THIS FILING IS		
Item 1: [X] An Initial (Original) Submission	OR [ ]	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
Indiana-Kentucky Electric Corporation	End of 2019/Q4

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

IDENTIFICATION

01 Exact Legal Name of Respondent Indiana-Kentucky Electric Corporation	02 Year/Period of Report End of 2019/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)* 3932 U.S. Route 23, Piketon, Ohio 45661	
05 Name of Contact Person Justin J. Cooper	06 Title of Contact Person CFO, Secretary and Treasurer
07 Address of Contact Person *(Street, City, State, Zip Code)* 3932 U.S. Route 23, Piketon, Ohio 45661	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(740) 289-7244	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019

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)*
Justin J. Cooper	Justin J. Cooper	04/24/2020
02 Title CFO, Secretary and Treasurer		

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
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	NONE
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	NA
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	NONE
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	NONE
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	NA
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	NONE
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	NONE
25	Unrecovered Plant and Regulatory Study Costs	230	NONE
26	Transmission Service and Generation Interconnection Study Costs	231	NONE
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	NONE
32	Capital Stock Expense	254	NONE
33	Long-Term Debt	256-257	NONE
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	NONE

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	NONE
44	Sales of Electricity by Rate Schedules	304	NONE
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	NONE
48	Transmission of Electricity for Others	328-330	NONE
49	Transmission of Electricity by ISO/RTOs	331	NONE
50	Transmission of Electricity by Others	332	NONE
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	NONE
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	NONE
57	Amounts included in ISO/RTO Settlement Statements	397	NONE
58	Purchase and Sale of Ancillary Services	398	NONE
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	NONE
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	NONE
65	Pumped Storage Generating Plant Statistics	408-409	NONE
66	Generating Plant Statistics Pages	410-411	NONE

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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	NONE
69	Substations	426-427	NONE
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 Indiana-Kentucky Electric Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* 12/31/2019	Year/Period of Report End of 2019/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.

Justin J. Cooper, CFO, Secretary & Treasurer
3932 U.S. Route 23
P.O. Box 468
Piketon, Ohio 45661

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.

Incorporated in the State of Indiana under Indiana General Corporation Act on October 1, 1952.

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.

Major - Electric Utility - Indiana

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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.

All of the outstanding stock of Indiana-Kentucky Electric Corporation is owned by Ohio Valley Electric Corporation. Ohio Valley Electric Corporation, in turn, is owned by twelve entities consisting of ten investor-owned utilities or utility holding companies and two affiliates of generation and transmission rural electric cooperatives. American Electric Power Company, Inc., and its subsidiary, Columbus Southern Power Company held 43.47% of Ohio Valley Electric Corporation's capital stock at December 31, 2019.

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	Paul Chodak III	
2	Vice President and Chief Operating Officer	Robert A. Osborne	
3	Chief Financial Officer, Secretary and Treasurer	Justin J. Cooper	
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Schedule Page: 104 Line No.: 1 Column: c

Salaries are none.

Schedule Page: 104 Line No.: 2 Column: c

Salaries are none.

Schedule Page: 104 Line No.: 3 Column: c

Salaries are none.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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	Paul Chodak III	1 Riverside Plaza, Columbus, OH 43215
2	Wayne D. Games	One Vectren Square, Evansville, IN 47708
3	Marc E. Lewis	110 East Wayne St., Ft. Wayne, IN 46802
4	David A. Lucas	110 East Wayne St., Ft. Wayne, IN 46802
5	Patrick W. O'Loughlin ***	6677 Busch Blvd., Columbus, OH 43229
6	David W. Pinter ***	76 S. Main St., Akron, OH 44308
7	Toby L. Thomas	110 East Wayne St., Ft. Wayne, IN 46802
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Schedule Page: 105 Line No.: 1 Column: a

Paul Chodak III was elected to replace Mark C. McCullough, effective January 2019.

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.

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

1. Not Applicable
2. Not Applicable
3. Not Applicable
4. Not Applicable
5. Not Applicable
6. None
7. Not Applicable
8. All 2018 employees shared a $1,742,504 bonus that was paid in 2019.
9. Not Applicable
10. Not Applicable
11. Not Applicable
12. See Notes to the Financial Statements beginning on page 122.
13. None
14. Not Applicable

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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	1,400,104,901	1,396,703,251
3	Construction Work in Progress (107)	200-201	2,521,630	3,833,725
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,402,626,531	1,400,536,976
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	781,526,136	747,809,426
6	Net Utility Plant (Enter Total of line 4 less 5)		621,100,395	652,727,550
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)		621,100,395	652,727,550
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)		0	0
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
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)		39,697,566	32,246,811
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)		39,697,566	32,246,811
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		0	0
36	Special Deposits (132-134)		1,000	1,000
37	Working Fund (135)		5,200	5,200
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		0	0
41	Other Accounts Receivable (143)		373,913	763,171
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		0	0
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		0	0
45	Fuel Stock (151)	227	33,957,576	16,360,163
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	15,429,862	16,223,474
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	0

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	0	5,199
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)		965,756	909,841
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		0	0
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		50,733,307	34,268,048
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		0	0
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	17,191,022	16,342,840
73	Prelim. Survey and Investigation Charges (Electric) (183)		3,799,085	3,493,545
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)		10,604	16,705
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	0	251
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)		0	0
82	Accumulated Deferred Income Taxes (190)	234	10,029,850	9,778,741
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		31,030,561	29,632,082
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		742,561,829	748,874,491

