 million and $827 million, compared to a fair market value of approximately $770 million and $926 million, respectively. In addition, there is an outstanding long term payable to Liberty Utilities Co. of $90 million as of December 31, 2018. These estimates were based on a bond pricing model, utilizing inputs classified as Level 2 in the fair value hierarchy, which include the quoted market prices for the same or similar issues or on the current rates offered to us for debt of the same remaining maturities. The estimated fair market value may not represent the actual value that could have been realized as of December 31, 2018 or that will be realizable in the future.

14. REGULATED OPERATING EXPENSE

The following table sets forth the major components comprising “regulated operating expenses” under “operating revenue deductions” on our consolidated statements of income for the years ended (in thousands):

	December 31, 2018	December 31, 2017
Power operation expense (other than fuel)	$ 18,450	$ 17,916
Electric transmission and distribution expense	29,316	29,478
Natural gas transmission and distribution expense	2,788	2,321
Customer accounts and assistance expense	12,962	12,069
Employee pension expense (1)	5,163	12,300
Employee healthcare plan (1)	10,056	11,342
General office supplies and expense	5,469	10,510
Administrative and general expense	31,140	23,774
Bad debt expense	3,071	1,880
Miscellaneous expense	598	362
TOTAL	$ 119,013	$ 121,952

(1) Does not include capitalized portion of costs, but reflects the GAAP expensed cost plus or minus costs deferred to and amortized from a regulatory asset and/or a regulatory liability for Missouri, Kansas and Oklahoma jurisdictions.

15. MERGERS AND ACQUISITIONS

Merger with Liberty Utilities (Central) Co. and Liberty Sub Corp.

On February 9, 2016, Empire entered into an Agreement and Plan of Merger (the Merger Agreement) with Liberty Utilities Central, a Delaware corporation (Liberty), and Merger Sub, a Kansas corporation, providing for the merger of Merger Sub with and into Empire, with Empire surviving the merger as a whollyowned subsidiary of Liberty Central (The Merger). The Merger closed on January 1, 2017. Pursuant to the Merger Agreement, at the effective time of the Merger, each issued and outstanding share of Empire common stock (other than any shares owned by Empire or Algonquin Power & Utilities Corp. (APUC) or any of their respective subsidiaries or any shares for which appraisal rights have been perfected) was cancelled and converted automatically into the right to receive $34.00 in cash, without interest.

On June 16, 2016, Empire’s stockholders voted to approve the merger. All required regulatory approvals and consents were also received in 2016. In connection with each of the regulatory approvals received, Liberty Central agreed to certain commitments regarding ongoing service to Empire customers, employment of Empire personnel, cost-sharing mechanisms, and compliance with existing regulatory stipulations in the normal course of business.

Pursuant to the Merger Agreement, and subsequent to the closing of the Merger, 37,162 shares of time-vested restricted stock grants that were outstanding immediately prior to the closing of the Merger were cancelled and converted into the right to receive a lump-sum cash payment equal to $34.00 per share. Payment of the lump-sum cash awards were made in January 2017 and totaled approximately $1.3 million.

Additionally, 42,600 shares of performance-based restricted stock granted under the 2006 SIP and the 2015 SIP that were outstanding immediately prior to the closing of the Merger were cancelled and converted into the right to receive a lump-sum cash payment. In accordance with the Merger Agreement, the performance-based restricted stock was paid equal to $34.00 per share multiplied by the total number of shares of common stock that would have been earned for performance at “target” over the performance period under the grant. Payment of these lump-sum cash awards were made in January 2017 and totaled approximately $3.1 million.

In connection with entering into the Merger Agreement, Empire incurred approximately $8.9 million and $9.1 million of transaction costs during 2017 and 2016, respectively. We did not incur significant transaction costs during 2018 as a result of the Merger, and do not expect regulatory recovery of these costs in any jurisdiction that we serve.

The Board of Directors adopted a Change In Control Severance Pay Plan (“Severance Plan”) in 1991, amended most recently in 2008, that covers the Company’s executive officers as well as other key employees who are not executive officers. The Severance Plan provides severance payments and other benefits upon involuntary or voluntary termination of employment after a change in control. The completion of the Merger on January 1, 2017 triggered certain aspects of the Severance Plan and certain officers elected voluntary termination in accordance with the Severance Plan. The Company has recorded approximately $33.2 million of Severance Plan related expenses in 2017 based on officer terminations. Payment of these Severance Plan expenses will occur over several years, in accordance with the schedules determined for each officer receiving the benefits.

We have evaluated subsequent events through March 29, 2019, the date the consolidated financial statements were available to be issued.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/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				[redacted]	
2					
3					
4					
5				[redacted]	
6					
7					
8					
9					
10				[redacted]	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	2,477,262,119	2,464,043,579
4	Property Under Capital Leases	5,213,047	5,213,047
5	Plant Purchased or Sold		
6	Completed Construction not Classified	402,923,448	402,081,799
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	2,885,398,614	2,871,338,425
9	Leased to Others		
10	Held for Future Use	872,756	872,756
11	Construction Work in Progress	45,789,463	45,600,880
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	2,932,060,833	2,917,812,061
14	Accum Prov for Depr, Amort, & Depl	979,338,394	973,444,969
15	Net Utility Plant (13 less 14)	1,952,722,439	1,944,367,092
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	956,557,037	950,663,612
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	22,781,357	22,781,357
22	Total In Service (18 thru 21)	979,338,394	973,444,969
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	979,338,394	973,444,969

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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

Gas (d)	Other (Specify) *Water* (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
	13,218,540				3
					4
					5
	841,649				6
					7
	14,060,189				8
					9
					10
	188,583				11
					12
	14,248,772				13
	5,893,425				14
	8,355,347				15
					16
					17
	5,893,425				18
					19
					20
					21
	5,893,425				22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
	5,893,425				33

Schedule Page: 200 Line No.: 8 Column: b

Reconciliation to Ferc Pg 110:

2,885,398,614	Ferc Pg 200, Line 8
872,756	Ferc Pg 200, Line 10
2,886,271,370	Ferc Pg 200, Lines 8 & 10
80,777	Non-Utility - Regulated
151,312	Non-Utility - Electric Car Charging Stations
2,886,503,459	Ferc Pg 110, Line 2

Schedule Page: 200 Line No.: 14 Column: b

Reconciliation to Ferc Pg 110:

979,349,137	Ferc Pg 110, Line 5
(10,743)	Non-Regulated Non-Utility
979,338,394	Ferc Pg 200, Line 14, 22 & 33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
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)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/13/2019	End of 2018/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	29,940	
3	(302) Franchises and Consents	1,079,798	
4	(303) Miscellaneous Intangible Plant	40,259,657	2,212,535
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	41,369,395	2,212,535
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	2,435,380	
9	(311) Structures and Improvements	82,531,040	495,246
10	(312) Boiler Plant Equipment	535,460,400	6,411,730
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	117,802,563	1,673,144
13	(315) Accessory Electric Equipment	37,987,628	423,860
14	(316) Misc. Power Plant Equipment	7,785,674	97,367
15	(317) Asset Retirement Costs for Steam Production	17,721,371	2,195,371
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	801,724,056	11,296,718
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	226,488	
28	(331) Structures and Improvements	810,803	31,358
29	(332) Reservoirs, Dams, and Waterways	3,417,693	12,164
30	(333) Water Wheels, Turbines, and Generators	3,161,774	1,166,758
31	(334) Accessory Electric Equipment	1,449,464	54,297
32	(335) Misc. Power PLant Equipment	597,207	73,082
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	9,663,429	1,337,659
36	D. Other Production Plant		
37	(340) Land and Land Rights	1,267,014	
38	(341) Structures and Improvements	41,289,140	600,674
39	(342) Fuel Holders, Products, and Accessories	7,857,146	-38,946
40	(343) Prime Movers	366,185,124	5,877,702
41	(344) Generators	64,542,447	2,704,941
42	(345) Accessory Electric Equipment	45,026,684	1,076,708
43	(346) Misc. Power Plant Equipment	10,334,144	482,217
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	536,501,699	10,703,296
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,347,889,184	23,337,673

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The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	11,923,369	1,074
49	(352) Structures and Improvements	2,906,760	794,101
50	(353) Station Equipment	162,246,746	14,480,399
51	(354) Towers and Fixtures	1,817,801	326,358
52	(355) Poles and Fixtures	90,738,372	5,507,709
53	(356) Overhead Conductors and Devices	90,058,893	7,310,081
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	359,691,941	28,419,722
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,128,842	497,244
61	(361) Structures and Improvements	26,143,006	549,971
62	(362) Station Equipment	124,780,101	11,301,232
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	208,028,481	8,350,520
65	(365) Overhead Conductors and Devices	210,763,682	5,283,000
66	(366) Underground Conduit	43,013,009	4,850,624
67	(367) Underground Conductors and Devices	65,807,158	2,740,141
68	(368) Line Transformers	120,421,884	6,437,600
69	(369) Services	84,450,221	4,558,338
70	(370) Meters	24,570,957	126,141
71	(371) Installations on Customer Premises	17,104,340	778,722
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	19,717,510	755,343
74	(374) Asset Retirement Costs for Distribution Plant	183,153	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	949,112,344	46,228,876
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
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)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	1,057,907	
87	(390) Structures and Improvements	11,697,714	349,685
88	(391) Office Furniture and Equipment	20,862,734	978,716
89	(392) Transportation Equipment	14,341,659	882,342
90	(393) Stores Equipment	855,334	22,191
91	(394) Tools, Shop and Garage Equipment	6,974,820	197,765
92	(395) Laboratory Equipment	1,985,646	28,095
93	(396) Power Operated Equipment	18,252,136	-3,904
94	(397) Communication Equipment	11,876,741	84,169
95	(398) Miscellaneous Equipment	277,438	8,810
96	SUBTOTAL (Enter Total of lines 86 thru 95)	88,182,129	2,547,869
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)	88,182,129	2,547,869
100	TOTAL (Accounts 101 and 106)	2,786,244,993	102,746,675
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)	2,786,244,993	102,746,675

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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
			29,940		2
			1,079,798		3
			42,472,192		4
			43,581,930		5
					6
					7
			2,435,380		8
111,443			82,914,843		9
2,824,795			539,047,335		10
					11
114,602			119,361,105		12
334,814			38,076,674		13
22,501			7,860,540		14
4,512,520			15,404,222		15
7,920,675			805,100,099		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			226,488		27
130			842,031		28
11,180			3,418,677		29
30,303			4,298,229		30
1,663			1,502,098		31
2,550			667,739		32
					33
					34
45,826			10,955,262		35
					36
			1,267,014		37
58,331			41,831,483		38
			7,818,200		39
1,632,002			370,430,824		40
17,296			67,230,092		41
148,832			45,954,560		42
19,246			10,797,115		43
					44
1,875,707			545,329,288		45
9,842,208			1,361,384,649		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
			11,924,443		48
23,001			3,677,860		49
1,502,956		-17,263	175,206,926		50
2,854			2,141,305		51
148,766			96,097,315		52
121,913			97,247,061		53
					54
					55
					56
					57
1,799,490		-17,263	386,294,910		58
					59
			4,626,086		60
75,845			26,617,132		61
2,100,354		17,264	133,998,243		62
					63
358,835		-1,425	216,018,741		64
364,562		3,277	215,685,397		65
107,023		-1,852	47,754,758		66
90,362			68,456,937		67
677,261			126,182,223		68
20,925			88,987,634		69
101,449		-100,858	24,494,791		70
183,094		100,858	17,800,826		71
					72
287,482			20,185,371		73
			183,153		74
4,367,192		17,264	990,991,292		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			1,057,907		86
1,449			12,045,950		87
651,219			21,190,231		88
428,023		-14,805	14,781,173		89
			877,525		90
16,131			7,156,454		91
			2,013,741		92
502,419			17,745,813		93
21,870			11,939,040		94
8,438			277,810		95
1,629,549		-14,805	89,085,644		96
					97
					98
1,629,549		-14,805	89,085,644		99
17,638,439		-14,804	2,871,338,425		100
					101
					102
					103
17,638,439		-14,804	2,871,338,425		104

Schedule Page: 204 Line No.: 46 Column: g

This footnote applies to Ferc Pg 205, Line 46, Column g. The inputs to Worksheet C, (Line 1) of the Company's GFR 2019 Annual Update will be adjusted to remove any Asset Retirement Obligations from Production Plant in Service (as identified in Ferc Form 1 Line 15) that have not been approved by Ferc for inclusion in Empire's formula rates.

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

This footnote applies to Ferc Pg 207, Line 46, Column g. The inputs to Worksheet C (Line 5) of the Company's GFR 2019 Annual Update will be adjusted to remove any Asset Retirement Obligations from Total Plant in Service (as identified in Ferc Form 1, Pages 205 & 207, Lines 15 & 74 that have not been approved by Ferc for inclusion in Empire's formula rates.

The input to the Inputs Page (Line 32) of the Company's TFR 2019 Annual Update will be adjusted to remove any Asset Retirement Obligations from Total Plant in Service (as Ferc for inclusion in Empire's formula rates.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/13/2019	End of 2018/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					
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46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/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	Tract of land in Jasper County, MO adjacent to			
3	Energy Center purchased in 1992 from Glover &			
4	Haggard ME9901C	11/30/92	Unknown	250,000
5				
6	Survey plat & legal desc of tract in Jasper County,			
7	MO adjacent to Energy Center	5/31/93	Unknown	6,413
8				
9	Land for Bolivar MO Service Center - MG7593C	2008	Unknown	288,209
10				
11	Branson Sub 454 Site 207MD10007C	2009	Q4-2019	83,772
12				
13	Gentry West Sub 458 Site 216AD3951C	2009	Unknown	114,358
14				
15	Asbury Common 23.7 Acres SE Qtr - E 1/2 SW Qtr			
16	S17 - T30 - R33 Jasper County MO	2016	Unknown	130,004
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
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39				
40				
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46				
47	Total			872,756

Schedule Page: 214 Line No.: 2 Column: c

The Company currently does not have an estimated in-service date for any of the property listed below except for the Branson Sub 454 Site (Line 11).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	ARKANSAS:	
2	Distribution Plant - Electric - 9 Minor Projects	4,379
3	General Plant - Electric - 1 Minor Project	-4,319
4	Steam Generation Plant - 1 Minor Project	-77,740
5	Transmission Plant - Electric - 7 Minor Projects	33,545
6		
7	KANSAS:	
8	Distribution Plant - Electric - 29 Minor Projects	1,041,719
9	General Plant - Electric - 1 Minor Project	16,346
10	Other Generation Plant - 1 Minor Project	58,611
11	Other Generation Plant - Neosho Ridge Wind Development	3,050,139
12	Transmission Plant - Electric - 12 Minor Projects	821,539
13		
14	MISSOURI:	
15	Distribution Plant - Electric - 259 Minor Projects	6,595,319
16	Distribution Plant - Electric - Construction Design Automation	1,328,517
17	Distribution Plant - Electric - Add 2nd 22.4 MVA Xfmr at 434	1,360,315
18	Distribution Plant - Electric - Build 69/12 kV Willard E Sub 47	1,362,310
19	Distribution Plant - Electric - Build 161/12 kV Hollister S Sub	3,530,851
20	General Plant - Electric - 12 Minor Projects	1,122,058
21	Hydro Generation Plant - 1 Minor Project	16,595
22	Hydro Generation Plant - Hydro-Dam FERC Relicensing	1,027,923
23	Intangible Plant - 2 Minor Projects	120,391
24	Other Generation Plant - 10 Minor Projects	707,571
25	Other Generation Plant - Regulatory Chrgs Related to Wind	2,868,179
26	Other Generation Plant - Site Study - Wind Project	6,535,772
27	Steam Generation Plant - 92 Minor Projects	2,550,894
28	Steam Generation Plant - Install Landfill Cell	1,509,926
29	Steam Generation Plant - Inst Landfill Phase 3 Expansion	2,307,791
30	Transmission Plant - Electric - 113 Minor Projects	5,730,585
31	Transmission Plant - Electric - Install 3-161 kV Bkrs at 395	1,227,430
32		
33	OKLAHOMA:	
34	Distribution Plant - Electric - 15 Minor Projects	714,164
35	Transmission Plant - Electric - 4 Minor Projects	50,517
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	45,611,327

Schedule Page: 216 Line No.: 37 Column: a

45,611,327	Ferc Pg 216 Line 43
(10,447)	Stockton Charging Station
45,600,880	Ferc Pg 200 Line 11 Column C

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	889,155,687	889,155,687		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	77,793,026	77,793,026		
4	(403.1) Depreciation Expense for Asset Retirement Costs	4,301,919	4,301,919		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	2,220,427	2,220,427		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	3,212,660	3,212,660		
9	Jurisdictional Adjustments	-225,537	-225,537		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	87,302,495	87,302,495		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	13,125,921	13,125,921		
13	Cost of Removal	8,526,694	8,526,694		
14	Salvage (Credit)	385,238	385,238		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	21,267,377	21,267,377		
16	Other Debit or Cr. Items (Describe, details in footnote):	-14,673	-14,673		
17					
18	Book Cost or Asset Retirement Costs Retired	-4,512,520	-4,512,520		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	950,663,612	950,663,612		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	216,539,472	216,539,472		
21	Nuclear Production				
22	Hydraulic Production-Conventional	3,086,132	3,086,132		
23	Hydraulic Production-Pumped Storage				
24	Other Production	139,681,907	139,681,907		
25	Transmission	98,621,852	98,621,852		
26	Distribution	440,546,001	440,546,001		
27	Regional Transmission and Market Operation				
28	General	52,188,248	52,188,248		
29	TOTAL (Enter Total of lines 20 thru 28)	950,663,612	950,663,612		

Schedule Page: 219 Line No.: 8 Column: c

RWIP

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

Transfer

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

The inputs to Worksheet Q (Lines 6 & 9, Col c) and Worksheet C (Lines 8, 9 & 13) of the Company's GFR 2019 Annual Update will be adjusted per the revised Depreciation Reserve calculations shown below. The inputs to Worksheet Q (Lines 6 & 9) will also be further reduced by $37,312,953 to reflect the impact of the Missouri Regulatory Plan.

Schedule Page: 219 Line No.: 29 Column: b

The inputs to the Inputs Page (Lines 47, 48 & 49) of the Company's TFR 2019 Annual Update will be adjusted per the revised Depreciation Reserve calculations shown below. ATT-11 (Page 1, Line 6) will further reduce the Depreciation Reserves by $32,959,775 per the Missouri Regulatory Plan table shown in footnote 6 of ATT-11.

Recalculation of Accumulated Depreciation using FERC approved depreciation rates only, exclusive of accumulated depreciation associated with Asset Retirement Obligations not approved by FERC for inclusion in Empire's formula rates:

Line	Column A	Column B
20	Est Accum Depr Res, Steam Generation	161,590,856
22	Est Accum Depr Res, Hydro Generation	2,912,228
24	Est Accum Depr Res, Other Generation	145,809,497
25	Est Accum Depr Res, Transmission Plant	99,864,800
26	Est Accum Depr Res, Distribution Plant	395,269,802
28	Est Accum Depr Res, General Plant	52,687,370
29	Total Estimated Accum Depr Reserve	**858,134,553**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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	EDE Holdings - Securities			1,000
2	Advances - Subsidiary Investments			35,247,157
3	Advances - Other			-3,609,501
4	Subsidiary Earnings			33,895,861
5				
6				
7				
8				
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38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	65,534,517

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
		1,000		1
		35,247,157		2
		-3,609,501		3
3,611,817		37,507,678		4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
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				41
3,611,817		69,146,334		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/13/2019	End of 2018/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	24,111,839	21,690,759	
2	Fuel Stock Expenses Undistributed (Account 152)	3,603	63	
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)	31,220,248	35,446,397	
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	13,269,809	16,035,782	
8	Transmission Plant (Estimated)	2,883,317	3,173,764	
9	Distribution Plant (Estimated)	11,526,079	12,686,442	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	1,586,778	1,809,748	Water-Fiber-Gas
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	29,265,983	33,705,736	
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)	22,652	8,399	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	84,624,325	90,851,354	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year	43,781.00			
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	15,502.00		15,502.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Iatan	1,979.00			
10	Plum Point				
11	Westar	4.00			
12					
13					
14					
15	Total	1,983.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509	1,498.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23	Sale of CSAPR SO2 to:				
24	Next ERA Energy				
25					
26					
27					
28	Total				
29	Balance-End of Year	59,768.00		15,502.00	
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	167.00		167.00	
38	Deduct: Returned by EPA				
39	Cost of Sales	167.00			
40	Balance-End of Year			167.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)	-167.00	-10		
44	Net Sales Proceeds (Other)	167.00	10		
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2020		2021		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						43,781.00		1
								2
								3
15,502.00		15,502.00		62,008.00		124,016.00		4
								5
								6
								7
								8
						1,979.00		9
								10
						4.00		11
								12
								13
								14
						1,983.00		15
								16
								17
						1,498.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
15,502.00		15,502.00		62,008.00		168,282.00		29
								30
								31
								32
								33
								34
								35
								36
167.00		167.00		668.00		1,336.00		37
								38
				167.00		334.00		39
167.00		167.00		501.00		1,002.00		40
								41
								42
				-167.00	-3	-334.00	-13	43
				167.00	3	334.00	13	44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year	1,628.00			
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	2,181.00		2,181.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Transfer from Iatan	386.00			
10	Transfer from Westar	9.00			
11					
12					
13					
14					
15	Total	395.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509	1,619.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23	Transfer out to Westar	1.00			
24					
25					
26					
27					
28	Total	1.00			
29	Balance-End of Year	2,584.00		2,181.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2020		2021		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						1,628.00		1
								2
								3
2,181.00		2,181.00		8,724.00		17,448.00		4
								5
								6
								7
								8
						386.00		9
						9.00		10
								11
								12
								13
								14
						395.00		15
								16
								17
						1,619.00		18
								19
								20
								21
								22
						1.00		23
								24
								25
								26
								27
						1.00		28
2,181.00		2,181.00		8,724.00		17,851.00		29
								30
								31
								32
								33
								34
								35
								36
								37
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								43
								44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/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 Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/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 Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22						
23						
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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**				
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21	**Generation Studies**				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/13/2019	End of 2018/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Deferred Tax Asset - FAS 109	13,333,691	1,430,669	283	5,050,591	9,713,769
2	Asset Retirement Obligation	16,050,994	4,966,253	403		21,017,247
3	Deferred Tax Asset-Equity AFUDC	13,491,784	710,097		1,529,991	12,671,890
4	Loss Int Rate Deriv 5.8% Note 7/1/35 (30 Yr Amort)	804,612		428	46,198	758,414
5	Cust Prog Collaborative EO-2005-0263 (10 Yr Amort)	5,433,657	1,080,069	908	1,637,094	4,876,632
6	KS ECA Docket 05-EPDE-980-RTS	123,392	526,528			649,920
7	FAS 158 Pension - ER-2006-0315	(432,565)	20,865,034	228	77,913	20,354,556
8	FAS 158 OPEB - ER-2006-0315	(2,866,151)	12,811,134	228		9,944,983
9	Arkansas DSM - AR 07-076-TF	(52,022)	27,175	908	64,083	-88,930
10	KS 2007 Ice Storm Def Charge 08-EPDE-714-ACT	277,677		593	111,071	166,606
11	KS 2007 Ice Storm Carrying Cost 08-EPDE-714-ACT	54,025		593	21,610	32,415
12	EDG DSM Costs GR-2009-0434					
13	Reg Pension Costs Amort ER-2004-0570	1,953,441	302,580	254, 926	907,740	1,348,281
14	Def MO Fuel Cost Rec ER-2008-0093 (6 Mon Amort)	4,351,739	15,820,608	254, 501	20,172,347	
15	Iatan Deferred Carrying Costs EO-2005-0263	4,877,897		403, 421	154,680	4,723,217
16	MO Pension FAS 87 ER-2004-0570	(1,126,469)	3,656,931	182, 926	1,424,052	1,106,410
17	MOFAC Unrealized Deriv ER-2008-0093	2,133,110	1,075,090		2,408,243	799,957
18	ITC Tax Basis Reduction - Iatan	5,215,873			440,986	4,774,887
19	MO Plum Pt Def Chgs ER-2010-0130	148,116		403, 421	3,205	144,911
20	MO Iatan II Def Chgs ER-2010-0130	9,317,880		403, 421	199,811	9,118,069
21	KS Pension FAS 87 Expense	957,887	243,268			1,201,155
22	KS OPEB Tracker	379,134	39,879		2,349	416,664
23	MEEIA Energy Efficiency Costs MO-ER-2012-0345	136,212		908		136,212
24	May 2011 Tornado Storm Deferral MO-ER-2012-0345	443,109		593	84,402	358,707
25	MO 2011 Tornado Depr Deferral MO-ER-2012-0345	706,381		403	134,549	571,832
26	May 2011 Tornado Carrying Costs MO-ER-2012-0345	963,712		426	183,564	780,148
27	Peoplesoft Costs ER-2011-0004	148,690		921	31,303	117,387
28	OK Pension Under Recovered Amt	276,313	119,038			395,351
29	Def OK Fuel Cost PUD201100082		323,701	501		323,701
30	Bank Credit Fees ER-2012-0345 (45 Mo Amort)	156,998	53,472	107	210,470	
31	Vegetation Tracker ER-2012-0345	1,618,619			436,482	1,182,137
32	Reclass - Noncurrent	(12,386,307)	12,386,307	182	15,475,428	-15,475,428
33	Reclass - Current	12,386,307	15,475,428	182	12,386,307	15,475,428
34	Def MO Fuel Cost Current ER-2008-0093	8,038,282	13,514,710	254, 501	15,657,988	5,895,004
35	KS ECA-ACA	544,406	574,250			1,118,656
36	Riverton 12 LTM Tracker ER2014-0351	4,550,045	3,732,674	553		8,282,719
37	MO Solar Initiative	6,937,203	3,527,575		143,781	10,320,997
38	Iatan II O&M Tracker ER2014-0351	(111,851)		500, 510	(65,474)	-46,377
39	Iatan Common O&M Tracker ER2014-0351	432,254		500, 510	253,027	179,227
40	Plum Point O&M Tracker ER2014-0351	62,815		500, 510	36,769	26,046
41	OK OPEB Under Recovered Amt	2,240		926		2,240
42	Low Inc Rate Pilot ER-2016-002	3,149				3,149
43	Solar RB to Amrt ER-2016-0023	5,399,641		908	620,054	4,779,587
44	TOTAL	184,292,080	114,716,155		90,986,138	208,022,097

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Reg Asset EDE Pension Acquisition	77,283,539	1,453,685		9,478,517	69,258,707
2	Reg Asset EDE OPEB Acquisition	2,272,621			1,667,007	605,614
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44	TOTAL	184,292,080	114,716,155		90,986,138	208,022,097

Schedule Page: 232 Line No.: 17 Column: d

244, 254, 501, 547

Schedule Page: 232 Line No.: 31 Column: d

571,593,594

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/13/2019	End of 2018/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Five Year Maintenance Overhaul	119,856		513	119,856	
2	(12-2013 to 11-2018)					
3						
4	Other Deferred Debits	43,308	9,811		14,154	38,965
5						
6	Electric - Rate Case Expenses	691,075	418,149	692, 928	18,744	1,090,480
7	(Various Amortization Periods)					
8						
9	Iatan Arbitration Expenses	378,869		923	8,482	370,387
10	(9-2010 to 8-2062)					
11						
12	May 2009 Windstorm	3,025		593		3,025
13	(Various Amortization Periods)					
14						
15	Financing Exp - Secured Debt	35		181	35	
16	(Not Amortized)					
17						
18	Riverton Def Maint Contract	704,539			449,125	255,414
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47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	1,940,707				1,758,271

Schedule Page: 233   Line No.: 4   Column: d

501, 553, 921

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2			
3			
4			
5			
6			
7	Other (See footnote for details)	100,346,304	83,853,077
8	TOTAL Electric (Enter Total of lines 2 thru 7)	100,346,304	83,853,077
9	Gas		
10			
11			
12			
13			
14			
15	Other CIAC - Water	12,032	12,032
16	TOTAL Gas (Enter Total of lines 10 thru 15	12,032	12,032
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	100,358,336	83,865,109

Notes

Schedule Page: 234 Line No.: 7 Column: b

Other Detail:

	Beg Balance	End Balance
L.D. - Arkansas Jurisdictional	2,459	2,249
Realized Gain on Hedging Transactions	717,571	706,981
Misc - Other (See Below)*	(3,259,996)	(3,709,379)
Plant Disallowances	1,339,584	888,940
Deferred Compensation	123,700	(1,237,246)
Contributions in Aid of Construction	7,073,265	6,480,121
Deferred Tax Asset - FAS 109	61,218,284	56,776,438
Postretirement Benefits Other Than Pension Costs - Missouri	(419,711)	303,012
Postretirement Benefits - Pensions	(4,950,348)	(4,156,441)
Interest Capitalized	11,845,737	10,835,391
Future Pensions & OPEB - FAS 158	15,457,806	13,428,575
Deferred Revenues - Ozark Beach Loss	(1,121,777)	(1,026,250)
Adv Coal Credit ITC - Not Currently Applied	1,808,482	(2,776,272)
Deferred Tax Asset - NOL & ITC Carrybacks - Current	5,173,891	2,621,928
Regulatory Plan Amortization	5,337,357	4,715,030
Total	**100,346,304**	**83,853,077**

***Water Included:**

Balance 01/01/2018	12,032
2018 Amortization	
Balance 12/31/2018	12,032

Miscellanous - Other:

Acct 190124	(3,923,119)
Acct 190125	646,911
Acct 190350	(433,171)
Total	**(3,709,379)**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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	100,000,000	1.00	
2				
3				
4	TOTAL COMMON	100,000,000		
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8				
9	TOTAL PREFERRED			
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CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT AS REACQUIRED STOCK (Account 217)		HELD BY RESPONDENT IN SINKING AND OTHER FUNDS		Line No.
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
43,993,363	43,993,363					1
						2
						3
43,993,363	43,993,363					4
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OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 211:	
2	All Miscellaneous Paid in Capital as a Result of	
3	Refinancing and Merger Transactions in the Year 1944	
4	per Federal Power Commission Docket No. IT-5899	787,482
5		
6	Miscellaneous Paid in Capital for Stock Compensation Tax Windfalls	
7	Based upon FAS123	147,852
8		
9	Miscellaneous Paid in Capital for Employee Stock Purchase Plan	
10		
11	Less:	
12	Changes in 1948 for Disposition of a Portion of the Amount Classified	
13	in Account 116 - Other Electric Plant Adjustments as per Order of the	
14	Federal Power Commission, Dated February 8, 1949.	-68,399
15	SUBTOTAL	866,935
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40	TOTAL	866,935

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	Common	21,935,000
2		
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22	TOTAL	21,935,000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/13/2019	End of 2018/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	4.65% Series, Due 2020 181.5	100,000,000	1,181,239
2			214,000 D
3	5.20% Series, Due 2040 181.983	50,000,000	855,514
4			151,500 D
5			
6	5.875% Series, Due 2037 181.801	80,000,000	2,956,954
7			168,800 D
8			
9	6.375% Series, Due 2018 181.4	90,000,000	1,136,646
10			50,400 D
11			
12	6.70% Senior Notes, Due 2033 181.102	62,000,000	-4,386,647
13			241,180 D
14			
15	5.80% Senior Notes, Due 2035 181.103	40,000,000	1,934,750
16			220,000 D
17			
18	3.58% Series, Due 2027 181.984	88,000,000	1,182,530
19			
20	3.73% Series, Due 2033 181.985	30,000,000	368,930
21			
22	4.32% Series, Due 2043 181.986	120,000,000	1,428,055
23			
24	4.27% Series, Due 2044 181.987	60,000,000	661,341
25			
26	3.59% Series, Due 2030 181.803	60,000,000	487,949
27			
28	4.53% Series, Due 2033 181.104	90,000,000	452,967
29	Note Payable to Liberty Utilities Co		
30			
31			
32			
33	TOTAL	870,000,000	9,306,108

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
5/28/2010	6/01/2020	5/01/2010	4/30/2020	100,000,000	4,650,000	1
						2
8/25/2010	9/01/2040	8/01/2010	7/31/2040	50,000,000	2,600,000	3
						4
						5
3/26/2007	4/01/2037	3/01/2007	2/28/2037	80,000,000	4,700,000	6
						7
						8
5/16/2008	6/01/2018	5/01/2008	4/30/2018		2,390,625	9
						10
						11
11/03/2003	11/15/2033	11/01/2003	10/31/2033	62,000,000	4,154,000	12
						13
						14
6/27/2005	07/01/2035	6/01/2005	7/01/2035	40,000,000	2,320,000	15
						16
						17
4/02/2012	4/02/2027	4/01/2012	3/31/2027	88,000,000	3,150,400	18
						19
5/30/2013	5/30/2033	5/30/2013	5/30/2033	30,000,000	1,119,000	20
						21
5/30/2013	5/30/2043	5/30/2013	5/30/2043	120,000,000	5,184,000	22
						23
12/01/2014	12/01/2044	12/01/2014	12/01/2044	60,000,000	2,562,000	24
						25
8/20/2015	8/20/2030	8/20/2015	8/20/2030	60,000,000	2,154,000	26
						27
6/01/2018	6/01/2033	6/30/2018	5/31/2033	90,000,000	2,378,250	28
						29
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				780,000,000	37,362,275	33

Schedule Page: 256 Line No.: 30 Column: b

The 6.82% Series First Mortgage Bonds were issued June 1, 2006 under the First Supplemental Indenture of the Empire District Gas Company and are not included in the financial statement of the electric utility.