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	end of 2019/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	3,400,000	3,400,000
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)		0	0
7	Other Paid-In Capital (208-211)	253	0	0
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	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	0	0
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
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)		3,400,000	3,400,000
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	0	0
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	0	0
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		0	0
24	Total Long-Term Debt (lines 18 through 23)		0	0
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		51,809	85,614
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		0	0
29	Accumulated Provision for Pensions and Benefits (228.3)		19,043,600	20,820,671
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
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)		31,086,402	29,477,156
35	Total Other Noncurrent Liabilities (lines 26 through 34)		50,181,811	50,383,441
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		14,823,397	19,138,598
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		0	0
41	Customer Deposits (235)		1,000	1,000
42	Taxes Accrued (236)	262-263	3,707,534	3,548,286
43	Interest Accrued (237)		0	0
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		-2,416	-554
48	Miscellaneous Current and Accrued Liabilities (242)		7,160,730	4,633,514
49	Obligations Under Capital Leases-Current (243)		73,112	79,536
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		25,763,357	27,400,380
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		624,163,648	637,585,421
57	Accumulated Deferred Investment Tax Credits (255)	266-267	0	0
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	-178	-178
60	Other Regulatory Liabilities (254)	278	29,023,341	20,326,688
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		4,776,777	5,462,749
64	Accum. Deferred Income Taxes-Other (283)		5,253,073	4,315,990
65	Total Deferred Credits (lines 56 through 64)		663,216,661	667,690,670
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		742,561,829	748,874,491

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	264,778,887	258,738,544		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	177,692,565	181,470,733		
5	Maintenance Expenses (402)	320-323	43,841,200	43,334,845		
6	Depreciation Expense (403)	336-337	42,456,518	26,441,458		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337				
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	5,423,809	5,264,851		
15	Income Taxes - Federal (409.1)	262-263				
16	- Other (409.1)	262-263				
17	Provision for Deferred Income Taxes (410.1)	234, 272-277				
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277				
19	Investment Tax Credit Adj. - Net (411.4)	266				
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)					
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)		269,414,092	256,511,887		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		-4,635,205	2,226,657		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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
264,778,887	258,738,544					2
						3
177,692,565	181,470,733					4
43,841,200	43,334,845					5
42,456,518	26,441,458					6
						7
						8
						9
						10
						11
						12
						13
5,423,809	5,264,851					14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
269,414,092	256,511,887					25
-4,635,205	2,226,657					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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)		-4,635,205	2,226,657		
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)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		4,677,751	-2,187,540		
38	Allowance for Other Funds Used During Construction (419.1)					
39	Miscellaneous Nonoperating Income (421)		6,260	18,468		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		4,684,011	-2,169,072		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		38,581	46,160		
46	Life Insurance (426.2)					
47	Penalties (426.3)		250			
48	Exp. for Certain Civic, Political & Related Activities (426.4)					
49	Other Deductions (426.5)					
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		38,831	46,160		
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				
54	Income Taxes-Other (409.2)	262-263				
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277				
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277				
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)					
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		4,645,180	-2,215,232		
61	Interest Charges					
62	Interest on Long-Term Debt (427)					
63	Amort. of Debt Disc. and Expense (428)					
64	Amortization of Loss on Reaquired Debt (428.1)					
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)					
68	Other Interest Expense (431)		9,975	11,425		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)					
70	Net Interest Charges (Total of lines 62 thru 69)		9,975	11,425		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)					
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)					

Name of Respondent Indiana-Kentucky Electric Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/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)		
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	42,456,518	26,441,458
5	Amortization of		
6	(Gain)/Loss on Marketable Securities	-2,970,631	3,427,283
7			
8	Deferred Income Taxes (Net)		
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	389,258	-397,114
11	Net (Increase) Decrease in Inventory	-16,803,800	7,621,072
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-1,420,978	1,776,881
14	Net (Increase) Decrease in Other Regulatory Assets	-848,182	1,030,804
15	Net Increase (Decrease) in Other Regulatory Liabilities	-6,355,412	5,952,467
16	(Less) Allowance for Other Funds Used During Construction		
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Decommissioning and Demolition	5,842,809	1,525,346
19	Principal Payments Under Capital Leases	-90,730	-88,960
20	Prepaid Expenses and Other	-44,363	10,244
21	Other Liabilities	-201,630	-4,102,210
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	19,952,859	43,197,271
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-3,763,625	-4,371,088
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		
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-3,763,625	-4,371,088
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		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-12,963,193	-15,564,643
45	Proceeds from Sales of Investment Securities (a)	8,483,068	10,447,671

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):		
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-8,243,750	-9,488,060
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68	Advances From Parent	-11,709,109	-33,709,211
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	-11,709,109	-33,709,211
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock		
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-11,709,109	-33,709,211
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)		
87			
88	Cash and Cash Equivalents at Beginning of Period	6,200	6,200
89			
90	Cash and Cash Equivalents at End of period	6,200	6,200

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.

This FERC Form 1 represents the financial statements of Indiana-Kentucky Electric Corporation at December 31, 2019. Indiana-Kentucky Electric Corporation's financial statements have been prepared in conformity with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than generally accepted accounting principles. The following areas represent significant differences between the Uniform System of Accounts and generally accepted accounting principles: (1) the disclosure of certain significant non-cash transactions, (2) the presentation of current and non-current portions of long-term debt, and certain other assets and liabilities, (3) the presentation of preliminary survey and investigation charges, and (4) the gross presentation of certain regulatory assets and regulatory liabilities.

Indiana-Kentucky Electric Corporation considered the income tax footnote requirements as prescribed by the FERC in paragraph 38 of Policy Statement PL19-2-000, Accounting and Ratemaking Treatment of Accumulated Deferred Income Taxes and Treatment Following the Sale or Retirement of an Asset. The Notes to the Consolidating Financial Statements included herein reflect those requirements. Due to the valuation allowance on the net deferred tax assets, the Company did not have any excess deferred income taxes.

Generally accepted accounting principles require that the current and non-current portions of assets and liabilities be appropriately identified and reported as such on the balance sheet. FERC requires that certain items such as long-term debt, regulatory assets, and regulatory liabilities be reported as set forth in the Uniform System of Accounts and published accounting releases, which does not recognize any segregation between the current and non-current portions of these items for reporting purposes.

Generally accepted accounting principles require that preliminary survey and investigation charges be recorded as a component of construction work in progress. FERC requires that these items be reported as set forth in the Uniform System of Accounts and published accounting releases, which require preliminary survey and investigation charges be recorded as a deferred debit.