The Empire District Gas Company Mortgage Bonds:

Outstanding amount, beginning and end of year	$55,000,000
Associated Interest for the year	$ 3,751,000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	120,479,038
2		
3		
4	Taxable Income Not Reported on Books	
5	See Footnote	3,410,864
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	See Footnote on Line 5	27,700,949
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	See Footnote on Line 5	5,649,076
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See Footnote on LIne 5	51,360,431
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	94,581,344
28	Show Computation of Tax:	
29		
30	Less: State Benefit Included (Estimated)	-3,868,377
31		
32	Federal Tax Net Income/(Loss)	90,712,967
33		
34	Federal Income Tax	18,469,160
35		
36	2016 Return to Accrual & Amended Returns	10,684,285
37		
38	Current Federal Tax (Before Adjustments)	29,153,445
39		
40		
41		
42		
43		
44	Federal Current Tax Recorded for Year	17,927,353

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) __ An Original (2) X A Resubmission	05/13/2019	2018/Q4

FOOTNOTE DATA

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

Reconciliation of Reported Net Income with Taxable Income	
for Federal Income Taxes - Supplement (Ferc Pg 117)	120,479,038
Taxable Income not Reported on Books	
Contributions in Aid of Construction	3,410,864
Deductions Recorded on Books not Deducted for Return:	
Federal Income Tax Provision	16,258,779
Non-Deductible Business Expense	473,282
Ice Storm Expense Amortization	132,681
Asbury 5 Yr Maint Amort	119,856
Injuries & Damages Accrual	567,227
Transaction Costs Capitalized for Tax	
Loss on Reacquired Debt	673,458
Deferred Fuel Costs	8,925,440
Iatan Deferred Charges	550,226
	27,700,949
Income Recorded on Books not Included in Return:	
Earnings of Subsidiary Companies Included	3,611,817
Plum Point Transmission Credits	37,320
SWPA Income Net of Depreciation Foregone	1,399,008
AFUDC in Excess of Tax Capitalized Interest	600,931
	5,649,076
Deductions on Return not Charged against Book Income:	
Depreciation Allowance in Excess of Books	(12,922,424)
Deductible Dividends (401K Plan)	
Amort of Interest Hedges (Net)	123,779
Bad Debts	(30,930)
Software Dev Costs	1,106,268
Misc Book Deferrals Expensed for Tax	5,013,540
Repair Allowance	14,979,977
Amort of Officers Liab Prem from Acquisition	83,533
FAS 87 Pension Expense	4,607,283
Deferred Rate Case Expense	399,405
2017 NOL Utilized	38,000,000
	51,360,431
Federal Tax Net Income (Expected for 2018)	94,581,344
Add State Benefit	(3,868,377)
Federal Net Taxable Income/(Loss)	90,712,967
Federal Income Tax (Expected 20.36%)	18,469,160
2017 Return to Accrual & Amended Returns	10,684,285
Estimated Current Federal Tax	29,153,445
Adjust - Other	(9,694,558)
Adjust - Missouri Tax Rate	(1,531,534)
Federal Current Tax Records	17,927,353

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1						
2	Federal Income			23,311,658	247,228	
3						
4	O.A.B. - 2017	94,985			94,985	
5	O.A.B. - 2018			256,852	156,257	
6	Unemployment - 2017	38			38	
7	Unemployment - 2018			468	437	
8						
9	State:					
10						
11	Arkansas Income	15,567			220,000	
12						
13	Unemployment - 2017		21		-21	
14	Unemployment - 2018			1,350	1,350	
15	Corp Franchise - 2017					
16	Corp Franchise - 2018			6,091	6,091	
17						
18	Kansas Income				-2,984	
19						
20	Corp Franchise -2017					
21	Corp Franchise -2018					
22	Real & Personal - 2017	17,965			17,965	
23	Real & Personal - 2018			34,908	17,455	
24	Unemployment - 2017	133			133	
25	Unemployment - 2018			17,943	17,943	
26	Use - 2017	750			750	
27	Use - 2018			10,441	10,002	
28						
29	Missouri Income	2,382,723		172,206		
30						
31	Unemployment - 2017	70			70	
32	Unemployment - 2018			-19,549	-19,673	
33	Corp Franchise - 2005					
34	Corp Franchise - 2017					
35	Corp Franchise - 2018			437	437	
36	Real & Personal - 2017	4,800			4,800	
37	Real & Personal - 2018			87,422	82,622	
38	Use - 2017	36,186			36,186	
39	Use - 2018			182,909	153,084	
40	Water Primacy Fee					
41	TOTAL	5,258,307	77	55,387,815	32,195,461	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/13/2019	End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1						
2	Oklahoma Income	35,000				
3						
4	Unemployment - 2018		56	264	208	
5	Corp Franchise - 2017					
6	Corp Franchise - 2018			22,654	22,654	
7						
8	Local:					
9						
10	Arkansas					
11	Real & Personal - 2017	254,571			254,571	
12	Real & Personal - 2018			447,021	167,116	
13	Franchise - 2017	13,333			13,333	
14	Franchise - 2018			218,202	202,435	
15						
16	Kansas					
17	Real & Personal - 2017	1,397,537			1,397,537	
18	Real & Personal - 2018			2,761,389	1,398,408	
19	Franchise - 2017	36,127			36,127	
20	Franchise - 2018			477,826	439,550	
21						
22	Missouri					
23	Real & Personal - 2017	-14,904			-14,904	
24	Real & Personal - 2018			17,379,119	17,296,452	
25	Franchise - 2017	720,223			720,223	
26	Franchise - 2018			9,356,402	8,561,492	
27	Merch-					
28						
29	Oklahoma					
30	Real & Personal - 2017	252,865			252,865	
31	Real & Personal - 2018			516,492	258,246	
32	Franchise - 2017	10,338			10,338	
33	Franchise - 2018			145,310	133,655	
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	5,258,307	77	55,387,815	32,195,461	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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
23,064,430		17,927,653			5,384,005	2
						3
						4
100,595		2,966,073			-2,709,221	5
						6
31		19,302			-18,834	7
						8
						9
						10
-204,433						11
						12
						13
		595			755	14
						15
		5,642			449	16
						17
2,984						18
						19
						20
						21
						22
17,453		34,769			139	23
						24
		7,911			10,032	25
						26
439					10,441	27
						28
2,554,929		-2,914,888			3,087,094	29
						30
						31
124		52,574			-72,123	32
						33
						34
		405			32	35
						36
4,800		87,074			348	37
						38
29,825					182,909	39
						40
28,450,584		50,201,839			5,185,976	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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
35,000						2
						3
		116			148	4
						5
		20,985			1,669	6
						7
						8
						9
						10
						11
279,905		445,241			1,780	12
						13
15,767		218,202				14
						15
						16
						17
1,362,981		2,750,391			10,998	18
						19
38,276		477,826				20
						21
						22
						23
82,667		17,309,897			69,222	24
						25
794,910		10,132,327			-775,925	26
						27
						28
						29
						30
258,246		514,434			2,058	31
						32
11,655		145,310				33
						34
						35
						36
						37
						38
						39
						40
28,450,584		50,201,839			5,185,976	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/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 Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	484,429			411413		
6	Adv Coal Credit	17,245,638			411004	1,808,382	1,808,382
7							
8	TOTAL	17,730,067				1,808,382	1,808,382
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12	4%	178					
13	10%	3,930			411423		
14							
15	Total	4,108					
16							
17	Tot Company	17,734,175				1,808,382	1,808,382
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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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
			3
			4
484,429			5
17,245,638			6
			7
17,730,067			8
			9
			10
			11
178			12
3,930			13
			14
4,108			15
			16
17,734,175			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
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			43
			44
			45
			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Accounts Payable - Unpresented Chk	145,768		45,127	62,741	163,382
2						
3	Plum Point Transmission Cr	845,912		37,320		808,592
4						
5	Deferred Revenue - Land Lease	18,208		66,947	69,432	20,693
6						
7	Comm Action Agencies	1,500,000		450,000		1,050,000
8						
9	Director Def Comp	1,844,161		603,572		1,240,589
10						
11	Severance	1,672,583				1,672,583
12						
13	Deferred Revenue - Other			3,600	6,200	2,600
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	6,026,632		1,206,566	138,373	4,958,439

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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 rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	27,365,522		605,580
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	27,365,522		605,580
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)	27,365,522		605,580
18	Classification of TOTAL			
19	Federal Income Tax	23,953,810		502,631
20	State Income Tax	3,411,711		102,949
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
		Debits		Credits				
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
					-9,804,184	16,955,758	4
							5
							6
							7
					-9,804,184	16,955,758	8
							9
							10
							11
							12
							13
							14
							15
							16
					-9,804,184	16,955,758	17
							18
					-8,137,472	15,313,707	19
					-1,666,711	1,642,051	20
							21

NOTES (Continued)

Schedule Page: 272 Line No.: 4 Column: c

Deferred Tax Computation:
2018 Tax Amortization

Estimated Book Amortization:	**Basis**	**Avg Rate**	**Est Book Amort**	
2009 Vintage Amort-Iatan	37,531,460	0.0270	1,013,349	
2010 Vintage Amort-Iatan II	31,446,820	0.0158	496,860	
2008 Vintage Amort-Asbury	21,721,378	0.0445	966,601	
Estimated 2018 Book Amort				2,476,810
2018 Basis for Deferral				(2,476,810)
Multiply by Incremental Tax Rate				24.45%
2018 PC Amortization Deferred Tax (Page 272-Line 4 Col (c))				(605,580)
Federal (502,632)				
State (102,949)				
(605,580)				
Balance EOY 2017 FERC Acct 281				27,365,522
Divide by Incremental Tax Rate 2017				38.10%
Gross up Amount for Acct 281				71,825,517
Multiply by Incremental Tax Rate 2018				24.45%
Adjusted Balance for FERC Acct 281 due to Tax Reform				17,561,339
Balance EOY 2017 Ferc Acct 281				27,365,522
Adjusted 2018 Balance Ferc Acct 281				17,561,339
Adjustment Needed for 2018				9,804,183
Federal Amount			20.36%	8,137,472
State Amount			4.09%	1,666,711

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	267,151,668		-17,016,660
3	Gas			
4	Water	1,860,532		
5	TOTAL (Enter Total of lines 2 thru 4)	269,012,200		-17,016,660
6	Non-utility			
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	269,012,200		-17,016,660
10	Classification of TOTAL			
11	Federal Income Tax	242,269,700		-14,170,110
12	State Income Tax	26,742,501		-2,846,550
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
		Various	28,105,724	Various		256,062,604	2
							3
						1,860,532	4
			28,105,724			257,923,136	5
							6
							7
							8
			28,105,724			257,923,136	9
							10
			23,404,193			233,035,617	11
			4,701,530			24,887,521	12
							13

NOTES (Continued)

Schedule Page: 274 Line No.: 2 Column: b

Includes Additional Jurisdictional Accruals:

Description	Period	Balance Beg of Yr	Debited to 410.1	Credited to 411.1	Balance End of Yr
OK Juris	Prior to 2012	147,755			147,755
KS Juris	Prior to 2012	646,629			646,629
FERC Juris	Prior to 2012	339,226			339,226
		1,133,610			**1,133,610**

	Beg of Yr	End of Yr	
L.D. Electric	294,443,017	273,108,942	
Reclassify PC Amort	(27,365,522)	(16,955,758)	Pg 273
Additional (Above)	1,133,610	1,133,610	
Misc Yr End Adj	(974,458)	(1,157,638)	
A/C 282130 & 282135	(84,938)	(66,549)	
Pg 274-275 Line 2	**267,151,710**	**256,062,606**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Asbury #1	31,747	-29,305	
4	Loss on Reacquired Debt	2,059,344		164,660
5	Def Tax Liability-FAS 109	13,333,421		
6	Def Tax Liability-FAS 158	15,457,806		
7	Licensed Software	2,447,372	-244,942	
8	Other	29,929,914	-2,970,601	4,556,792
9	TOTAL Electric (Total of lines 3 thru 8)	63,259,604	-3,244,848	4,721,452
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)	63,259,604	-3,244,848	4,721,452
20	Classification of TOTAL			
21	Federal Income Tax	59,256,616	-2,702,049	3,931,647
22	State Income Tax	4,002,988	-542,799	789,805
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					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
		Various	2,703			-261	3
		Various	175,366			1,719,318	4
		182311	3,619,922			9,713,499	5
		190356	2,029,230			13,428,576	6
		Various	114,320			2,088,110	7
				182319	-1,592,579	20,809,942	8
			5,941,541		-1,592,579	47,759,184	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
			5,941,541		-1,592,579	47,759,184	19
							20
			4,947,640		-1,326,172	46,349,108	21
			993,901		-266,407	1,410,076	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 8 Column: a

Detail to Other (Line 8):

	Beginning Balance	Debited to 410.1	Credited to 411.1	Acct	Amount	Ending Balance
283917 Def Tax Liab- Equity AFUDC	13,491,784			182319	(819,894)	12,671,890
283123 Hedging Trans	1,544,100		(636,058)		(737,258)	1,442,900
283139 Def Fuel Costs	3,220,374	(2,970,601)			(429,623)	(179,850)
283921 Def Ice Storm Exp	93,923		32,441		(7,998)	53,484
283116 Iatan Def Chrgs	3,632,494		5,160,409		1,075,772	(452,143)
283366 Def ITC-Basis Reduction Iatan	5,215,873				(440,986)	4,774,887
283103 Repair Allowance	2,731,366				(232,592)	2,498,773
Totals to Line 8	**29,929,914**	**(2,970,601)**	**4,556,792**		**(1,592,579)**	**20,809,942**

State/Federal Allocation:

State	4.09%
Federal	20.36%
Total	**24.45%**

Schedule Page: 276 Line No.: 8 Column: b

Other:

		Beg Bal	End Bal
283917	Deferred Tax Liab - Equity AFUDC	13,491,784	12,671,890
283123	Hedging Transactions	1,544,100	1,442,900
283139	Deferred Fuel Costs	3,220,374	(179,850)
283921	Deferred Ice Storm Expense	93,923	53,484
283116	Iatan Deferred Charges	3,632,494	(452,143)
283366	Def ITC Tax Basis Reduction-Iatan	5,215,873	4,774,887
283103	Repair Allowance	2,731,366	2,498,773
Total - Other		**29,929,914**	**20,809,942**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/13/2019	End of 2018/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Deferred Tax Liab - FAS 109 (Amortized over the	59,690,405	190	13,018,449	10,104,481	56,776,437
2	various remaining tax lives of the assets.)					
3						
4	Gain on Interest Rate Derivative Related to 6.7%	2,691,311	428	169,978		2,521,333
5	Senior Notes due 11/15/33 (Amortized over the					
6	life of the Senior Notes)					
7						
8	TCR	1,117,134	175, 555	6,227,058	5,109,924	
9						
10	MO FAS 106 Elec Over Rec'd Amt ER-2006-0315	2,461,232	926	535,137	1,682,328	3,608,423
11						
12	KS ECA-ACA Over Recovered 05-EPDE-980-RTS	296,179	501	870,429	574,250	
13						
14	Reg OPEB Costs Amortization ER-2004-0570	35,204	926	35,442	238	
15						
16	Def MO Fuel Cost ER-2008-0093		182, 254	2,634,840	3,694,940	1,060,100
17						
18	MO FAS - Unrealized Deriv ER-2008-0093	48,393	414, 555	54,116	18,107	12,384
19						
20	Fuel Construction Acctg Iatan2 ER-2010-0130	7,417,800	501, 506	160,172		7,257,628
21						
22	SWPA Ozark Beach - Arkansas	637,377	501	14,737		622,640
23						
24	SWPA Ozark Beach - Kansas	511,830	501	125,973		385,857
25						
26	SWPA Ozark Beach - Missouri	6,227,374	501	2,290,445		3,936,929
27						
28	SWPA Ozark Beach - Oklahoma	281,860	501	69,429		212,431
29						
30	SWPA Ozark Beach - FERC	1,739,283	501			1,739,283
31						
32	Reclass - Current	3,064,063	254	3,064,063	3,066,385	3,066,385
33						
34	Reclass - Noncurrent	(3,064,063)	254	3,066,385	3,064,063	-3,066,385
35						
36	Def MO Fuel Cost Recovery ER-2008-0093		501		2,777,863	2,777,863
37						
38	OK FAS 106 Over Recd Amt	101,550		24,055	44,518	122,013
39	Def OK Fuel Cost PUD 201100082	13,943	501	13,943		
40						
41	TOTAL	224,028,030		43,902,925	63,592,672	243,717,777

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	KS ECA Docket 05-EPDE-980-RTS	106,241			327,060	433,301
2						
3	MO Return of Excess Def Tx 2017	140,650,914	182	11,265,550	18,567,829	147,953,193
4						
5	Rate Ref 2017 Tax Ref AR			262,724	372,436	109,712
6						
7	Rate Ref 2017 Tax Ref KS				1,229,467	1,229,467
8						
9	Rate Ref 2017 Tax Ref MO				11,728,453	11,728,453
10						
11	Rate Ref 2017 Tax Ref OK				590,339	590,339
12						
13	MO FAS 87 Pension				639,991	639,991
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	224,028,030		43,902,925	63,592,672	243,717,777

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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	275,267,320	238,334,588
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	187,859,144	175,235,495
5	Large (or Ind.) (See Instr. 4)	97,911,615	88,720,987
6	(444) Public Street and Highway Lighting	4,349,508	4,173,789
7	(445) Other Sales to Public Authorities	12,328,707	11,254,224
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	352,862	304,189
10	TOTAL Sales to Ultimate Consumers	578,069,156	518,023,272
11	(447) Sales for Resale	53,683,164	52,436,286
12	TOTAL Sales of Electricity	631,752,320	570,459,558
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	631,752,320	570,459,558
15	Other Operating Revenues		
16	(450) Forfeited Discounts	2,104,420	1,737,301
17	(451) Miscellaneous Service Revenues	257,576	109,623
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	1,110,516	1,058,952
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	1,099,871	1,005,965
22	(456.1) Revenues from Transmission of Electricity of Others		
23	(457.1) Regional Control Service Revenues	9,876,044	8,339,934
24	(457.2) Miscellaneous Revenues		
25	(407) Rate Ref 2017 Tax Reform	-13,635,388	
26	TOTAL Other Operating Revenues	813,039	12,251,775
27	TOTAL Electric Operating Revenues	632,565,359	582,711,333

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
2,002,307	1,745,673	145,798	144,718	2
				3
1,614,542	1,560,479	24,746	24,644	4
1,139,279	1,080,150	352	350	5
24,743	24,371	523	504	6
107,636	102,228	1,581	1,578	7
				8
3,015	2,634	41	41	9
4,891,522	4,515,535	173,041	171,835	10
345,155	325,820	4	4	11
5,236,677	4,841,355	173,045	171,839	12
				13
5,236,677	4,841,355	173,045	171,839	14

Line 12, column (b) includes $ 5,558,624 of unbilled revenues.

Line 12, column (d) includes 86,050 MWH relating to unbilled revenues

Schedule Page: 300   Line No.: 14   Column: f

Average Number of Customers:

173,045	Ferc Pg 301
1	Southwest Power Pool
1	Westar
173,047	**Ferc Pg 304 Col (d)**

Schedule Page: 300   Line No.: 17   Column: b

Misc Service Revenue:

2,656.00	451031 Reconnect Charges - AR
4,720.00	451032 Reconnect Charges - KS
113,555.00	451033 Reconnect Charges - MO
3,218.00	451034 Reconnect Charges - OK
3,451.19	451210 Other Misc Revenue - AR
5,399.53	451220 Other Misc Revenue - KS
120,692.85	451230 Other Misc Revenue - MO
3,883.43	451240 Other Misc Revenue - OK
257,576.00	**Total**

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

Other Electric Revenue:

18,070.55	456010	Other Electric Revenue - AR
1,650.38	456020	Other Electric Revenue - KS
333,551.13	456030	Other Electric Revenue - MO
735.57	456040	Other Electric Revenue - OK
260,905.02	456075	REC Revenue
253,799.76	456081	Ot Elec Rev Off Sys - Monett
100,885.92	456082	Ot Elec Rev Off Sys - Mt Vernon
22,788.00	456083	Ot Elec Rev Off Sys - Chetopa
70,165.32	456084	Ot Elec Rev Off Sys - Lockwood
929.52	456091	Plum Pt Transmission Credits - AR
1,823.28	456092	Plum Pt Transmission Credits - KS
33,593.64	456093	Plum Pt Transmission Credits - MO
973.20	456094	Plum Pt Transmission Credits - OK
1,099,871.29	**Total**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Scheduling Fees	19,691	163,623	357,815	527,906
2	Losses				
3	Off-System Distribution	5,333	10,665	15,998	21,331
4	Off-System Transmission	269,489	592,171	1,011,490	1,313,068
5	Reactive Supply & Voltage	21,858	40,922	65,441	86,350
6	Regulation Adjustment				
7	Reserve - Spinning				
8	Reserve - Supplemental				
9	Network Revenue	481,600	968,700	1,597,091	2,225,993
10	Funding of Transmission Upgrades	1,452,381	2,967,652	4,326,753	5,701,396
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
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32					
33					
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37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	2,250,352	4,743,733	7,374,588	9,876,044

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/13/2019	End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RESIDENTIAL					
2	MS Miscellaneous Service					
3	PL Private Lighting	5,500	1,969,915	162	33,951	0.3582
4	RGL Residential Pilot	10,470	1,331,663	774	13,527	0.1272
5	RG Residential Service	1,929,711	266,541,359	141,345	13,652	0.1381
6	RG Rider W/Water Heater	11,351	1,208,802	752	15,094	0.1065
7	RH Residential All Electric	54,246	5,134,829	2,765	19,619	0.0947
8	SH SM Heating					
9	Unbilled Revenue	-8,962	-918,917			0.1025
10	Net Metering	-9	-331			0.0368
11	Subtotal	2,002,307	275,267,320	145,798	13,733	0.1375
12						
13	COMMERCIAL AND INDUSTRIAL:					
14	CB Commercial	351,004	51,234,848	18,922	18,550	0.1460
15	CP Cogeneration Purchase					
16	GP General Power	890,509	93,867,823	1,815	490,639	0.1054
17	LP Large Power	718,898	62,612,512	38	18,918,368	0.0871
18	LS Special Lighting	398	68,484	73	5,452	0.1721
19	MS Miscellaneous Service	1	392	1	1,000	0.3920
20	RH Residential All Electric					
21	RG Residential Service	2	344	1	2,000	0.1720
22	PFM Feed Mill and Grain Elevator	386	72,485	10	38,600	0.1878
23	PL Private Lighting	10,293	3,075,459	149	69,081	0.2988
24	Praxair	63,666	4,164,703	1	63,666,000	0.0654
25	PT Transmission	183,119	13,400,004	14	13,079,929	0.0732
26	SH Small Heating	90,498	11,557,209	3,086	29,325	0.1277
27	TEB All Electric Building	379,429	41,483,857	988	384,037	0.1093
28	Net Metering	-45	-1,180			0.0262
29	Unbilled Revenue	65,663	4,233,819			0.0645
30	Subtotal	2,753,821	285,770,759	25,098	109,723	0.1038
31						
32	PUBLIC ST & HWY LIGHTING:					
33	CB Commercial	2,259	400,391	417	5,417	0.1772
34	GP General Power	664	77,720	2	332,000	0.1170
35	LS Special Lighting	609	106,941	93	6,548	0.1756
36	MS Miscellaneous	136	14,754	2	68,000	0.1085
37	PL Private Lighting	113	29,922	1	113,000	0.2648
38	SH Small Heating	18	2,625	2	9,000	0.1458
39	SPL Municipal Street Lighting	18,794	3,423,545	6	3,132,333	0.1822
40	Unbilled Revenue	2,151	293,610			0.1365
41	TOTAL Billed	5,236,677	631,752,320	173,047	30,262	0.1206
42	Total Unbilled Rev.(See Instr. 6)	-86,050	-5,558,624	0	0	0.0646
43	TOTAL	5,150,627	626,193,696	173,047	29,764	0.1216

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Subtotal	24,744	4,349,508	523	47,312	0.1758
2						
3	OTHER SALES TO PUB AUTH:					
4	CB Commerical	21,174	2,989,463	1,322	16,017	0.1412
5	GP General Power	76,852	8,201,861	190	404,484	0.1067
6	LS Special Lighting	58	7,716	1	58,000	0.1330
7	Net Metering					
8	PL Private Lighting	15	5,075			0.3383
9	RG Residential Service		59			
10	SH Small Heating	1,645	197,341	47	35,000	0.1200
11	TEB All Electric Building	7,891	927,192	21	375,762	0.1175
12	Subtotal	107,635	12,328,707	1,581	68,080	0.1145
13						
14	INTERDEPARTMENTAL	3,015	352,862	41	73,537	0.1170
15	Subtotal	3,015	352,862	41	73,537	0.1170
16						
17	SALES FOR RESALE - ELECTRIC					
18	Ameren (AEM)					
19	Ameren (AMRN)					
20	American Electric Power					
21	Aquila					
22	Arkansas Electric					
23	Board of Public Utilities					
24	Calpine					
25	Cargile-Alliant					
26	Central Louisiana Electric					
27	City of Carthage					
28	City Utilities of Springfield					
29	Constellation					
30	Duke Energy Marketing & Trading					
31	Endure Energy					
32	Entergy					
33	Fortis Energy					
34	Golden Spread					
35	Independence Power & Light					
36	Kansas City Power & Light					
37	Kansas Electric Power Coop					
38	Kansas Energy					
39	Kaw Valley Electric					
40	Lagan					
41	TOTAL Billed	5,236,677	631,752,320	173,047	30,262	0.1206
42	Total Unbilled Rev.(See Instr. 6)	-86,050	-5,558,624	0	0	0.0646
43	TOTAL	5,150,627	626,193,696	173,047	29,764	0.1216

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	LaFayette Utilities					
2	Lincoln Electrical Systems					
3	Louisiana Electric & Power					
4	Macquaire Energy					
5	MISO					
6	Missouri Public Service					
7	Nebraska Public Power District					
8	Oklahoma Gas & Electric					
9	Oklahoma Municipal Power Auth					
10	Omaha Public Power Dist					
11	Rainbow Energy					
12	South Mississippi Electric					
13	Southern Company					
14	Southwest Power Administration					
15	Southwest Power Pool		31,386,700	1		
16	Sunflower Electric					
17	Tenaska					
18	The Energy Authority					
19	Trademark Energy (Kansas Energy)					
20	West Memphis					
21	Westar		32,442	1		
22	Western Area Power Administration					
23	Western Farmers					
24	WPEK					
25	Xcel Energy					
26	Subtotal		31,419,142	2		
27						
28	SALES FOR RESALE-AGENCY					
29	AEC					
30	Grand River Dam Authority					
31	Subtotal					
32	SALES FOR					
33	City of Monett	231,802	14,325,955	1	231,802,000	0.0618
34	City of Mt Vernon	66,060	4,427,033	1	66,060,000	0.0670
35	City of Lockwood	10,652	783,027	1	10,652,000	0.0735
36	City of Chetopa	9,443	777,894	1	9,443,000	0.0824
37	Unbilled Revenue	27,198	1,950,113			0.0717
38	Subtotal	345,155	22,264,022	4	86,288,750	0.0645
39						
40	Total Sales	5,236,677	631,752,320	173,047	30,262	0.1206
41	TOTAL Billed	5,236,677	631,752,320	173,047	30,262	0.1206
42	Total Unbilled Rev.(See Instr. 6)	-86,050	-5,558,624	0	0	0.0646
43	TOTAL	5,150,627	626,193,696	173,047	29,764	0.1216

Schedule Page: 304 Line No.: 1 Column: a

Fuel Adjustment Revenues:

Residential	ECR/ECA/ACA/Fuel	FAC Revenues	FERC Fuel	Total Company
CP Cogeneration Purchase				
MS Miscellaneous Service				
NM Net Metering				
PL Private Lighting	28,001.19	19,506.91		47,508.10
RGL Residential Pilot Prog		42,493.03		42,493.03
RG Residential Service	3,261,726.86	8,083,461.06		11,345,187.92
RG Rider W/Water Heater	227,671.42			227,671.42
RH Residential All Electric	1,182,423.94			1,182,423.94
SH Small Heating				
Total Residential	**4,699,823.41**	**8,145,461.00**		**12,845,284.41**
Commercial and Industrial				
CB Commercial	947,407.82	1,473,157.15		2,420,564.97
CP Cogeneration Purchase				
GP General Power	1,929,978.29	3,929,548.16		5,859,526.45
LP Large Power		3,607,974.17		3,607,974.17
LS Special Lighting	1,740.17	1,176.13		2,916.30
MS Miscellaneous Service		9.10		9.10
NM Net Metering				
PF Electric Furnace				
PFM Feed Mill and Grain Elevator		2,018.19		2,018.19
PL Private Lighting	38,715.35	39,635.56		78,350.91
Praxair		315,223.74		315,223.74
PT Transmission	4,208,433.98			4,208,433.98
RG Residential Service		18.74		18.74
RH Residential All Electric				
SH Small Heating	54,650.18	392,696.49		447,346.67
TEB All Electric Building	277,468.17	1,704,382.30		1,981,850.47
Total Commercial & Industrial	**7,458,393.96**	**11,465,839.73**		**18,924,233.69**
Public St and Hwy Lighting				
CB Commercial	5,711.49	10,069.11		15,780.60
GP General Power		3,650.59		3,650.59
LS Special Lighting	1,482.50	2,408.47		3,890.97
MS Miscellaneous		613.59		613.59
PL Private Lighting	432.53	431.83		864.36
SH Small Heating		61.81		61.81
RG Residential Service				
SPL Municipal Street Lighting	56,891.29	78,036.80		134,928.09
Total Public St & Hwy Lighting	**64,517.81**	**95,272.20**		**159,790.01**
Other Sales to Public Auth				
CB Commercial	103,762.60	75,712.92		179,475.52
GP General Power	145,863.06	334,830.22		480,693.28
LS Special Lighting	1,052.41	12.00		1,064.41
NM Net Metering		57.91		57.91
PL Private Lighting	56.15	.77		56.92
RG Residential Service				
SH Small Heating	3,734.10	6,180.23		9,914.33
TEB All Electric Building	3,322.14	35,914.68		39,236.82
Total Other Sales to Public Auth	**257,790.46**	**452,708.73**		**710,499.19**
Interdepartmental				
CB Commercial	3,552.17	6,393.81		9,945.98
GP General Power	70.59	6,657.59		6,728.18
PL Private Lighting		14.08		14.08
Total Interdepartmental	**3,622.76**	**13,065.48**		**16,688.24**
Sales for Resale-Municipalities				
City of Monett			4,828,151.65	4,828,151.65
City of Mt Vernon			1,376,495.71	1,376,495.71
City of Lockwood			222,083.60	222,083.60
City of Chetopa			198,053.69	198,053.69
Total Sales for Resale-Munic			**6,624,784.65**	**6,624,784.65**
Total Fuel Adjustment Revenues	**12,484,148.40**	**20,172,347.14**	**6,624,784.65**	**39,281,280.19**

Name of Respondent The Empire District Electric Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/13/2019	Year/Period of Report End of 2018/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	REQUIREMENT SALES:					
2	Municipalities:					
3	City of Monett	RQ	GFR Tariff	39.068	44.121	39.203
4	City of Mount Vernon	RQ	GFR Tariff	12.124	12.548	12.129
5	City of Lockwood	RQ	GFR Tariff	2.162	2.358	2.136
6	City of Chetopa	RQ	GFR Tariff	1.971	2.040	1.979
7						
8	NON-REQUIREMENT SALES:					
9	Non-Associated Utilities:					
10	Entergy	OS	EC-WSPP			
11	Kansas City Power & Light	OS	EC-WSPP			
12	Nebraska Public Power Dist - NPPD	OS	EC-WSPP			
13	Westar Energy Inc	OS	EC-WSPP			
14	Westar Energy Inc	OS	ES			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (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	American Electric Power	OS	ES			
2	American Electric Power	OS	EC-WSPP			
3	Oklahoma Gas & Electric	OS	EC-WSPP			
4	Southwestern Public Service Co	OS	EC-WSPP			
5	KCPL - GMO	OS	EC-WSPP			
6	Omaha Public Power District	OS	EC-WSPP			
7	Lincoln Electric Systems	OS	EC-WSPP			
8	Cleco Power LLC	OS	EC-WSPP			
9	Lafayette Utilities System	OS	EC-WSPP			
10	City Utilities of Springfield	OS	EC-WSPP			
11						
12	Cooperatives:					
13	Associated Electric Cooperative Inc	OS	EC-WSPP			
14	Associated Electric Cooperative Inc	OS	ES			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Western Farmers Electric Cooperative	OS	EC-WSPP			
2	South Mississippi Electric Power Assoc	OS	EC-WSPP			
3	Louisiana Generating LLC	OS	EC-WSPP			
4	Sunflower Electric Power Corp	OS	EC-WSPP			
5	Arkansas Electric Coop Corp	OS	EC-WSPP			
6	Golden Spread Electric Coop	OS	EC-WSPP			
7	Other Public Authorities:					
8	Western Area Power Admin (WAUE)	OS	EC-WSPP			
9	OK Municipal Power Authority (OMPA)	OS	EC-WSPP			
10	Grand River Dam Authority	OS	EC-WSPP			
11	Grand River Dam Authority	OS	ES-No. 0094			
12	Board of Public Utilities	SF	EC-WSPP			
13	Southwestern Power Admin	OS	ES			
14	Louisiana Electric & Power (LEPA)	OS	EC-WSPP			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
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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)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Independence Power & Light	OS	EC-WSPP			
2						
3	Power Brokers:					
4	Cargil-Alliant	OS	EC-WSPP			
5	Endure Energy	OS	EC-WSPP			
6	Calpine Energy Management	OS	EC-WSPP			
7	Tenaska	OS	EC-WSPP			
8	The Energy Authority	OS	EC-WSPP			
9	Rainbow Energy Marketing Corp	OS	EC-WSPP			
10	Macquarie Energy LLC	OS	EC-WSPP			
11	Southern Company Services Inc	OS	EC-WSPP			
12	Constellation	OS	EC-WSPP			
13						
14	Regional Transmission Organizations:					
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
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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.
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IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Midwest ISO	OS				
2	SW Powerpool & IMS	OS				
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,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
					2
251,582	9,948,592	5,786,270		15,734,862	3
71,612	3,174,964	1,651,906		4,826,870	4
11,577	584,490	267,397		851,887	5
10,384	605,204	245,199		850,403	6
					7
					8
					9
					10
					11
					12
			32,442	32,442	13
					14
345,155	14,313,250	7,950,772	0	22,264,022	
1,521,843	0	31,386,700	32,442	31,419,142	
1,866,998	**14,313,250**	**39,337,472**	**32,442**	**53,683,164**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
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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)
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7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
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10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
345,155	14,313,250	7,950,772	0	22,264,022	
1,521,843	0	31,386,700	32,442	31,419,142	
1,866,998	**14,313,250**	**39,337,472**	**32,442**	**53,683,164**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

SALES FOR RESALE (Account 447) (Continued)

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7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
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10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
345,155	14,313,250	7,950,772	0	22,264,022	
1,521,843	0	31,386,700	32,442	31,419,142	
1,866,998	**14,313,250**	**39,337,472**	**32,442**	**53,683,164**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
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7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
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					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
345,155	14,313,250	7,950,772	0	22,264,022	
1,521,843	0	31,386,700	32,442	31,419,142	
1,866,998	**14,313,250**	**39,337,472**	**32,442**	**53,683,164**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
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MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
1,521,843		31,386,700		31,386,700	2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
345,155	14,313,250	7,950,772	0	22,264,022	
1,521,843	0	31,386,700	32,442	31,419,142	
1,866,998	**14,313,250**	**39,337,472**	**32,442**	**53,683,164**	