Generally accepted accounting principles allow for net presentation of certain regulatory assets and liabilities when the legal right of offset exists. FERC requires that these items be reported as set forth in the Uniform System of Accounts and published accounting releases, which require gross presentation of certain regulatory assets and liabilities. FERC also requires certain deferred tax assets and liabilities be presented gross in the balance sheet, whereas U.S. GAAP requires netting of deferred tax assets and liabilities to the extent they arise from the same tax jurisdiction.

Indiana-Kentucky Electric Corporation presents fuel and emission allowances consumed in operation and other operation on the income statement of its audited financial statements. FERC requires all of these expenses to be presented as operation expenses.

Generally accepted accounting principles require principal payments on capital leases to be included in financing activities on the statement of cash flows. FERC requires these payments to be included in operating activities.

Indiana-Kentucky Electric Corporation's Notes to Consolidating Financial Statements have been prepared in conformity with generally accepted accounting principles. Accordingly, certain footnotes do not tie directly to amounts in Indiana-Kentucky Electric Corporation's Financial Statements contained herein.

Management has evaluated the impact of events occurring after December 31, 2019 up to April 24, 2020. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATING FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2019 AND 2018

1. ORGANIZATION AND SIGNIFICANT ACCOUNTING POLICIES

Consolidating Financial Statements—The consolidating financial statements include the accounts of Ohio Valley Electric Corporation (OVEC) and its wholly owned subsidiary, Indiana-Kentucky Electric Corporation (IKEC), collectively, the Companies. All intercompany transactions have been eliminated in consolidation.

Organization—The Companies own two generating stations located in Ohio and Indiana with a combined electric production capability of approximately 2,256 megawatts. OVEC is owned by several investor-owned utilities or utility holding companies and two affiliates of generation and transmission rural electric cooperatives. These entities or their affiliates comprise the Sponsoring Companies. The Sponsoring Companies purchase power from OVEC according to the terms of the Inter-Company Power Agreement (ICPA), which has a current termination date of June 30, 2040. Approximately 24% of the Companies' employees are covered by a collective bargaining agreement that expires on August 31, 2021.

Prior to 2004, OVEC's primary commercial customer was the U.S. Department of Energy (DOE). The contract to provide OVEC-generated power to the DOE was terminated in 2003 and all obligations were settled at that time. Currently, OVEC has an agreement to arrange for the purchase of power (Arranged Power), under the direction of the DOE, for resale directly to the DOE. The current agreement with the DOE was executed on July 11, 2018, for one year, with the option for the DOE to extend the agreement at the anniversary date. The agreement was extended on July 11, 2019, for one year. OVEC anticipates that this agreement will continue until 2022. All purchase costs are billable by OVEC to the DOE.

Rate Regulation—The proceeds from the sale of power to the Sponsoring Companies are designed to be sufficient for OVEC to meet its operating expenses and fixed costs, as well as earn a return on equity before federal income taxes. In addition, the proceeds from power sales are designed to cover debt amortization and interest expense associated with financings. The Companies have continued and expect to continue to operate pursuant to the cost-plus rate of return recovery provisions at least to June 30, 2040, the date of termination of the ICPA. In 2014, to promote reduced costs, the Companies reduced their billings under the ICPA to effectively forego recovery of the equity return through the ICPA billings. However, in 2018, the Companies discontinued this practice and are once again recovering the equity return through the ICPA billings.

The accounting guidance for Regulated Operations provides that rate-regulated utilities account for and report assets and liabilities consistent with the economic effect of the way in which rates are established, if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can be charged and collected. The Companies follow the accounting and reporting requirements in accordance with the guidance for Regulated Operations. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income are deferred in the accompanying consolidating balance sheets and are recognized as income as the related amounts are included in service rates and recovered from or refunded to customers.

The Companies' regulatory assets, liabilities, and amounts authorized for recovery through Sponsor billings at December 31, 2019 and 2018, were as follows:

	2019		2018	
	OVEC	**IKEC**	**OVEC**	**IKEC**
Regulatory assets:				
Noncurrent regulatory assets:				
Unrecognized postemployment benefits	$ 2,181,535	$ 3,020,001	$ 2,464,412	$ 1,683,544
Unrecognized pension benefits	17,999,287	14,171,021	19,235,029	14,659,296
Decommissioning, demolition and other	-	-	8,721,689	-
Total	20,180,822	17,191,022	30,421,130	16,342,840
Total regulatory assets	$ 20,180,822	$ 17,191,022	$ 30,421,130	$ 16,342,840
Regulatory liabilities:				
Current regulatory liabilities:				
Deferred revenue—advances for construction	$ 3,569,187	$ 2,613,624	$ 1,698,020	$ 4,326,289
Deferred credit—advance collection of interest	1,494,593	-	1,633,482	-
Total	5,063,780	2,613,624	3,331,502	4,326,289
Noncurrent regulatory liabilities:				
Postretirement benefits	55,801,088	20,361,710	46,151,192	17,507,866
Income taxes refundable to customers	8,658,897	-	11,571,428	-
Advance billing of debt reserve	90,000,000	-	60,000,000	-
Decommissioning, demolition and other	6,056,530	8,661,631	-	2,818,822
Total	160,516,515	29,023,341	117,722,620	20,326,688
Total regulatory liabilities	$ 165,580,295	$ 31,636,965	$ 121,054,122	$ 24,652,977

Regulatory Assets—Regulatory assets consist primarily of pension benefit costs, postemployment benefit costs, and accrued decommissioning and demolition costs to be billed to the Sponsoring Companies in future years. The Companies' current billing policy for pension and postemployment benefit costs is to bill its actual plan funding.

Regulatory Liabilities—The regulatory liabilities classified as current in the accompanying consolidating balance sheet as of December 31, 2019, consist primarily of interest expense collected from customers in advance of expense recognition and customer billings for construction in progress. These amounts will be credited to customer bills during 2020. Other regulatory liabilities consist primarily of postretirement benefit costs and decommissioning and demolition costs that have been billed to customers in excess of cumulative expense recognition, income taxes refundable to customers that will be credited to bills over a long-term basis, and advanced billings collected from the Sponsoring Companies for debt service.