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

On these four municipalities on lines 3,4,5,& 6, column (d),(e), & (f) are actual demand from customer's bills after adjustments for substation and transmission losses. Based on a 60 minute CP demand. Column (e) is based on a 60 minute NCP demand period, including 2.71% for transmission losses. The average monthly CP demand (column f) includes transmission losses of 2.7885% based on a 60 minute CP demand period.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	2,113,934	2,112,671
5	(501) Fuel	50,063,500	27,660,128
6	(502) Steam Expenses	2,105,238	2,735,031
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,672,309	1,289,493
10	(506) Miscellaneous Steam Power Expenses	2,807,809	3,190,633
11	(507) Rents	44,439	55,185
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	58,807,229	37,043,141
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,215,745	1,064,161
16	(511) Maintenance of Structures	1,383,033	1,523,564
17	(512) Maintenance of Boiler Plant	5,314,682	5,708,788
18	(513) Maintenance of Electric Plant	2,049,288	1,757,306
19	(514) Maintenance of Miscellaneous Steam Plant	2,422,564	1,027,928
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	12,385,312	11,081,747
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	71,192,541	48,124,888
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	47,833	57,857
45	(536) Water for Power		
46	(537) Hydraulic Expenses	41,213	20,705
47	(538) Electric Expenses	50,402	31,220
48	(539) Miscellaneous Hydraulic Power Generation Expenses	306,364	224,965
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	445,812	334,747
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	39,817	39,706
54	(542) Maintenance of Structures	45,404	53,780
55	(543) Maintenance of Reservoirs, Dams, and Waterways	224,454	162,615
56	(544) Maintenance of Electric Plant	40,902	38,438
57	(545) Maintenance of Miscellaneous Hydraulic Plant	82,963	109,491
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	433,540	404,030
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	879,352	738,777

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The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,020,091	842,283
63	(547) Fuel	67,912,729	70,968,633
64	(548) Generation Expenses	4,010,954	3,621,047
65	(549) Miscellaneous Other Power Generation Expenses	1,079,272	1,177,183
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	74,023,046	76,609,146
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	853,053	781,280
70	(552) Maintenance of Structures	430,895	275,454
71	(553) Maintenance of Generating and Electric Plant	12,755,634	11,964,913
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	746,678	754,557
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	14,786,260	13,776,204
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	88,809,306	90,385,350
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	60,713,947	35,628,948
77	(556) System Control and Load Dispatching	4,003,497	3,334,504
78	(557) Other Expenses	411,306	512,466
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	65,128,750	39,475,918
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	226,009,949	178,724,933
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	316,450	434,636
84			
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System		
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	581,352	607,661
89	(561.5) Reliability, Planning and Standards Development	11,980	27,322
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	491,677	496,319
94	(563) Overhead Lines Expenses	45,712	47,375
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	19,353,916	18,890,823
97	(566) Miscellaneous Transmission Expenses	-20,672	344,270
98	(567) Rents	175	175
99	TOTAL Operation (Enter Total of lines 83 thru 98)	20,780,590	20,848,581
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	102,227	132,282
102	(569) Maintenance of Structures	10,012	16,256
103	(569.1) Maintenance of Computer Hardware		
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	1,644,242	1,566,856
108	(571) Maintenance of Overhead Lines	2,925,458	2,461,600
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	4,681,939	4,176,994
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	25,462,529	25,025,575

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		
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		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
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)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,204,479	1,261,929
135	(581) Load Dispatching		
136	(582) Station Expenses	216,980	203,644
137	(583) Overhead Line Expenses	1,389,707	1,301,207
138	(584) Underground Line Expenses	827,305	915,396
139	(585) Street Lighting and Signal System Expenses	39,618	43,759
140	(586) Meter Expenses	3,004,385	3,047,591
141	(587) Customer Installations Expenses	262,487	212,489
142	(588) Miscellaneous Expenses	1,388,858	1,499,715
143	(589) Rents	2,302	2,766
144	TOTAL Operation (Enter Total of lines 134 thru 143)	8,336,121	8,488,496
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	264,303	268,971
147	(591) Maintenance of Structures	150,784	71,794
148	(592) Maintenance of Station Equipment	2,239,104	1,720,991
149	(593) Maintenance of Overhead Lines	13,470,172	12,262,213
150	(594) Maintenance of Underground Lines	799,230	677,782
151	(595) Maintenance of Line Transformers	436,584	445,242
152	(596) Maintenance of Street Lighting and Signal Systems	369,505	318,133
153	(597) Maintenance of Meters	336,212	368,940
154	(598) Maintenance of Miscellaneous Distribution Plant	208,499	268,086
155	TOTAL Maintenance (Total of lines 146 thru 154)	18,274,393	16,402,152
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	26,610,514	24,890,648
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	824,740	752,325
160	(902) Meter Reading Expenses	2,073,046	2,044,086
161	(903) Customer Records and Collection Expenses	3,918,395	3,761,593
162	(904) Uncollectible Accounts	2,505,193	1,664,572
163	(905) Miscellaneous Customer Accounts Expenses	173,713	131,180
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	9,495,087	8,353,756

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	208,399	204,534
168	(908) Customer Assistance Expenses	4,343,041	3,694,068
169	(909) Informational and Instructional Expenses	127,302	121,778
170	(910) Miscellaneous Customer Service and Informational Expenses	16,857	15,428
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	4,695,599	4,035,808
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	157,792	158,081
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses	485	
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	158,277	158,081
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	10,579,796	10,145,376
182	(921) Office Supplies and Expenses	3,765,646	4,672,371
183	(Less) (922) Administrative Expenses Transferred-Credit	10,768,126	6,593,008
184	(923) Outside Services Employed	20,698,558	14,651,707
185	(924) Property Insurance	2,434,207	2,929,932
186	(925) Injuries and Damages	2,323,491	1,006,949
187	(926) Employee Pensions and Benefits	23,009,411	23,913,454
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	1,208,979	1,340,377
190	(929) (Less) Duplicate Charges-Cr.	293,200	276,978
191	(930.1) General Advertising Expenses	13,645	13,423
192	(930.2) Miscellaneous General Expenses	651,027	725,457
193	(931) Rents	9,091	42,035
194	TOTAL Operation (Enter Total of lines 181 thru 193)	53,632,525	52,571,095
195	Maintenance		
196	(935) Maintenance of General Plant	632,928	592,028
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	54,265,453	53,163,123
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	346,697,408	294,351,924

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	NON ASSOCIATED UTILITIES:					
2	Entergy	OS	ES			
3	Kansas City Power & Light Co	OS	EC-WSPP			
4	Westar Energy Inc	OS	EC-WSPP			
5	Westar Energy Inc	OS	SE			
6	City Utilities of Springfield	OS	EC-WSPP			
7	American Electric Power	OS	ES			
8	American Electric Power	OS	EC-WSPP			
9	Oklahoma Gas & Electric	OS	EC-WSPP			
10	KCPL-GMO	OS	EC-WSPP			
11	Ameren-UE	OS	EC-WSPP			
12	Xcel Energy-Southwestern Pub Serv Co	OS	EC-WSPP			
13	Cleco Power LLC	OS	EC-WSPP			
14	Plum Point Energy Associates	LU	EC-WSPP			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Lafayette Utilities System	OS	EC-WSPP			
2	Omaha Public Power	OS	EC-WSPP			
3	Independence Power & Light	OS	EC-WSPP			
4	Nebraska Public Power Dist-NPPD	OS	EC-WSPP			
5	Lincoln Electric System	OS	EC-WSPP			
6						
7	COOPERATIVES:					
8	Arkansas Electric coop (AECC)	OS	EC-WSPP			
9	Associated Electric Coop	OS	EC-WSPP			
10	Associated Electric Coop	OS	ES			
11	Western Farmers Electric	OS	EC-WSPP			
12	South Mississippi Electric Power Assoc	OS	EC-WSPP			
13	Louisiana Generating LLC	OS	EC-WSPP			
14	Golden Spread Electric Coop	OS	EC-WSPP			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	OTHER PUBLIC AURTHORITY:					
2	Grand River Dam Authority	OS	EC-WSPP			
3	Grand River Dam Authority	OS	ES			
4	Board of Public Utilities	OS	EC-WSPP			
5	Western Area Power Admin	OS	EC-WSPP			
6	Oklahoma Municipal Power	OS	EC-WSPP			
7	Southwest Power Admin Auth	OS	EC-WSPP			
8	Sunflower Electric Power Corporation	OS	EC-WSPP			
9	Louisiana Electric & Power	OS	EC-WSPP			
10	North Little Rock	OS	EC-WSPP			
11	POWER BROKERS:					
12	Endure Energy	OS	EC-WSPP			
13	EDP Renewables	OS	EC-WSPP			
14	The Energy Authority	OS	EC-WSPP			
	Total					

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.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Tenaska Power Service	OS	EC-WSPP			
2	Cargill-Alliant Energy	OS	EC-WSPP			
3	Rainbow Energy	OS	EC-WSPP			
4	Avangrid	LF				
5	Constellation	OS	EC-WSPP			
6	Southwest Power Pool	OS	Sch 4A-SPP Tariff			
7	Third Party Imbalance	OS				
8	PJM	OS				
9	Midwest ISO	OS				
10						
11						
12						
13						
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 monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
356,056			11,072,855	9,480,750		20,553,605	14
1,707,924			11,072,855	44,531,168		55,604,023	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
							2
							3
							4
							5
							6
							7
							8
				66,237		66,237	9
							10
							11
							12
							13
							14
1,707,924			11,072,855	44,531,168		55,604,023	

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.
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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
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
309,259				12,078,230		12,078,230	13
							14
1,707,924			11,072,855	44,531,168		55,604,023	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
							2
							3
450,910				15,420,764		15,420,764	4
							5
591,699				8,597,602		8,597,602	6
							7
							8
				-1,112,415		-1,112,415	9
							10
							11
							12
							13
							14
1,707,924			11,072,855	44,531,168		55,604,023	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
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19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
						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**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
				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**	**0**	

Schedule Page: 328 Line No.: 1 Column: a

Direct assigned facility charges are billed directly by the Empire District Electric Company.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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 Tarirff (d)	Total Revenue (e)
1	The Empire District Electric Company		2nd Rev Vol No 2	1,162,968	1,162,968
2	The Empire District Electric Company	NF	2nd Rev Vol No 2	150,100	150,100
3	The Empire District Electric Company	FNS	2nd Rev Vol No 2	2,225,993	2,225,993
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			3,539,061	3,539,061

Schedule Page: 331 Line No.: 1 Column: b

SFP & LFP - The Empire District Electric Company does not have a way to separate the revenue for Short-Term Firm Point to Point and Long-Term Firm Point to Point.

Schedule Page: 331 Line No.: 1 Column: e

Sch 7 - Long-Term Firm/Short-Term Firm Point to Point Trans

Schedule Page: 331 Line No.: 2 Column: e

Sch 8 - Non-Firm Point to Point Trans

Schedule Page: 331 Line No.: 3 Column: e

Sch 9 - Transmission Services

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Received Power From:							
2								
3	City Utilities	OS					132,000	132,000
4	Entergy	LFP						
5	MISO	LFP	705,962	705,962	3,645,055	59,686		3,704,741
6	Associated Electric	LFP			107,229			107,229
7								
8								
9	Southwest Power Pool	FNS	5,576,268	5,576,268				
10	EDE						15,409,946	15,409,946
11								
12								
13								
14								
15								
16								
	TOTAL		6,282,230	6,282,230	3,752,284	59,686	15,541,946	19,353,916

Schedule Page: 332 Line No.: 9 Column: a

The Empire District Electric Company is a member of the SPP-RTO, making SPP the provider of the transmission service. Empire's load utilized the "received" MWh's. Empire's load includes the City of Monett, Mt Vernon, Lockwood and Chetopa.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	250,531
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	320,248
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	60,304
6	Chamber of Commerce Dues	19,944
7	Line of Credit Fees	
8	Conflict Resolution Hotline	
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	651,027

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			3,851,726		3,851,726
2	Steam Production Plant	22,307,835				22,307,835
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	207,960				207,960
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	12,710,026				12,710,026
7	Transmission Plant	8,050,866				8,050,866
8	Distribution Plant	31,516,331				31,516,331
9	Regional Transmission and Market Operation					
10	General Plant	3,000,008				3,000,008
11	Common Plant-Electric					
12	TOTAL	77,793,026		3,851,726		81,644,752

B. Basis for Amortization Charges

See Footnote in Section A, Line 12, Column (f)

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	302	1,080	30.49		3.28		3.33
13	303	41,663	10.92		9.16		5.31
14	INTANGIBLE SUBTOTAL	42,743					
15							
16	311	163,832	83.33		1.20		66.41
17	312	833,746	52.08		1.92		40.19
18	312.7	18,416	52.08		1.92		24.32
19	314	193,562	61.35		1.63		50.09
20	315	47,180	54.05		1.85		40.40
21	316	9,901	51.02		1.96		31.43
22	STEAM PROD	1,266,637					
23							
24	331	877	60.61		1.65		37.24
25	332	3,678	61.35		1.63		33.49
26	333	6,100	68.49		1.46		56.39
27	334	2,283	68.97		1.45		49.43
28	335	472	41.49		2.41		27.32
29	HYDRO PROD	13,410					
30							
31	341	23,986	35.21		2.84		28.89
32	342	1,122	35.21		2.84		18.04
33	343	197,211	35.21		2.84		29.20
34	344	39,847	35.21		2.84		28.10
35	345	30,000	35.21		2.84		28.88
36	346	5,498	35.34		2.83		27.71
37	STATELINE CC	297,664					
38							
39	341	26,506	55.25		1.81		32.15
40	342	4,535	26.46		3.78		7.73
41	343	146,460	51.81		1.93		31.62
42	344	16,718	54.95		1.82		26.41
43	345	9,269	28.25		3.54		15.98
44	346	3,722	25.38		3.94		8.63
45	OTHER PROD	207,210					
46							
47							
48							
49							
50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/13/2019	End of 2018/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	352	3,172	49.75		2.01		29.18
13	353	142,632	45.87		2.18		33.61
14	354	1,798	54.64		1.83		29.21
15	355	96,962	31.35		3.19		21.65
16	356	82,825	47.85		2.09		34.07
17	TRANS SUBTOTAL	327,389					
18							
19	361	24,527	50.51		1.98		39.85
20	362	115,727	40.98		2.44		28.84
21	364	319,120	41.15		2.43		20.89
22	365	359,299	47.62		2.10		24.61
23	366	51,313	33.67		2.97		19.27
24	367	65,525	27.70		3.61		12.48
25	368	120,444	39.84		2.51		27.97
26	369	126,462	33.00		3.03		15.90
27	370	21,575	38.76		2.58		-61.88
28	371	16,239	19.42		5.15		10.91
29	373	27,792	42.37		2.36		31.58
30	DIST SUBTOTAL	1,248,023					
31							
32	390	11,156	35.21		2.84		14.00
33	391	5,404	20.16		4.96		10.91
34	391C	14,462	9.91		10.09		1.79
35	392	13,074	14.29		7.00		6.13
36	393	784	31.85		3.14		16.21
37	394	7,882	23.04		4.34		9.10
38	395	1,827	38.76		2.58		19.79
39	396	15,513	15.95		6.27		8.36
40	397	13,161	24.75		4.04		9.71
41	398	235	22.62		4.42		6.47
42	GENERAL SUBTOTAL	83,498					
43							
44	TOTAL	3,486,574					
45							
46							
47							
48							
49							
50							

Schedule Page: 336 Line No.: 12 Column: b

Item 4, Pag 2 (Lines 1 & 2) of the Company's GFR and the Inputs Page 1 (Lines 60 & 63) of the Company's TFR will be adjusted to reflect Generation Plant, Transmission Plant and General Plant Depreciation Expense based only on the Ferc Depreciation Rates.