The regulatory liability for postretirement benefits recorded at December 31, 2019 and 2018, represents amounts collected in historical billings in excess of the accounting principles generally accepted in the United States of America (GAAP) net periodic benefit costs, including a termination payment from the DOE in 2003 for unbilled postretirement benefit costs, and incremental unfunded plan obligations recognized in the balance sheets but not yet recognizable in GAAP net periodic benefit costs. Related regulatory liabilities are being credited to customer bills on a long-term basis.

In January 2017, the Companies started advance billing the Sponsoring Companies for debt service as allowed under the ICPA. As of December 31, 2019 and 2018, $90 million and $60 million, respectively, had been advance billed to the Sponsoring Companies. As the Companies have not yet incurred the related costs, a regulatory liability was recorded which will be credited to customer bills on a long-term basis.

Cash and Cash Equivalents—Cash and cash equivalents primarily consist of cash and money market funds and their carrying value approximates fair value. For purposes of these statements, the Companies consider temporary cash investments to be cash equivalents since they are readily convertible into cash and have original maturities of less than three months.

Electric Plant—Property additions and replacements are charged to utility plant accounts. Depreciation expense is recorded at the time property additions and replacements are billed to customers or at the date the property is placed in service if the in-service date occurs subsequent to the customer billing. Customer billings for construction in progress are recorded as deferred revenue—advances for construction. These amounts are closed to revenue at the time the related property is placed in service. Depreciation expense and accumulated depreciation are recorded when financed property additions and replacements are recovered over a period of years through customer debt retirement billing. All depreciable property will be fully billed and depreciated prior to the expiration of the ICPA. Repairs of property are charged to maintenance expense.

Fuel in Storage, Emission Allowances, and Materials and Supplies—The Companies maintain coal, reagent, and oil inventories, as well as emission allowances, for use in the generation of electricity for regulatory compliance purposes due to the generation of electricity. These inventories are valued at average cost. Materials and supplies consist primarily of replacement parts necessary to maintain the generating facilities and are valued at average cost.

Long-Term Investments—Long-term investments consist of marketable securities that are held for the purpose of funding decommissioning and demolition costs, debt service, potential postretirement funding, and other costs. These debt securities have been classified as trading securities in accordance with the provisions of the accounting guidance for Investments—Debt and Equity Securities. Debt and equity securities reflected in long-term investments are carried at fair value with the unrealized gain or loss, reported in Other Income (Expense). The cost of securities sold is based on the specific identification cost method. The fair value of most investment securities is determined by reference to currently available market prices. Where quoted market prices are not available, the Companies use the market price of similar types of securities that are traded in the market to estimate fair value. See Fair Value Measurements in Note 10. Long-term investments primarily consist of municipal bonds, money market mutual fund investments, and mutual funds. Net unrealized gains (losses) recognized during 2019 and 2018 on securities still held at the balance sheet date were $16,445,716 and ($12,968,851), respectively.

Fair Value Measurements of Assets and Liabilities—The accounting guidance for Fair Value Measurements and Disclosures establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). Where observable inputs are available, pricing may be completed using comparable securities, dealer values, and general market conditions to determine fair value. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, and other observable inputs for the asset or liability.

Unamortized Debt Expense—Unamortized debt expense relates to costs incurred in connection with obtaining revolving credit agreements. These costs are being amortized over the term of the related revolving credit agreement and are recorded as an asset in the consolidating balance sheets. Costs incurred to issue debt are recorded as a reduction to long-term debt as presented in Note 6.

Asset Retirement Obligations and Asset Retirement Costs—The Companies recognize the fair value of legal obligations associated with the retirement or removal of long-lived assets at the time the obligations are incurred and can be reasonably estimated. The initial recognition of this liability is accompanied by a corresponding increase in depreciable electric plant. Subsequent to the initial recognition, the liability is adjusted for any revisions to the expected value of the retirement obligation (with corresponding adjustments to electric plant) and for accretion of the liability due to the passage of time.

These asset retirement obligations are primarily related to obligations associated with future asbestos abatement at certain generating stations and certain plant closure costs, including the impacts of the coal combustion residuals rule.

	OVEC	IKEC	Consolidated
Balance—January 1, 2018	$ 29,218,810	$ 27,951,810	$ 57,170,620
Accretion	1,550,716	1,525,346	3,076,062
Liabilities settled	-	-	-
Revisions to cash flows	-	-	-
Balance—December 31, 2018	30,769,526	29,477,156	60,246,682
Accretion	1,648,398	1,626,864	3,275,262
Liabilities settled	(17,288)	(17,618)	(34,906)
Revisions to cash flows	-	-	-
Balance—December 31, 2019	$ 32,400,636	$ 31,086,402	$ 63,487,038

During 2017, the Companies completed an updated study to estimate the asset retirement costs described above. The revised estimated costs are recorded in the accompanying balance sheets. Adjustments resulting from the revised estimated costs are included as revisions to cash flows in the above table. The increase in the asset retirement obligation is primarily the result of proposed regulations related to the disposal of coal combustion residuals, as further discussed in Note 9.

The Companies do not recognize liabilities for asset retirement obligations for which the fair value cannot be reasonably estimated. The Companies have asset retirement obligations associated with transmission assets. However, the retirement date for these assets cannot be determined; therefore, the fair value of the associated liability currently cannot be estimated and no amounts are recognized in the consolidating financial statements herein.

Income Taxes—The Companies use the liability method of accounting for income taxes. Under the liability method, the Companies provide deferred income taxes for all temporary differences between the book and tax basis of assets and liabilities, which will result in a future tax consequence. The Companies account for uncertain tax positions in accordance with the accounting guidance for Income Taxes.

Use of Estimates—The preparation of consolidating financial statements in conformity with 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 consolidating financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenue Recognition—In May 2014, the FASB issued Revenue from Contracts with Customers, Topic 606 (ASU No. 2014-09), which provides a new framework for the recognition of revenue. The standard's core principle is that a company will recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. The Companies implemented the guidance on a modified retrospective basis on January 1, 2018. Revenue for the reporting periods beginning after December 31, 2017, are recorded and disclosed in accordance with Topic 606, while prior period results have not been adjusted and continue to be reported in accordance with prior accounting guidance. The Companies did not make any adjustments to the January 1, 2018, opening balances as a result of adoption, and the implementation had no impact on the Companies' consolidating financial statements.