Recalculation using Ferc rates only:

Functional Classification	**Depreciation Expense Using Ferc Rates**
Steam Production Plant	14,007,288
Hydraulic Prod Plant-Conventional	162,774
Other Production Plant	14,175,926
Transmission Plant	8,712,110
Distribution Plant	24,806,211
General Plant	3,013,025
Total	**64,877,334**

Reconciliation to Ferc Pg 115:

77,800,592	Ferc Pg 115, Line 6
(7,566)	Non-Regulated - Non-Utility
77,793,026	**Ferc Pg 336, Line 12, Col (b)**

Schedule Page: 336 Line No.: 12 Column: f

Section B - Basis for Amortization Charges:

Description	**Acct**	**Vintage**	2018 **Beg Plant**	2018 **Activity**	2018 **End Plant**	**Life**	**Rate**
Organizational Costs	301	1904	29,940		29,940	N/A	
FERC Operating License	302	1992	1,079,798		1,079,798	30	3.33%
Stockton Dam 161kV Circuit	303	1972	122,178		122,178	30	3.33%
Software, Customer Info Sys	303	1995	140,879		140,879	5	20.00%
Software, Cent/Vis Smalltalk	303	1999	488,433		488,433	10	10.00%
Software, Planning & Prot	303	1999	189,707		189,707	5	20.00%
Software, Iatan Plant Drwg	303	2000	16,895		16,895	5	20.00%
Software, DCS Upgrade	303	2002	812,196		812,196	10	10.00%
Software, Iatan Empac Upgrade	303	2002	29,422		29,422	5	20.00%
KAMO Sub 262/Chesapeake 446	303	2003	731,143		731,143	30	3.33%
Software, GIS AM/FM	303	2003	379,500		379,500	8	12.50%
Software, Fin Forecasting	303	2005	119,517		119,517	5	20.00%
Software, Iatan Empac Insite	303	2006	12,795		12,795	5	20.00%
Software, SPP	303	2006	257,839		257,839	5	20.00%
City Utilities Sub 170	303	2007	1,171,053		1,171,053	30	3.33%
Network Upgrades SW Pwr Admin	303	2007	219,151		219,151	30	3.33%
Software, Checkworks	303	2007	14,988		14,988	5	20.00%
Software, Iatan CMMS	303	2007	93,435		93,435	5	20.00%
Software, Iatan Empac Curator	303	2007	4,809		4,809	5	20.00%
Software, Iatan Equip Condition	303	2007	3,953		3,953	5	20.00%
Software, Iatan Pasta	303	2008	21,887		21,887	5	20.00%
Software, Critical Piping	303	2009	19,030		19,030	5	20.00%
Entergy Transmission Line	303	2010	658,212		658,212	30	3.33%
KAMO Riverside Sub	303	2010	3,989,045		3,989,045	30	3.33%
Plum Point Switchyard	303	2010	881,371		881,371	30	3.33%
Software, Enoserv Relay Testing	303	2010	53,166		53,166	10	10.00%
Software, Iatan Equip Monitor	303	2010	21,587		21,587	5	20.00%
Software, Plum Point Operating	303	2010	103,370		103,370	7	14.29%
Software, Power Tax	303	2010	328,722		328,722	7	14.29%
Transmission Upgrades PPA	303	2010	1,526,913		1,526,913	30	3.33%
Software, Day Ahead Market	303	2011	1,221,177		1,221,177	10	10.00%
Software, PCI	303	2011	2,071,988		2,071,988	10	10.00%
Software, EMS	303	2012	247,368		247,368	10	10.00%
Software, Intergraph GIS	303	2012	153,663		153,663	10	10.00%

Software, Intergraph OMS	303	2012	183,625		183,625	10	10.00%
Software, Maximo Proj Overhaul	303	2012	6,494,350	3,117	6,497,467	10	10.00%
Software, Peoplesoft Acctg	303	2012	5,367,433		5,367,433	10	10.00%
Software, Peoplesoft HCM	303	2012	2,445,874		2,445,874	10	10.00%
Software, Power Plant	303	2012	2,620,825		2,620,825	10	10.00%
Software, Share Point	303	2012	493,225		493,225	10	10.00%
Software, SLCC DCS Ctrl Sys	303	2012	1,336,490		1,336,490	7	14.29%
Software, EDI	303	2013	151,584		151,584	10	10.00%
Software, Iatan Cyber Security	303	2013	146,193		146,193	5	20.00%
Software, Teammate Audit Mgmt	303	2013	59,043		59,043	10	10.00%
Software, Asbury DCS Upgrade '14	303	2014	32,785		32,785	7	14.29%
Software, Monarch Remote User	303	2014	42,638		42,638	10	10.00%
Software, TALEO	303	2014	34,874		34,874	10	10.00%
Software, EMS, OSI/Monarch	303	2015	379,210		379,210	10	10.00%
Software, Assyst Service Desk	303	2016	275,709		275,709	5	20.00%
Software, Dell KASE 1000-Serv Dsk	303	2016	83,911		83,911	5	20.00%
Software, Peoplesoft 9.2 Upgrd	303	2016	537,048		537,048	10	10.00%
Software, Peoplesoft HCM Upgrd	303	2016	552,121		552,121	10	10.00%
Software, Pwr Plt 2015.2 Upgrd	303	2016	525,675		525,675	10	10.00%
Software, Pwr Tax 2015.2 Upgrd	303	2016	273,753		273,753	10	10.00%
Software, Proofpt/Firewall Sec	303	2016	160,878		160,878	5	20.00%
Software, Ceridian Payroll	303	2017	206,771	(1,313)	205,458	10	10.00%
Software, Cust Watch Upgrd 3.3	303	2017	965,599		965,599	5	20.00%
Software, CW Upgrd Net Metering	303	2017	147,235	3	147,238	5	20.00%
Software, HMI Upgrd Riv 10&11	303	2017	14,537	(1,317)	13,220	10	10.00%
Software, Maximo Mobile	303	2017	116,143	2,005	118,148	10	10.00%
Software, Microsoft Enter Lic	303	2017	145,267	8,368	153,635	3	33.33%
Software, OSI Security Profiler	303	2017	15,748	9	15,757	5	20.00%
Software, PCI 2017 Upgrades	303	2017	192,348		192,348	5	20.00%
Software, Plum Pt Turbine Contr	303	2017	87,095	(69,189)	17,906	7	14.29%
Software, SO/PD II Test Battery	303	2017	66,279		66,279	10	10.00%
Software, Dewpoint Monitoring PP	303	2018		32,692	32,692	10	10.00%
Software, Adapt 2	303	2018		1,230,421	1,230,421	10	10.00%
Software, OMS Upgrade	303	2018		344,769	344,769	10	10.00%
Software, Encompass ProMod	303	2018		108,439	108,439	10	10.00%
Software, Hyperion Financial	303	2018		183,250	183,250	3	33.33%
Software, Adobe Consolidation	303	2018		15,431	15,431	10	10.00%
Software, Active Dir Convergence	303	2018		88,083	88,083	3	33.33%
Software, Forecast Model Upgrade	303	2018		52,308	52,308	5	20.00%
Software, Cont Sys Upgrade SLC	303	2018		215,460	215,460	10	10.00%
Totals			**41,369,396**	**2,212,536**	**43,581,932**		

Schedule Page: 336.1 Line No.: 44 Column: a

BLENDED COMPOSITE/FINANCIAL BOOK:

LINE	ACCT NUMBER	DEPREC PLT BASE (1000'S)	BLEND RATE AVG LIFE	WEIGHTED AVG BLENDED *RATE%	AVG REM LIFE
12	302	1,080	30.49	3.28%	3.33
13	303	41,663	10.92	9.16%	5.31
14	INTANGIBLE	42,743			
15					
16	311	82,604	42.02	2.38%	33.49
17	312	531,825	33.22	3.01%	25.64
18	312.7	5,542	15.67	6.38%	7.32
19	314	119,059	37.74	2.65%	30.81
20	315	37,949	43.48	2.30%	32.50
21	316	7,857	40.49	2.47%	24.94
22	STEAM PROD	784,836			
23					
24	331	822	56.82	1.76%	34.91
25	332	3,426	57.14	1.75%	31.19
26	333	3,889	43.67	2.29%	35.95
27	334	1,478	44.64	2.24%	31.99
28	335	632	55.56	1.80%	36.58
29	HYDRO PROD	10,247			
30					
31	341	28,743	42.19	2.37%	34.61
32	342	1,436	45.05	2.22%	

33	343	259,296	46.30	2.16%	38.40
34	344	51,674	45.66	2.19%	36.44
35	345	35,207	41.32	2.42%	33.89
36	346	6,403	41.15	2.43%	32.27
37	OTHER PROD CC	382,759			
38					
39	341	12,692	26.46	3.78%	15.39
40	342	6,444	37.59	2.66%	10.99
41	343	108,301	38.31	2.61%	23.38
42	344	12,893	42.37	2.36%	20.36
43	345	9,974	30.40	3.29%	17.19
44	346	4,040	27.55	3.63%	9.37
45	OTHER PROD	154,344			
46					
47	352	3,220	50.51	1.98%	29.62
48	353	166,277	53.48	1.87%	39.18
49	354	1,971	59.88	1.67%	32.01
50	355	94,302	30.49	3.28%	21.06
51	356	94,593	54.64	1.83%	38.91
52	TRANS	360,363			
53					
54	361	26,394	54.35	1.84%	42.88
55	362	130,729	46.30	2.16%	32.57
56	364	211,875	27.32	3.66%	13.87
57	365	213,144	28.25	3.54%	14.60
58	366	45,223	29.67	3.37%	16.98
59	367	66,820	28.25	3.54%	12.73
60	368	123,393	40.82	2.45%	28.65
61	369	86,108	22.47	4.45%	10.83
62	370	24,630	44.25	2.26%	(70.64)
63	371	17,718	21.19	4.72%	11.91
64	373	20,058	30.58	3.27%	22.79
65	DIST	966,092			
66					
67	390	11,866	37.45	2.67%	14.89
68	391	6,307	23.53	4.25%	12.74
69	391C	14,725	10.09	9.91%	1.82
70	392	14,458	15.80	6.33%	6.78
71	393	867	35.21	2.84%	17.92
72	394	7,067	20.66	4.84%	8.16
73	395	1,998	42.37	2.36%	21.63
74	396	18,146	18.66	5.36%	9.78
75	397	11,895	22.37	4.47%	8.77
76	398	279	26.88	3.72%	7.69
77	GENERAL	87,608			
78					
79	TOTAL	2,788,992			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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	Annual Charges (18 CFR, Part 382)	139,111		139,111	
3					
4	Missouri Public Service Commission:				
5	Assessment of Expenses	906,086		906,086	
6					
7	State Corporation Commission of Kansas:				
8	Assessment of Expenses- Various Dockets	131,053		131,053	
9					
10	Oklahoma Corporation Commission:				
11	Annual Assessment Fee	13,985		13,985	
12					
13	Arkansas Public Service Commission:				
14	Assessment Fee				
15					
16	Amortization:				
17	2016 MO Rate Case		18,744	18,744	
18	2014 MO Rate Case				
19	2010 AR Rate Case				
20	2013 AR Rate Case				
21					
22					
23					
24					
25	See Footnote				
26					
27					
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31					
32					
33					
34					
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36					
37	FERC Generation Formula Rate Case Expense				
38					
39					
40					
41	FERC Transmission Formula Rate Case Expense				
42					
43	Lines 41-44 Reserved for TFR Rate Case Expense				
44					
45					
46	TOTAL	1,190,235	18,744	1,208,979	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
							2
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Schedule Page: 350   Line No.: 25   Column: a

We do not show regulatory commission deferred in 182.3. Rate case deferred is in the 186 accounts.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

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

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1		
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	11,324,503		
4	Transmission	896,202		
5	Regional Market			
6	Distribution	5,048,824		
7	Customer Accounts	4,980,174		
8	Customer Service and Informational	1,604,539		
9	Sales	109,717		
10	Administrative and General	12,499,094		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	36,463,053		
12	Maintenance			
13	Production	7,035,253		
14	Transmission	1,432,870		
15	Regional Market			
16	Distribution	4,683,166		
17	Administrative and General	181,879		
18	TOTAL Maintenance (Total of lines 13 thru 17)	13,333,168		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	18,359,756		
21	Transmission (Enter Total of lines 4 and 14)	2,329,072		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	9,731,990		
24	Customer Accounts (Transcribe from line 7)	4,980,174		
25	Customer Service and Informational (Transcribe from line 8)	1,604,539		
26	Sales (Transcribe from line 9)	109,717		
27	Administrative and General (Enter Total of lines 10 and 17)	12,680,973		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	49,796,221	567,505	50,363,726
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance	395,456	11,581	407,037
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	50,191,677	579,086	50,770,763
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	7,596,966	6,784,447	14,381,413
69	Gas Plant			
70	Other (provide details in footnote):	45,458		45,458
71	TOTAL Construction (Total of lines 68 thru 70)	7,642,424	6,784,447	14,426,871
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,487,758	1,328,979	2,816,737
74	Gas Plant			
75	Other (provide details in footnote):	6,067		6,067
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,493,825	1,328,979	2,822,804
77	Other Accounts (Specify, provide details in footnote):			
78				
79	Clearings:	8,692,512	-8,692,512	
80	Other Inc & Deductions	72,671		72,671
81	Non-Utility O&M	711,703		711,703
82	Non-Utility Construction	281,260		281,260
83	Non-Utilitiy Plant Removal	41,616		41,616
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	9,799,762	-8,692,512	1,107,250
96	TOTAL SALARIES AND WAGES	69,127,688		69,127,688

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Water Dept

Schedule Page: 354 Line No.: 70 Column: b

Water Dept

Schedule Page: 354 Line No.: 75 Column: b

Water Dept

Name of Respondent The Empire District Electric Company	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report *(Mo, Da, Yr)* 05/13/2019	Year/Period of Report End of 2018/Q4

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	10,963,131	17,023,753	18,334,197	27,641,993
3	Net Sales (Account 447)	(11,907,325)	(21,369,488)	(25,074,182)	(31,402,608)
4	Transmission Rights	(9,193,414)	(13,372,925)	(15,353,657)	(19,830,818)
5	Ancillary Services	462,431	888,725	1,265,672	1,879,203
6	Other Items (list separately)	(116,518)	(1,023,214)	(760,212)	(1,076,868)
7					
8	MISO	(370,783)	(516,620)	(708,706)	(1,112,415)
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45					
46	TOTAL	(10,162,478)	(18,369,769)	(22,296,888)	(23,901,513)

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch						
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)						

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

N/A - The Empire District Electric Company is a member of the SPP/RTO. This information is filed by the RTO. The Company no longer provides any transmission service under our tariff. It is provided by the SPP regional tariff.

Name of Respondent The Empire District Electric Company	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report (Mo, Da, Yr) 05/13/2019	Year/Period of Report End of 2018/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	1,211	17	700	1,151	60				
2	February	1,036	5	800	982	54				
3	March	837	13	800	786	51				
4	Total for Quarter 1				2,919	165				
5	April	801	4	800	752	49				
6	May	931	30	1800	873	58				
7	June	1,108	28	1700	1,040	68				
8	Total for Quarter 2				2,665	175				
9	July	1,106	11	1600	1,036	70				
10	August	1,043	6	1600	977	66				
11	September	1,018	19	1700	954	64				
12	Total for Quarter 3				2,967	200				
13	October	858	3	1700	803	55				
14	November	969	14	800	915	54				
15	December	941	10	800	888	53				
16	Total for Quarter 4				2,606	162				
17	Total Year to Date/Year				11,157	702				

Schedule Page: 400 Line No.: 1 Column: g

Column g, h & i – The Empire District Electric Company is a part of the SPP tariff. We are unable to provide an accounting of the loads on our transmission lines due to those transactions.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/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 (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (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									

Schedule Page: 980 Line No.: 1 Column: b

N/A - The Empire District Electric Company is a member of the SPP-RTO. This information is filed by the RTO.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	4,891,523
3	Steam	5,067,589			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	345,155
5	Hydro-Conventional	49,345			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	1,521,843
7	Other				
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	5,116,934	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	12,073
10	Purchases	1,707,924	27	Total Energy Losses	54,264
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	6,824,858
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
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)	6,824,858			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	769,642	108,144	1,211	17	700
30	February	532,907	222,438	1,036	5	800
31	March	584,542	199,634	837	13	800
32	April	417,234	-19,019	801	4	800
33	May	548,673	171,539	931	30	1800
34	June	624,143	121,582	1,108	28	1700
35	July	629,199	274,489	1,106	11	1600
36	August	607,708	44,609	1,043	6	1600
37	September	529,566	127,862	1,018	19	1700
38	October	542,781	142,432	858	3	1700
39	November	496,179	69,663	969	14	800
40	December	542,284	58,470	941	10	800
41	TOTAL	6,824,858	1,521,843			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Riverton (7 & 8)* (b)	Plant Name: *Riverton (10-11-12)* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam	Combustion Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Semi-Outdoor	Conventional
3	Year Originally Constructed	1906	1964
4	Year Last Unit was Installed	1954	2016
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	300.15
6	Net Peak Demand on Plant - MW (60 minutes)	0	286
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	261
9	When Not Limited by Condenser Water	0	261
10	When Limited by Condenser Water	0	261
11	Average Number of Employees	0	24
12	Net Generation, Exclusive of Plant Use - KWh	0	1293984000
13	Cost of Plant: Land and Land Rights	0	253184
14	Structures and Improvements	171409	26330329
15	Equipment Costs	75126	215044228
16	Asset Retirement Costs	0	0
17	Total Cost	246535	241627741
18	Cost per KW of Installed Capacity (line 17/5) Including	0	805.0233
19	Production Expenses: Oper, Supv, & Engr	2167	459912
20	Fuel	0	28519848
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	-333	1457212
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	-278	0
26	Misc Steam (or Nuclear) Power Expenses	2078	389788
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	435900
30	Maintenance of Structures	0	273339
31	Maintenance of Boiler (or reactor) Plant	13346	0
32	Maintenance of Electric Plant	210702	4202469
33	Maintenance of Misc Steam (or Nuclear) Plant	0	150870
34	Total Production Expenses	227682	35889338
35	Expenses per Net KWh	0.0000	0.0277

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)				Gas	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)				MCF	BBL	
38	Quantity (Units) of Fuel Burned	0	0	0	9237718	14	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	1037	139743	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	3.091	46.322	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	3.092	46.322	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	2.982	7.891	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.022	0.002	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	7403.575	192.296	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: *State Line* (b)			Plant Name: *SL Combined Cycle* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Combustion Turbine			Combined Cycle		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Combined Cycle		
3	Year Originally Constructed	1995			2001		
4	Year Last Unit was Installed	1995			2001		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	123.30			340.47		
6	Net Peak Demand on Plant - MW (60 minutes)	103			330		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	96			295		
9	When Not Limited by Condenser Water	0			295		
10	When Limited by Condenser Water	0			295		
11	Average Number of Employees	0			29		
12	Net Generation, Exclusive of Plant Use - KWh	23177000			1533111000		
13	Cost of Plant: Land and Land Rights	11897			838836		
14	Structures and Improvements	1106262			10942777		
15	Equipment Costs	41562084			151637705		
16	Asset Retirement Costs	0			0		
17	Total Cost	42680243			163419318		
18	Cost per KW of Installed Capacity (line 17/5) Including	346.1496			479.9815		
19	Production Expenses: Oper, Supv, & Engr	6940			324649		
20	Fuel	929214			31534475		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	31033			2025207		
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	11075			510462		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	15882			303550		
30	Maintenance of Structures	8614			148942		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	74726			5888784		
33	Maintenance of Misc Steam (or Nuclear) Plant	197			297081		
34	Total Production Expenses	1077681			41033150		
35	Expenses per Net KWh	0.0465			0.0268		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Oil		Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF	BBL		MCF		
38	Quantity (Units) of Fuel Burned	282667	501	0	10773048	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1029	133506	0	1037	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.122	87.572	0.000	2.931	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3.126	87.572	0.000	2.932	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.038	15.618	0.000	2.828	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.038	0.195	0.000	0.021	0.000	0.000
44	Average BTU per KWh Net Generation	12671.591	12487.099	0.000	7285.354	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/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: *Asbury* (d)			Plant Name: *Energy Center* (e)			Plant Name: *Iatan (1&2)* (f)			Line No.
Steam			Combustion Turbine			Steam			1
Semi-Outdoor			Conventional			Semi-Outdoor			2
1970			1978			1980			3
1970			2003			2010			4
212.80			379.00			210.47			5
199			205			187			6
0			0			0			7
198			257			190			8
198			0			190			9
198			0			190			10
39			14			27			11
841220000			117952000			908239000			12
1349995			163097			128856			13
21553967			3452115			40621687			14
264374488			93986773			355234588			15
0			0			0			16
287278450			97601985			395985131			17
1349.9927			257.5250			1881.4327			18
1499567			228590			315900			19
25757375			6929191			17006023			20
0			0			0			21
448860			497501			1361765			22
0			0			0			23
0			0			0			24
1163672			0			359644			25
1366090			167947			953525			26
0			0			44438			27
0			0			0			28
600621			97722			392350			29
428125			0			879234			30
2729854			0			2098519			31
415244			2589656			1260889			32
2228211			298531			55631			33
36637619			10809138			24727918			34
0.0436			0.0916			0.0272			35
Coal	Oil	Tires	Gas	Oil		Coal	Oil		36
Tons	BBL	Tons	MCF	BBL		Tons	BBL		37
519159	8157	300	1350024	28539	0	501144	6158	0	38
8641	139399	14000	1036	132295	0	8594	136978	0	39
36.779	96.199	38.000	2.824	110.475	0.000	26.647	82.017	0.000	40
40.396	96.199	38.000	2.826	110.475	0.000	28.100	68.499	0.000	41
2.337	16.431	1.357	2.726	19.883	0.000	1.635	11.907	0.000	42
0.025	0.183	0.015	0.035	0.301	0.000	0.016	0.115	0.000	43
10730.479	11128.549	10986.984	13018.587	15141.278	0.000	9522.270	9699.620	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/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: *SLCC Tolling* (d)			Plant Name: *Plum Point* (e)			Plant Name: (f)			Line No.
Combined Cycle			Steam						1
Combined Cycle			Semi-Outdoor						2
									3
			2010						4
0.00			55.50			0.00			5
0			50			0			6
0			0			0			7
0			50			0			8
0			50			0			9
0			50			0			10
0			6			0			11
0			349906000			0			12
0			956529			0			13
0			20567779			0			14
0			84661452			0			15
0			0			0			16
0			106185760			0			17
0			1913.2569			0			18
0			296300			0			19
0			7300102			0			20
0			0			0			21
0			294946			0			22
0			0			0			23
0			0			0			24
0			149271			0			25
0			486116			0			26
0			0			0			27
0			0			0			28
0			222775			0			29
0			75674			0			30
0			472962			0			31
0			162454			0			32
0			138722			0			33
0			9599322			0			34
0.0000			0.0274			0.0000			35
			Coal	Oil					36
			Tons	BBL					37
0	0	0	190745	1043	0	0	0	0	38
0	0	0	8780	139030	0	0	0	0	39
0.000	0.000	0.000	35.834	189.146	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	37.485	143.835	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	2.135	24.632	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.020	0.239	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	9589.713	9700.746	0.000	0.000	0.000	0.000	44

FOOTNOTE DATA

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

Unit 7 was retired on June 30, 2014. Unit 8 & 9 was retired on June 30, 2015.

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

Riverton 10 & 11 are the only combustion turbines at Riverton. Riverton 12 is combined cycle as of May 2016.

Schedule Page: 402 Line No.: 5 Column: c

MW rating is at 85% power factor.

Schedule Page: 403 Line No.: 5 Column: d

MW rating is at 95% power factor. Unit 2 was retired on December 31, 2013.

Schedule Page: 403 Line No.: 5 Column: e

MW rating is at 90% and 85% power factor.

Schedule Page: 403 Line No.: 5 Column: f

Represents 12% of jointly owned plant. Unit 1 generator is rated at 825 MVA with a 91.5% power factor giving it a nameplate of 754.875 MW (90.585 MW Empire's share). Unit 2 generator is rated at 1,110 MVA with a 90% power factor giving it a nameplate of 999 MW (119.88 MW Empire's share).

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

The Combined Cycle Unit at the State Line Power Plant has generating capacity of 491 megawatts. The respondent is entitled to 60%, or 295 megawatts of the unit's available capacity. The Combined Cycle Unit consists of the combination of two combustion turbines (including the Respondent's former State Line Unit No. 2), two heat recovery steam generators, a steam turbine and auxiliary equipment. In June 2001, the Respondent sold a 40% interest to Westar Energy, Inc. (WGI), a subsidiary of Western Resources, Inc. WGI is entitled to 40% of the unit's available capacity (196Mw) and is obligated for that percentage of the operating expenditures for the unit.

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

SLCC Tolling operating expenditures are not kept separate from SL Combined Cycle.

Schedule Page: 402.1 Line No.: 5 Column: b

MW rating is at 90% power factor.

Schedule Page: 402.1 Line No.: 5 Column: c

MW rating is at 90% power factor.

Schedule Page: 402.1 Line No.: 8 Column: c

The number reported is only Empire District Electric's share of net continuous plant capacity.

Schedule Page: 402.1 Line No.: 9 Column: b

Not Applicable

Schedule Page: 402.1 Line No.: 10 Column: b

Not Applicable

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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. 2221 Plant Name: Ozark Beach (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	
2	Plant Construction type (Conventional or Outdoor)	Conventional	
3	Year Originally Constructed	1913	
4	Year Last Unit was Installed	1930	
5	Total installed cap (Gen name plate Rating in MW)	16.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	19	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	20	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	5	0
12	Net Generation, Exclusive of Plant Use - Kwh	49,345,000	0
13	Cost of Plant		
14	Land and Land Rights	266,488	0
15	Structures and Improvements	842,031	0
16	Reservoirs, Dams, and Waterways	3,418,678	0
17	Equipment Costs	6,468,065	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	10,995,262	0
21	Cost per KW of Installed Capacity (line 20 / 5)	687.2039	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	47,833	0
24	Water for Power	0	0
25	Hydraulic Expenses	41,213	0
26	Electric Expenses	50,402	0
27	Misc Hydraulic Power Generation Expenses	306,364	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	39,817	0
30	Maintenance of Structures	45,404	0
31	Maintenance of Reservoirs, Dams, and Waterways	224,454	0
32	Maintenance of Electric Plant	40,902	0
33	Maintenance of Misc Hydraulic Plant	82,963	0
34	Total Production Expenses (total 23 thru 33)	879,352	0
35	Expenses per net KWh	0.0178	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/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

Schedule Page: 406 Line No.: 5 Column: b

MW rating is at 80% power factor.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

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. 0 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 Demaind 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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/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. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1						
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46						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/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 Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
						2
						3
						4
						5
						6
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						45
						46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	This detail is not		161,000.00	161,000.00	WOOD H	331.70	7.65	1
2	currently available on							
3	Respondent's tracking		161,000.00	161,000.00	STEEL POLE	7.40	1.94	1
4	system.		161,000.00	161,000.00	STEEL	26.49		1
5			161,000.00	161,000.00	STEEL H	20.04		
6			161,000.00	161,000.00	WOOD POLE	19.48		1
7								
8								
9			69,000.00	69,000.00	WOOD H	35.70		1
10			69,000.00	69,000.00	WOOD H		5.24	1
11			69,000.00	69,000.00	WOOD POLE	667.64		1
12			69,000.00	69,000.00	WOOD POLE		10.80	1
13			69,000.00	69,000.00	STEEL POLE	37.28		1
14			69,000.00	69,000.00	STEEL	8.78		1
15			69,000.00	69,000.00	STEEL		28.56	1
16								
17								
18			34,500.00	34,500.00	WOOD H	0.70		1
19			34,500.00	34,500.00	WOOD POLE	52.88		1
20			34,500.00	34,500.00	WOOD POLE		2.86	1
21			34,500.00	34,500.00	STEEL POLE	27.97		1
22			34,500.00	34,500.00	STEEL POLE		7.43	1
23								
24								
25			345,000.00	345,000.00	WOOD H	21.90		1
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	1,257.96	64.48	17

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/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	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
795.000 ACSR								1
565.000 ACSR								2
336.400 ACSR								3
253.000 HDB								4
656.000 ACSR								5
795.000 ACSR	8,954,865	93,602,308	102,557,173	5,667	971,149		976,816	6
								7
								8
Various	2,333,444	96,801,994	99,135,438	33,278	1,861,805		1,895,083	9
								10
								11
								12
								13
								14
								15
								16
								17
Various	42,276	3,401,346	3,443,622	6,767	47,063		53,830	18
								19
								20
								21
								22
								23
								24
Various	593,858	1,680,033	2,273,891		45,441		45,441	25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	11,924,443	195,485,681	207,410,124	45,712	2,925,458		2,971,170	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Sub 170 Nichols St	S Lynn Ave (Sub 359)		Various-WP&SP	12.64	1	1
2	Sub 109	Sub 109 Exits	0.25	SP	37.40	4	4
3							
4							
5							
6							
7							
8							
9							
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39							
40							
41							
42							
43							
44	TOTAL		0.25		50.04	5	5

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/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)	
Various	Various	Various	69		3,716,499	5,045,795		8,762,294	1
556	Various	Various	69		426,526	644,934		1,071,460	2
									3
									4
									5
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									43
					4,143,025	5,690,729		9,833,754	44

Schedule Page: 424 Line No.: 1 Column: h

556 & 558

Schedule Page: 424 Line No.: 1 Column: i

ACSR & AAC

Schedule Page: 424 Line No.: 1 Column: j

6.61H & 9.91V

Schedule Page: 424 Line No.: 2 Column: i

ACSR & AAC

Schedule Page: 424 Line No.: 2 Column: j

7.13H/6.60V/10.6V

Name of Respondent The Empire District Electric Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/13/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	56 Neosho-West MO	Dist Unattended	69.00	12.47	
2	59 Joplin-26th St MO	Dist Unattended	69.00	12.47	
3	66 Scammon-South KS	Dist Unattended	69.00	12.47	
4	73 Bolivar-Burns MO	Trans Unattended	161.00	69.00	
5	73 Bolivar-Burns MO	Trans Unattended			12.00
6	105 Webb City-Tom St MO	Dist Unattended	69.00	12.47	
7	108 Carthage-Northwest MO	Dist Unattended	69.00	12.47	
8	109 Joplin-Atlas Jct MO	Trans Unattended	161.00	69.00	
9	109 Joplin-Atlas Jct MO	Trans Unattended	161.00	12.47	
10	109 Joplin-Atlas Jct MO	Trans Unattended			12.00
11	110 Joplin-Oronogo Jct MO	Trans Unattended	161.00	69.00	
12	110 Joplin-Oronogo Jct MO	Trans Unattended	161.00	12.47	
13	110 Joplin-Oronogo Jct MO	Trans Unattended			12.00
14	110 Joplin-Oronogo Jct MO	Trans Unattended	69.00	12.47	
15	121 Ash Grove H T MO	Dist Unattended	69.00	12.47	
16	124 Aurora H T 161 KV MO	Trans Unattended	161.00	69.00	
17	124 Aurora H T 161 KV MO	Trans Unattended	161.00	12.47	
18	124 Aurora H T 161 KV MO	Trans Unattended			12.00
19	131 Diamond H T MO	Trans Unattended	69.00	12.47	
20	145 Joplin-W 7th St MO	Trans Unattended	161.00	69.00	
21	145 Joplin-W 7th St MO	Trans Unattended	69.00	34.50	
22	145 Joplin-W 7th St MO	Trans Unattended	69.00	12.47	
23	145 Joplin-W 7th St MO	Trans Unattended	69.00	12.47	
24	145 Joplin-W 7th St MO	Trans Unattended	69.00	12.47	
25	145 Joplin-W 7th St MO	Trans Unattended	69.00	4.16	
26	145 Joplin -W 7th St MO	Trans Unattended			12.47
27	167 Riverton KS	Plant Attended	161.00	69.00	
28	167 Riverton KS	Plant Attended	161.00	13.20	
29	167 Riverton KS	Plant Attended	69.00	13.20	
30	167 Riverton KS	Plant Attended	69.00	2.40	
31	167 Riverton KS	Plant Attended	13.80	2.40	
32	167 Riverton KS	Plant Attended			13.80
33	184 Neosho-South Jct MO	Trans Unattended	161.00	69.00	
34	184 Neosho-South Jct MO	Trans Unattended	161.00	12.47	
35	184 Neosho-South Jct MO	Trans Unattended	7.20	2.40	
36	184 Neosho-South Jct MO	Trans Unattended			12.47
37	186 Welch-North OK	Dist Unattended	34.50	12.47	
38	205 Wentworth-West	Dist Unattended	69.00	12.47	
39	209 Hermitage-East MO	Dist Unattended	69.00	12.47	
40	217 Fair Play-East MO	Trans Unattended	69.00	12.47	

Name of Respondent The Empire District Electric Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/13/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	217 Fair Play-East MO	Trans Unattended	69.00	34.50	
2	217 Fair Play-East MO	Trans Unattended			7.00
3	221 Billings-Northeast MO	Trans Unattended	69.00	12.47	
4	258 Gateway Drive Substation MO	Dist Unattended	69.00	12.47	
5	271 Baxter Springs-West H T KS	Trans Unattended	69.00	34.50	
6	271 Baxter Springs-West H T KS	Trans Unattended	69.00	12.47	
7	271 Baxter Springs-West H T KS	Trans Unattended	13.80	12.47	
8	278 Galena-NE KS	Dist Unattended	69.00	12.47	
9	282 Columbus-Tenn St KS	Dist Unattended	69.00	12.47	
10	284 Joplin-East 5th St MO	Dist Unattended	69.00	4.16	
11	291 Baxter Springs-12th St KS	Dist Unattended	69.00	12.47	
12	295 Reeds Spring-161 KV MO	Dist Unattended	161.00	12.47	
13	296 Neosho-Rocketdyne 69 Kv MO	Dist Unattended	69.00	12.47	
14	311 Monett City "New" MO	Dist Unattended	69.00	12.47	
15	312 Ozark Dam-Powersite MO	Trans Unattended	161.00	69.00	
16	312 Ozark Dam-Powersite MO	Trans Unattended	161.00	12.47	
17	312 Ozark Dam-Powersite MO	Trans Unattended	161.00	4.60	
18	312 Ozark Dam-Powersite MO	Trans Unattended			12.47
19	315 Solar-69 Kv SW MO	Trans Unattended	69.00	4.16	
20	318 Collins-South MO	Dist Unattended	34.50	12.47	
21	322 Anderson-SW MO	Dist Unattended	69.00	12.47	
22	323 Brighton-East MO	Dist Unattended	69.00	12.47	
23	330 Ozark-Northwest MO	Dist Unattended	69.00	12.47	
24	331 Branson-North MO	Dist Unattended	161.00	12.47	
25	339 Gulf-Jayhawk KS	Dist Unattended	69.00	12.47	
26	341 Joplin-Northwest MO	Dist Unattended	69.00	12.47	
27	342 Buffalo-South MO	Dist Unattended	69.00	12.47	
28	347 Granby-North MO	Dist Unattended	69.00	12.47	
29	348 Mt Vernon-City MO	Dist Unattended	69.00	4.16	
30	349 Asbury MO	Plant Attended	161.00	19.50	
31	349 Asbury MO	Plant Attended	161.00	12.47	
32	349 Asbury MO	Plant Attended	161.00	13.20	
33	349 Asbury MO	Plant Attended	12.47	4.16	
34	352 Monett-North City MO	Dist Unattended	69.00	12.47	
35	355 Aurora-West MO	Dist Unattended	69.00	12.47	
36	359 Republic-East MO	Dist Unattended	69.00	12.47	
37	360 Joplin-Northeast MO	Dist Unattended	69.00	12.47	
38	362 Sarcoxie-Southwest MO	Dist Unattended	69.00	12.47	
39	363 Fairland-West OK	Dist Unattended	69.00	12.47	
40	366 Carl Junction-East MO	Dist Unattended	161.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	367 Bolivar-Southeast MO	Dist Unattended	69.00	12.47	
2	368 Dadeville-East MO	Trans Unattended	161.00	69.00	
3	368 Dadeville-East MO	Trans Unattended			12.00
4	369 Willard MO	Dist Unattended	69.00	12.47	
5	369 Willard MO	Dist Unattended	69.00	12.47	
6	370 Strafford MO	Dist Unattended	69.00	12.47	
7	372 Joplin 2nd & Division MO	Dist Unattended	69.00	12.47	
8	375 Seneca-East MO	Dist Unattended	69.00	12.47	
9	376 Monett-South City MO	Dist Unattended	69.00	12.47	
10	377 Quapaw-Eagle Picher OK	Dist Unattended	69.00	12.47	
11	381 Commerce-North 69/12 Kv OK	Dist Unattended	69.00	12.47	
12	382 LaRussell Energy Center MO	Plant Attended	161.00	13.20	
13	383 Monett 161-69 Kv MO	Trans Unattended	161.00	69.00	
14	383 Monett 161-69 Kv MO	Trans Unattended			12.00
15	387 Hollister-East MO	Dist Unattended	161.00	12.47	
16	389 Joplin-161-69 Kv SW MO	Trans Unattended	161.00	69.00	
17	389 Joplin-161-69 Kv SW MO	Trans Unattended	161.00	12.47	
18	389 Joplin-161-69 Kv SW MO	Trans Unattended			12.00
19	390 Purdy-South MO	Dist Unattended	69.00	12.47	
20	391 Joplin-Southeast MO	Dist Unattended	161.00	12.47	
21	392 Decatur-South AR	Trans Unattended	161.00	69.00	
22	392 Decatur-South AR	Trans Unattended	161.00	12.47	
23	392 Decatur-South AR	Trans Unattended			12.00
24	393 Reinmiller-161-69 Kv MO	Trans Unattended	161.00	69.00	
25	395 Carthage-Southwest MO	Dist Unattended	161.00	12.47	
26	396 Iatan Plant MO	Plant Attended	345.00	22.80	
27	397 Fair Grove-South MO	Trans Unattended	69.00	12.47	
28	398 Neosho-East MO	Dist Unattended	69.00	12.47	
29	403 Jasper-West MO	Dist Unattended	69.00	12.47	
30	404 Hockerville-161-69 Kv OK	Trans Unattended	161.00	69.00	
31	404 Hockerville-161-69 Kv OK	Trans Unattended	161.00	138.00	
32	404 Hockerville-161-69 Kv OK	Trans Unattended			12.47
33	404 Hockerville-161-69 Kv OK	Trans Unattended			12.00
34	406 Riverton-South KS	Dist Unattended	69.00	12.47	
35	409 Buffalo-North MO	Dist Unattended	69.00	12.47	
36	410 Forsyth-North MO	Dist Unattended	69.00	12.47	
37	413 Branson-Southwest MO	Dist Unattended	161.00	12.47	
38	414 Southwest City MO	Dist Unattended	69.00	12.47	
39	415 Blackhawk Jct MO	Trans Unattended	69.00	12.47	
40	416 Monett-East City MO	Dist Unattended	69.00	12.47	