Performance obligations related to the sale of electric energy are satisfied over time as system resources are made available to customers and as energy is delivered to customers and the Companies recognize revenue upon billing the customer.

The Companies have three contracts with customers resulting in three types of revenue. These three contracted revenue types are:

1) Sales of Electric Energy to Department of Energy
Sales of Electric Energy to Sponsoring Companies
2) Sales of Electric Energy to Pennsylvania, Jersey, Maryland Power Pool (PJM)

The performance obligations and recognition of revenue are similar and both individually and, in the aggregate were not materially impacted by the implementation of Topic 606. The Companies have no contract assets or liabilities as of December 31, 2019. The following table provides information about the Companies' receivables and unbilled revenue from contracts with customers:

	OVEC		IKEC		Consolidated	
	Accounts Receivable	Unbilled	Accounts Receivable	Unbilled	Accounts Receivable	Unbilled
Beginning balance as of January 1, 2018	$ 40,368,102	$ 5,454,632	$ 366,235	$ -	$ 40,737,337	$ 5,454,632
Ending balance as of December 31, 2018	63,515,547	5,098,515	763,349	-	64,278,896	5,098,515
Increase/(decrease)	$ 23,147,445	$ (356,117)	$ 397,114	$ -	$ 23,544,559	$ (356,117)
Beginning balance as of January 1, 2019	$ 63,515,547	$ 5,098,515	$ 763,349	$ -	$ 64,278,896	$ 5,098,515
Ending balance as of December 31, 2019	74,112,598	5,611,960	374,091	-	$ 74,486,689	$ 5,611,960
Increase/(decrease)	$ 10,597,051	$ 513,445	$ (389,258)	$ -	$ 10,207,793	$ 513,445

Recently Issued Accounting Standards—In June 2016, the FASB issued ASU 2016-13, *Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*. The pronouncement changes the impairment model for most financial assets, replacing the current "incurred loss" model. ASU 2016-13 will require the use of an "expected loss" model for instruments measured at amortized cost and will also require entities to record allowances for available-for-sale debt securities rather than reduce the carrying amount. The Companies plan to adopt the standard for the fiscal year ended December 31, 2020. The Companies are in the process of evaluating the impact of adoption, if any, of this ASU on the Companies' consolidating financial statements.

See adoption of ASC 842, *Leases*, in Note 11.

Subsequent Events—In preparing the accompanying financial statements and disclosures, the Companies reviewed subsequent events through April 17, 2020, which is the date the consolidating financial statements were issued.

Subsequent to December 31, 2019, the World Health Organization declared the ongoing expansion of an existing outbreak of the SARS-CoV-2 virus, named the coronavirus 2019 ("COVID-19"), a pandemic. As a result of the evolving situation and increasing number of cases, many countries have taken various steps in an attempt to curtail or slow COVID-19's spread, including limiting or ceasing international and domestic travel, slowing or ceasing production activity, and lockdowns or shelter-in-place orders. The Companies are currently unable to predict the duration or extent of any business disruption, changes in law and/or regulation, and uncertainty regarding government and regulatory policy that may occur as a result of these events. COVID-19 has also caused significant volatility and declines in value to most financial markets, which will have a near-term impact on the value of the Companies' long-term investments and investments related to benefit obligations. As there are no comparable recent events which may provide guidance as to the effect of the spread of COVID-19, the Companies are unable to estimate the impact that COVID-19 will have on its financial results at this time.

2. RELATED-PARTY TRANSACTIONS

Transactions with the Sponsoring Companies during 2019 and 2018 included the sale of all generated power to them, the purchase of Arranged Power from them, and other utility systems in order to meet the DOE's power requirements, contract barging services, railcar services, and minor transactions for services and materials. The Companies have Power Agreements with Louisville Gas and Electric Company, Duke Energy Ohio, Inc., The Dayton Power and Light Company, Kentucky Utilities Company, Ohio Edison Company, and American Electric Power Service Corporation as agent for the American Electric Power System Companies; and Transmission Service Agreements with Louisville Gas and Electric Company, Duke Energy Ohio, Inc., The Dayton Power and Light Company, The Toledo Edison Company, Ohio Edison Company, Kentucky Utilities Company, and American Electric Power Service Corporation as agent for the American Electric Power System Companies.

At December 31, 2019 and 2018, balances due from the Sponsoring Companies are as follows:

	2019	2018
Accounts receivable	$ 66,926,922	$ 57,442,759

During 2019 and 2018, American Electric Power accounted for approximately 44% of operating revenues from Sponsoring Companies and Buckeye Power accounted for 18%. No other Sponsoring Company accounted for more than 10%.

American Electric Power Company, Inc. and subsidiary companies owned 43.47% of the common stock of OVEC as of December 31, 2019. The following is a summary of the principal services received from the American Electric Power Service Corporation as authorized by the Companies' Boards of Directors:

	2019	2018
General services	$ 4,830,104	$ 4,917,608
Specific projects	119,157	472,862
Total	$ 4,949,261	$ 5,390,470

General services consist of regular recurring operation and maintenance services. Specific projects primarily represent nonrecurring plant construction projects and engineering studies, which are approved by the Companies' Boards of Directors. The services are provided in accordance with the service agreement dated December 15, 1956, between the Companies and the American Electric Power Service Corporation.

3. COAL SUPPLY

The Companies have coal supply agreements with certain nonaffiliated companies that expire at various dates from the year 2020 through 2022. Pricing for coal under these contracts is subject to contract provisions and adjustments. The Companies currently have 100% of their 2020 coal requirements under contract. These contracts are based on rates in effect at the time of contract execution. Our total obligations under these agreements as of December 31, 2019, are included in the table below:

	OVEC	IKEC	Consolidated
2020	$ 98,990,000	$ 114,136,750	$ 213,126,750
2021	57,290,000	78,586,000	$ 135,876,000
2022	50,340,000	-	$ 50,340,000

4. ELECTRIC PLANT

Electric plant at December 31, 2019 and 2018, consists of the following:

	2019		2018	
	OVEC	IKEC	OVEC	IKEC
Steam production plant	$ 1,329,475,024	$ 1,369,093,484	$ 1,324,643,898	$ 1,366,099,602
Transmission plant	51,994,163	29,992,395	51,994,163	29,584,627
General plant	11,897,781	1,011,382	11,906,069	1,011,382
Intangible	18,924	7,640	18,924	7,640
	1,393,385,892	1,400,104,901	1,388,563,054	1,396,703,251
Less accumulated depreciation	782,253,926	781,526,136	752,374,469	747,809,426
	611,131,966	618,578,765	636,188,585	648,893,825
Construction in progress	6,888,117	6,320,715	3,745,843	7,327,269
Total electric plant	$ 618,020,083	$ 624,899,480	$ 639,934,428	$ 656,221,094

All property additions and replacements are fully depreciated on the date the property is placed in service, unless the addition or replacement relates to a financed project. As the Companies' policy is to bill in accordance with the debt service schedule under the debt agreements, all financed projects are being depreciated in amounts equal to the principal payments on outstanding debt.

5. BORROWING ARRANGEMENTS AND NOTES

OVEC had a $200 million revolving credit facility set to expire in November 2019, which was replaced on April 25, 2019, by a new revolving credit facility of $185 million with an expiration date of April 25, 2022. At December 31, 2019 and 2018, OVEC had borrowed $80 million and $85 million, respectively, under lines of credit. Interest expense related to lines of credit borrowings was $3,757,148 in 2019 and $3,448,137 in 2018. During 2019 and 2018, OVEC incurred annual commitment fees of $268,285 and $318,885, respectively, based on the borrowing limits of the line of credit.

6. LONG-TERM DEBT

The following amounts were outstanding at December 31, 2019 and 2018:

	Interest Rate Type	Interest Rate	2019	2018
Senior 2006 Notes:				
2006A due February 15, 2026	Fixed	5.80 %	$ 168,569,904	$ 189,381,919
2006B due June 15, 2040	Fixed	6.40	54,142,874	55,360,136
Senior 2007 Notes:				
2007A-A due February 15, 2026	Fixed	5.90	74,610,818	84,386,325
2007A-B due February 15, 2026	Fixed	5.90	18,790,003	21,251,868
2007A-C due February 15, 2026	Fixed	5.90	18,939,620	21,421,088
2007B-A due June 15, 2040	Fixed	6.50	27,012,831	27,630,240
2007B-B due June 15, 2040	Fixed	6.50	6,802,916	6,958,404
2007B-C due June 15, 2040	Fixed	6.50	6,857,084	7,013,810
Senior 2008 Notes:				
2008A due February 15, 2026	Fixed	5.92	23,292,665	26,342,332
2008B due February 15, 2026	Fixed	6.71	47,301,931	53,467,070
2008C due February 15, 2026	Fixed	6.71	49,367,759	55,446,166
2008D due June 15, 2040	Fixed	6.91	39,387,935	40,230,351
2008E due June 15, 2040	Fixed	6.91	40,072,323	40,929,376
Series 2009 Bonds:				
2009A due February 15, 2026	Fixed	2.88	25,000,000	-
2009B due February 1, 2026	Floating	3.31	25,000,000	25,000,000
2009C due February 1, 2026	Floating	3.31	25,000,000	25,000,000
2009D due February 1, 2026	Floating	1.46	25,000,000	25,000,000
2009E due October 1, 2019	Fixed	5.63	-	100,000,000
Series 2010 Bonds:				
2010A due February 1, 2040	Floating	6.23	50,000,000	50,000,000
2010B due February 1, 2040	Floating	3.31	50,000,000	50,000,000
Series 2012 Bonds:				
2012A due June 1, 2032	Fixed	5.00	76,800,000	76,800,000
2012A due June 1, 2039	Fixed	5.00	123,200,000	123,200,000
2012B due June 1, 2040	Floating	6.23	50,000,000	50,000,000
2012C due June 1, 2040	Floating	6.23	50,000,000	50,000,000
Series 2017 Notes:				
2017A due August 4, 2022	Floating	6.23	100,000,000	100,000,000
Series 2019 Bonds:				
2019A due September 1, 2029	Fixed	3.25	100,000,000	-
Total debt			1,275,148,663	1,304,819,085
Total premiums and discounts (net)			(437,865)	(460,465)
Less unamortized debt expense			(13,754,586)	(14,618,729)
Total debt net of premiums, discounts, and unamortized debt expense			1,260,956,212	1,289,739,891

All of the OVEC amortizing unsecured senior notes have maturities scheduled for February 15, 2026, or June 15, 2040, as noted in the previous table.

In 2009, the Ohio Air Quality Development Authority (the "OAQDA") issued the variable-rate, non-amortizing, tax-exempt State of Ohio Air Quality Revenue Bonds (Ohio Valley Electric Corporation Project) in four series (Series 2009A, Series 2009B, Series 2009C and Series 2009D) of $25 million each (the "Series 2009A Bonds," the "Series 2009B Bonds," the "Series 2009C Bonds" and the "Series 2009D Bonds") and

$100 million fixed-rate non-amortizing tax-exempt State of Ohio Air Quality Revenue Bonds (Ohio Valley Electric Corporation Project) (the "Series 2009E Bonds"), the proceeds of which were used to finance a portion of OVEC's costs of acquiring, constructing and installing certain solid waste disposal facilities comprising "air quality facilities," as defined in Chapter 3706, Ohio Revised Code, as amended, for Units 1-5 of the Kyger Creek Plant. OVEC is obligated to make payments under loan agreements between OVEC and OAQDA equal to the principal and interest payments due on such bonds, among other payments.