Name of Respondent The Empire District Electric Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/13/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	417 Joplin-Fir Road MO	Dist Unattended	161.00	12.47	
2	418 Stockton-AEC Tie MO	Trans Unattended	161.00	69.00	
3	418 Stockton-AEC Tie MO	Trans Unattended	69.00	12.47	
4	418 Stockton-AEC Tie MO	Trans Unattended			12.00
5	420 Mt Vernon-Southwest City MO	Dist Unattended	69.00	12.47	
6	421 Purcell-Southwest MO	Dist Unattended	161.00	12.47	
7	422 Joplin-24th & Conn MO	Dist Unattended	161.00	12.47	
8	428 Fairland-Southwest OK	Dist Unattended	69.00	12.47	
9	430 Joplin-32nd & Oliver MO	Trans Unattended	161.00	69.00	
10	430 Joplin-32nd & Oliver MO	Dist Unattended	69.00	12.47	
11	430 Joplin-32nd & Oliver MO	Dist Unattended	69.00	12.47	
12	430 Joplin-32nd & Oliver MO	Dist Unattended	69.00	2.40	
13	430 Joplin-32nd & Oliver MO	Dist Unattended	161.00	12.47	
14	430 Joplin-32nd & Oliver MO	Dist Unattended	69.00	7.20	
15	430 Joplin-32nd & Oliver MO	Dist Unattended	69.00	7.20	
16	430 Joplin-32nd & Oliver MO	Dist Unattended	69.00	4.16	
17	430 Joplin-32nd & Oliver MO	Trans Unattended			12.00
18	431 Bolivar-South MO	Dist Unattended	161.00	12.47	
19	432 Oakland-North MO	Dist Unattended	161.00	12.47	
20	433 Gretna MO	Dist Unattended	161.00	12.47	
21	434 Ozark-Southeast MO	Dist Unattended	69.00	12.47	
22	435 Noel Southwest MO	Trans Unattended	161.00	69.00	
23	435 Noel Southwest MO	Trans Unattended			12.47
24	436 Webb City-Cardinal MO	Trans Unattended	69.00	12.47	
25	437 Marionville-North MO	Dist Unattended	69.00	12.47	
26	438 Riverside MO	Dist Unattended	161.00	12.47	
27	439 State Line MO	Plant Attended	161.00	13.80	
28	439 State Line MO	Plant Attended	161.00	18.00	
29	439 State Line MO	Plant Attended	161.00	4.16	
30	443 Noel City MO	Dist Unattended	69.00	12.47	
31	446 Chesapeake MO	Trans Unattended	161.00	69.00	
32	446 Chesapeake MO	Trans Unattended			12.00
33	447 Joplin-32nd & Stephens MO	Dist Unattended	69.00	12.47	
34	451 Republic Hines Street MO	Dist Unattended	69.00	12.47	
35	452 Riverton Rams KS	Trans Attended	161.00	69.00	
36	452 Riverton Rams KS	Trans Attended			12.00
37	452 Riverton Rams KS	Trans Attended			12.00
38	453 Riverton-Turbine KS	Plant Attended	161.00	16.00	
39	453 Riverton-Turbine KS	Plant Attended	161.00	4.16	
40	457 Ozark South MO	Trans Unattended	161.00	69.00	

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	457 Ozark South MO	Trans Unattended			12.47
2	460 Pierce City North MO	Dist Unattended	69.00	12.47	
3	467 Decatur-North AR	Dist Unattended	69.00	12.47	
4	469 Joplin-Silver Creek	Dist Unattended	161.00	12.47	
5	471 Joplin-Kodiak	Dist Unattended	69.00	12.47	
6	477 Joplin-Wildwood Ranch	Dist Unattended	161.00	12.47	
7	602 Bolivar Plant MO	Dist Unattended	69.00	12.47	
8	614 Greenfield	Dist Unattended	69.00	4.16	
9	614 Greenfield	Dist Unattended	69.00	12.47	
10	700 Gravette AR	Dist Unattended	69.00	12.47	
11					
12	109 Subtotal		15342.27	3064.97	263.62
13	29 Substations with Capacity < 10,000		1369.59	301.55	12.00
14	138 Total Substations		16711.86	3366.52	275.62
15					
16					
17					
18	6 Substation	Plant Attended	2280.27	241.65	13.80
19	1 Substations	Trans Attended	161.00	69.00	24.00
20	101 Substations	Dist Unattended	8384.59	1223.27	
21	30 Substations	Trans Unattended	5886.00	1832.60	237.82
22	138 Total		16711.86	3366.52	275.62
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
22	1	1				1
45	2					2
11	1					3
75	1					4
						5
22	1					6
45	2					7
150	1					8
22	1					9
						10
150	1					11
22	1					12
						13
		1				14
11	1					15
150	1					16
22	1					17
						18
11	1					19
150	1					20
		2				21
45	2	1				22
						23
		1				24
		1				25
						26
67	1					27
39	1					28
65	2					29
4	1					30
7	2					31
						32
100	2					33
22	1					34
						35
						36
11	1					37
11	1					38
11	1					39
5	1					40

Name of Respondent The Empire District Electric Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/13/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
12	1					1
						2
11	1					3
45	2					4
9	1	3				5
9	1					6
		1				7
33	2					8
20	2					9
16	2					10
21	2					11
14	1					12
22	1					13
22	1					14
47	1					15
22	1					16
22	1					17
						18
20	1	1				19
11	1					20
11	1					21
11	1					22
45	2					23
45	2	1				24
11	1					25
22	1					26
21	2					27
11	1					28
11	1					29
252	1					30
28	1					31
28	1					32
		1				33
11	1					34
22	1					35
33	2					36
45	2					37
11	1					38
11	1					39
28	2					40

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
21	2					1
75	1					2
						3
21	2					4
		1				5
11	1					6
22	1					7
11	1					8
22	1					9
21	2					10
11	1					11
408	4					12
150	1					13
						14
45	2					15
150	1	1				16
22	1	1				17
						18
22	1					19
45	2					20
75	1					21
22	1					22
						23
150	1					24
22	1					25
87	1					26
11	1					27
22	1					28
11	1					29
75	1					30
112	1					31
						32
						33
11	1					34
11	1					35
22	1					36
67	3					37
22	1					38
45	2					39
33	2					40

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
22	1					1
75	1					2
11	1					3
						4
11	1					5
14	1					6
22	1					7
11	1					8
		2				9
22	1	3				10
		1				11
		1				12
		1				13
		1				14
		1				15
		1				16
						17
22	1					18
22	1					19
22	1					20
45	2					21
75	1					22
						23
22	1					24
21	2					25
22	1					26
133	1					27
378	3					28
19	2					29
22	1					30
75	1					31
						32
45	2					33
22	1					34
100	1					35
						36
						37
200	1					38
12	1					39
100	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
						1
10	1					2
22	1					3
22	1					4
22	1					5
22	1					6
22	1					7
5	1					8
6	1					9
22	1					10
						11
5861	167	28				12
136	56	6				13
5997	223	34				14
						15
						16
						17
1727	23	1				18
100	1					19
1825	153	16				20
2345	46	17				21
5997	223	34				22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/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	Construction Work in Progress	Liberty Utilities Canada	107	1,293,340
3	Debt Issuance Costs	Liberty Utilities Canada	181	450,000
4	Employee Flex Plan	Liberty Utilities Canada	242	234,530
5	Conventions and Seminars	Liberty Utilities Canada	426	283
6	Generation Operations Supervision	Liberty Utilities Canada	500	459
7	Steam Power Expense	Liberty Utilities Canada	506	503
8	Conventions & Seminars	Liberty Utilities Canada	546	662
9	Other Power Expense	Liberty Utilities Canada	549	3,669
10	Generating Equip Maint	Liberty Utilities Canada	553	1,442
11	Transmission Operation & Supervision	Liberty Utilities Canada	560	2,688
12	Distribution, Operation & Supervision	Liberty Utilities Canada	580	2,889
13	Conventions and Seminars	Liberty Utilities Canada	588	593
14	Maint of Overhead Lines	Liberty Utilities Canada	593	1,116
15	Customer Service Expense	Liberty Utilities Canada	901	4,170
16	Billing Expense	Liberty Utilities Canada	903	533
17	Customer Assistance Expense	Liberty Utilities Canada	908	321
18	Administrative & General Salaries	Liberty Utilities Canada	920	2,097,618
19	Administrative & General Other	Liberty Utilities Canada	921	855,621
20	**Non-power Goods or Services Provided for Affiliate**			
21	Executive Legal Fees	Algonquin Pwr & Utilities Corp	922	985
22	Meter & Transformer Exp	Liberty Utilities Canada	922	1,882
23	Substation Maintenance Exp	Liberty Utilities Canada	922	2,860
24	OMS Mapping Exp	Liberty Utilities Canada	922	4,887
25	Insurance Services	Liberty Utilities Canada	922	44
26	Accounting	Liberty Utilities Canada	922	38
27	Financial Forecasting	Liberty Utilities Canada	922	3,024
28	Billing Operations	Liberty Utilities Canada	922	2,791
29	IT Expense	Liberty Utilities Canada	922	407
30	Executive A&G Exp	Liberty Utilities Canada	922	3,005
31	Customer Billing	Liberty Utilities Serv Corp	922	4,933
32	Accounts Payable	Liberty Utilities Serv Corp	922	4,084
33	Rent	Liberty Utilities Serv Corp	922	177,413
34	Line Operations Exp	Liberty Utilities Serv Corp	922	1,831
35	Transportation Exp	Liberty Utilities Serv Corp	922	-727
36	OMS Mapping Exp	Liberty Utilities Serv Corp	922	73
37	Field Safety Exp	Liberty Utilities Serv Corp	922	54,938
38	Electric Procurement	Liberty Utilities Serv Corp	922	2,800
39	Substation & Protection Engineering	Liberty Utilities Serv Corp	922	353
40	System Planning & Transmission	Liberty Utilities Serv Corp	922	1,020
41	Treasury Services	Liberty Utilities Serv Corp	922	1,272
42	Corporate Secretary	Liberty Utilities Serv Corp	922	2,794
1	**Non-power Goods or Services Provided by Affiliated**			
2	A&G Costs to be Billed to Affiliates	Liberty Utilities Canada	922	10,005

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/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)
3	Indirect Allocations	Liberty Utilities Canada	923	8,538,755
4	CWIP	Liberty Utilities Serv Corp	107	428,753
5	Deferred Rate Case Exp	Liberty Utilities Serv Corp	186	4,730
6	Payroll Reimbursement	Liberty Utilities Serv Corp	234	4,400
7	Government/Civic Activities	Liberty Utilities Serv Corp	426.4	154,004
8	Administrative & General Salaries	Liberty Utilities Serv Corp	920	3,745,952
9	Administrative & General Other Exp	Liberty Utilities Serv Corp	921	200,221
10	A&G Costs to be Billed to Affiliates	Liberty Utilities Serv Corp	922	249,228
11	Indirect Allocations	Liberty Utilities Serv Corp	923	4,506,119
12	Executive Mgmt Labor Exp	Algonquin Pwr & Utilities Corp	920	1,880,291
13	Indirect Allocations	Algonquin Pwr & Utilities Corp	923	3,192,764
14	Prepaid Insurance	Liberty Utilities Canada	165	4,863,311
15	Prepaid Software Expenses	Liberty Utilities Canada	165	104,526
16	Tax Penalty	Liberty Utilities Canada	426.3	489
17	Government/Civic Activities	Liberty Utilities Canada	426.4	918
18	Outside Services & Consulting Fees	Liberty Utilities Canada	923	1,475,443
19	CWIP	Algonquin Power - APCO	107	190,808
20	**Non-power Goods or Services Provided for Affiliate**			
21	Insurance Services	Liberty Utilities Serv Corp	922	478
22	Accounting	Liberty Utilities Serv Corp	922	8,255
23	Financial Planning & Analysis	Liberty Utilities Serv Corp	922	10,476
24	Auditing	Liberty Utilities Serv Corp	922	2,254
25	Customer Service & Support	Liberty Utilities Serv Corp	922	32,644
26	Communications	LIberty Utilities Serv Corp	922	9,393
27	Construction Design	Liberty Utilities Serv Corp	922	70
28	System Performance	Liberty Utilities Serv Corp	922	6,026
29	Transmission Policy & Compliance	Liberty Utilities Serv Corp	922	1,185
30	Utiltiy Planning	Liberty Utilities Serv Corp	922	82,874
31	IT Expenses	Liberty Utilities Serv Corp	922	2,246
32	Purchasing & Stores	LIberty Utilities Serv Corp	922	3,501
33	Regulatory & Planning Exp	Liberty Utilities Serv Corp	922	109,957
34	Human Resources & Benefites Exp	Liberty Utilities Serv Corp	922	104,458
35	Executive A&G Exp	Liberty Utilities Serv Corp	922	389,483
36	Environmental Health & Safety	Liberty Utilities Serv Corp	922	12,006
37	Accounting	Liberty Utilities Serv Corp	922	21,454
38	Payroll & Benefits	Liberty Utilities Serv Corp	922	550,366
39	A&G Costs	Empire Dist Industries Inc	922	420,678
40	Accounts Payable	Empire Dist Industries Inc	922	4,289
41	Pole Attachments	Empire Dist Industries Inc	922	66,244
42	Building Lease	Empire Dist Industries Inc	922	44,222
1	**Non-power Goods or Services Provided by Affiliated**			
2	Fiber Service	Empire Dist Industries Inc	556	1,379,352
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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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)
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20	**Non-power Goods or Services Provided for Affiliate**			
21	Customer Billing	Empire Dist Industries Inc	922	11,740
22	Phone Expense	Empire Dist Industries Inc	922	5,871
23	Purchasing	Empire Dist Industries Inc	922	10,096
24	2-Way Radio Costs	Empire Dist Industries Inc	922	662
25	Tech Support	Empire Dist Industries Inc	922	72,922
26	Transportation Costs	Empire Dist Industries Inc	922	9,057
27	A&G Costs	The Empire Dist Gas Co	922	1,598,997
28	Accounts Payable	The Empire Dist Gas Co	922	21,763
29	Customer Billing	The Empire Dist Gas Co	922	1,040,102
30	Phone Expense	The Empire Dist Gas Co	922	21,629
31	Purchasing	The Empire Dist Gas Co	922	19,472
32	Tech Support	The Empire Dist Gas Co	922	105,093
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APUC is the ultimate corporate parent that provides financial and strategic management, corporate governance, and oversight of administrative and support services to Liberty Utilities (Canada) Corp. ("LUC") and its subsidiaries as well as to Algonquin Power Co. (APCo") d/b/a Liberty Power and its subsidiaries. The services provided by APUC are necessary for all affiliates, including LUC and the regulated utility subsidiaries of Liberty Utilities Co. (referred to as "Liberty Utilities"), to have access to capital markets for capital projects and operations. These services are expensed at APUC and performed for the benefit of Liberty Power and Liberty Utilities and their respective businesses.

APUC and its affiliates benefit from APUC's expertise and access to the capital markets through the use of certain shared services, which maximizes economics of scale and minimizes redundancy. In short, it provides form maximum expertise at lower costs. Further, the use of shared expertise allows each of the entities to receive a benefit it may not be able to achieve on a stand-alone basis such as strategic management advice and access to capital at more competitive rates.

Indirect costs allocated to The Empire District Electric Company from Liberty Utilities Canada and Liberty Utilities Service Corp is based on a 4-factor methodology that is calculated on the previous year-end audited financial statement numbers per region for customer count, operating expense and property, plant and equipment. The amount per region is weighted 40% for customer count, 20% for labor expense, 20% for non-labor expense and 20% net plant.

Costs allocated to The Empire District Gas Company and Empire District Industries Inc from The Empire District Electric Company are billed by unit of service. Each unit of service billing has a calculated rate that is based on various general ledger accounts and costs and is adjusted periodically. Each rate is then applied to the appropriate volume driver to determine the monthly allocation to the business units.

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