The Series 2009B and Series 2009C Bonds were remarketed in August 2016, for a five-year interest period that extends to August 25, 2021. The Series 2009A Bonds were secured by an irrevocable transferable direct-pay letter of credit at December 31, 2016, but were repurchased by OVEC on February 6, 2017. Further, the Series 2009D Bonds were secured by an irrevocable transferable direct-pay letter of credit that expired on November 14, 2019. On August 14, 2019, the Series 2009A Bonds and Series 2009D Bonds were each reoffered with a fixed interest rate of 2.875% per annum for the period beginning on August 28, 2019 and ending on February 1, 2026. In addition, the Series 2009E Bonds, which were scheduled to mature on October 1, 2019, were refunded with the proceeds of the Series 2019A Bonds (as defined below).

In December 2010, OVEC established a borrowing facility under which OVEC borrowed, in 2011, $100 million variable-rate bonds due on February 1, 2040. In June 2011, the $100 million variable-rate bonds were reissued by the Indiana Finance Authority (the "IFA") as two series of $50 million variable-rate, non-amortizing, tax-exempt bonds: the Series 2010A Bonds, with an interest period of three years and the Series 2010B Bonds, with an interest period of five years. The Series 2010B Bonds were remarketed in August 2016 for another five-year interest period ending on August 25, 2021. The Series 2010A Bonds were remarketed in June 2014 for a three-year period and in September 2017 for another three-year period that extends to August 4, 2020. The Series 2010A Bonds are to be refinanced in 2020. The Series 2010B Bonds are not being reoffered at this time.

During 2012, the IFA issued $200 million fixed-rate, tax-exempt Midwestern Disaster Relief Revenue Bonds (Ohio Valley Electric Corporation Project) (the "Series 2012A Bonds") and two series of $50 million each, variable-rate, tax-exempt bonds: the Series 2012B Bonds and the Series 2012C Bonds. The Series 2012A Bonds will begin amortizing on June 1, 2027, up to its maturity date. OVEC is obligated to make payments under loan agreements between OVEC and the IFA equal to the principal and interest payments due on such bonds, among other payments.

In 2017, the Series 2012B Bonds and the Series 2012C Bonds, which had been secured by irrevocable transferable direct-pay letters of credit, were remarketed with four-year and five-year interest periods expiring August 4, 2021 and August 4, 2022, respectively.

During 2017, OVEC issued $100 million 2017A variable-rate non-amortizing unsecured senior notes ("2017A Notes") to refinance and retire a 2013 series of notes ("2013A Notes"). The 2013A Notes had an original maturity date of February 15, 2018. The 2017A Notes have an annual repayment of $33,333,333 on August 4, 2020, August 4, 2021, and at the maturity date of August 4, 2022.

In August 2019, OVEC refinanced or refunded $150 million in tax-exempt bonds as follows: (i) the OAQDA issued the State of Ohio Air Quality Revenue Refunding Bonds (Ohio Valley Electric Corporation Project), Series 2019A in an aggregate principal amount of $100 million (the "Series 2019A Bonds"), with a fixed interest rate of 3.25% per annum for the period beginning August 28, 2019 to September 1, 2029, the proceeds of which were used to refund the Series 2009E Bonds, (ii) the Series 2009A Bonds were reoffered in an aggregate principal amount of $25 million and (iii) the Series 2009D Bonds were reoffered in an aggregate principal amount of $25 million.

The annual maturities of long-term debt as of December 31, 2019, are as follows:

2020	$ 141,387,803
2021	244,982,570
2022	148,800,891
2023	69,523,395
2024	73,831,592
2025–2040	596,622,412
Total	$ 1,275,148,663

Note that the 2020 maturities of long-term debt include $50 million variable-rate bonds with agreements expiring in August 2020.

7. INCOME TAXES

OVEC and IKEC file a consolidated federal income tax return. The effective tax rate varied from the statutory federal income tax rate due to differences between the book and tax treatment of various transactions as follows:

	2019	2018
Income tax expense at statutory rate (21% 2019, 21% 2018)	$ 29,980	$ 818,261
Temporary differences flowed through to customer bills	(2,948,492)	(823,343)
Permanent differences and other	5,981	5,082
Income tax provision	$ (2,912,531)	$ -

Components of the income tax provision were as follows:

	2019	2018
Current income tax expense—federal	$ (2,912,531)	$ -
Current income tax (benefit)/expense—state	-	-
Deferred income tax expense/(benefit)—federal	-	-
Total income tax provision	$ (2,912,531)	$ -

OVEC and IKEC record deferred tax assets and liabilities based on differences between book and tax basis of assets and liabilities measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. Deferred tax assets and liabilities are adjusted for changes in tax rates.

To the extent that the Companies have not reflected credits in customer billings for deferred tax assets, they have recorded a regulatory liability representing income taxes refundable to customers under the applicable agreements among the parties. These temporary differences will be credited to the Sponsoring Companies through future power billings. The regulatory liability was $8,658,898 and $11,571,429 at December 31, 2019 and 2018, respectively.

Deferred income tax assets (liabilities) at December 31, 2019 and 2018, consisted of the following:

	2019	2018
Deferred tax assets:		
Deferred revenue—advances for construction	$ 1,299,537	$ 1,265,885
Federal net operating loss carryforwards	39,691,784	49,663,022
Postretirement benefit obligation	891,785	2,140,505
Pension liability	7,034,974	6,447,661
Postemployment benefit obligation	1,093,288	871,608
Asset retirement obligations	13,344,057	12,659,609
Advanced collection of interest and debt service	19,230,828	12,951,016
Miscellaneous accruals	1,154,630	1,183,464
Regulatory liability—postretirement benefits	16,008,318	13,376,650
Regulatory liability—asset retirement costs	3,093,544	-
Regulatory liability—income taxes refundable to customers	4,549,301	5,484,284
Total deferred tax assets	107,392,046	106,043,704
Deferred tax liabilities:		
Prepaid expenses	(384,597)	(352,638)
Electric plant	(81,887,070)	(81,674,810)
Unrealized gain/loss on marketable securities	(4,348,230)	(855,225)
Regulatory asset—pension benefits	(6,719,696)	(7,122,200)
Regulatory asset—asset retirement costs	-	(1,240,367)
Regulatory asset—unrecognized postemployment benefits	(1,093,288)	(871,608)
Total deferred tax liabilities	(94,432,881)	(92,116,848)
Valuation allowance	(12,959,165)	(13,926,856)
Deferred income tax assets	$ -	$ -

Because future taxable income may prove to be insufficient to recover the Companies' deferred tax assets, the Companies have recorded a valuation allowance for their deferred tax assets as of December 31, 2019 and 2018. During 2016, due to a change in federal tax law, the Companies recorded as receivables certain AMT credit carryforwards that the Companies expect to claim as refundable credits in their 2018–2022 federal income tax returns. The amount of the refundable AMT credit is reflected as a current receivable of $2,307,341 and a non-current receivable of $2,307,341 for a total receivable of $4,614,682.

The accounting guidance for Income Taxes addresses the determination of whether the tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under this guidance, the Companies may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. The Companies have not identified any uncertain tax positions as of December 31, 2019 and 2018, and accordingly, no liabilities for uncertain tax positions have been recognized.

The Companies file income tax returns with the Internal Revenue Service and the states of Ohio, Indiana, and the Commonwealth of Kentucky. The Companies are no longer subject to federal tax examinations for tax years 2015 and earlier. The Companies are no longer subject to State of Indiana tax examinations for tax years 2015 and earlier. The Companies are no longer subject to Ohio and the Commonwealth of Kentucky examinations for tax years 2014 and earlier. The Companies have $189,008,494 of Federal Net Operating Loss carryovers that begin to expire in 2032.

8. PENSION PLAN AND OTHER POSTRETIREMENT AND POSTEMPLOYMENT BENEFITS

The Companies have a noncontributory qualified defined benefit pension plan (the Pension Plan) covering substantially all of their employees hired prior to January 1, 2015. The benefits are based on years of service and each employee's highest consecutive 36-month compensation period. Employees are vested in the Pension Plan after five years of service with the Companies.

Funding for the Pension Plan is based on actuarially determined contributions, the maximum of which is generally the amount deductible for income tax purposes and the minimum being that required by the Employee Retirement Income Security Act of 1974, as amended.

In addition to the Pension Plan, the Companies provide certain health care and life insurance benefits (Other Postretirement Benefits) for retired employees. Substantially, all of the Companies' employees hired prior to January 1, 2015, become eligible for these benefits if they reach retirement age while working for the Companies. These and similar benefits for active employees are provided through employer funding and insurance policies. In December 2004, the Companies established VEBA trusts. In January 2011, the Companies established an Internal Revenue Code Section 401(h) account under the Pension Plan.

The full cost of the pension benefits and other postretirement benefits has been allocated to OVEC and IKEC in the accompanying consolidating financial statements. The allocated amounts represent approximately a 56% and 44% split between OVEC and IKEC, respectively, as of December 31, 2019, and approximately a 57% and 43% split between OVEC and IKEC, respectively, as of December 31, 2018.

The Pension Plan's assets as of December 31, 2019, consist of investments in equity and debt securities. All of the trust funds' investments for the pension and postemployment benefit plans are diversified and managed in compliance with all laws and regulations. Management regularly reviews the actual asset allocation and periodically rebalances the investments to targeted allocation when appropriate. The investments are reported at fair value under the Fair Value Measurements and Disclosures accounting guidance.

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies, and target asset allocations by plan. Benefit plan assets are reviewed on a formal basis each quarter by the OVEC-IKEC Qualified Plan Trust Committee.

The investment philosophies for the benefit plans support the allocation of assets to minimize risks and optimize net returns.

Investment strategies include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs, and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style neutral to limit volatility compared to applicable benchmarks.

The target asset allocation for each portfolio is as follows:

Pension Plan Assets	**Target**
Domestic equity	15 %
International and global equity	15
Fixed income	68
Cash	2

VEBA Plan Assets	**Target**
Domestic equity	20 %
International and global equity	20
Fixed income	60

Each benefit plan contains various investment limitations. These limitations are described in the investment policy statement and detailed in customized investment guidelines. These investment guidelines require appropriate portfolio diversification and define security concentration limits. Each investment manager's portfolio is compared to an appropriate diversified benchmark index.

Equity investment limitations:

- No security in excess of 5% of all equities.

Cash equivalents must be less than 10% of each investment manager's equity portfolio.

Individual securities must be less than 15% of each manager's equity portfolio.

No investment in excess of 5% of an outstanding class of any company.

- No securities may be bought or sold on margin or other use of leverage.

Fixed-Income Limitations—As of December 31, 2019, the Pension Plan fixed-income allocation consists of managed accounts composed of U.S. Government, corporate, and municipal obligations. The VEBA benefit plans' fixed-income allocation is composed of a variety of fixed-income securities and mutual funds. Investment limitations for these fixed-income funds are defined by manager prospectus.

Cash Limitations—Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments, including money market mutual funds, certificates of deposit, treasury bills, and other types of investment-grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Projected Pension Plan and Other Postretirement Benefits obligations and funded status as of December 31, 2019 and 2018, are as follows:

	Pension Plan		Other Postretirement Benefits	
	2019	**2018**	**2019**	**2018**
Change in projected benefit obligation:				
Projected benefit obligation—beginning of year	$ 234,099,137	$ 256,019,423	$ 151,305,246	$ 168,487,209
Service cost	6,078,450	7,108,309	3,428,368	4,297,973
Interest cost	10,082,144	9,445,262	6,571,166	6,196,344
Plan participants' contributions		-	1,312,941	1,363,566
Benefits paid	(8,079,496)	(10,240,977)	(6,795,047)	(5,270,543)
Net actuarial loss (gain)	30,255,836	(28,186,233)	21,462	(17,121,066)
Plan amendments (1) (2)		-	3,989,560	(6,648,237)
Settlement (3)	(27,857,703)	-	-	-
Expenses paid from assets	(36,469)	(46,647)	-	-
Projected benefit obligation—end of year	244,541,899	234,099,137	159,833,696	151,305,246
Change in fair value of plan assets:				
Fair value of plan assets—beginning of year	200,204,812	218,769,576	141,118,649	151,290,524
Actual return on plan assets	42,540,447	(14,277,140)	19,940,452	(6,304,997)
Expenses paid from assets	(36,469)	(46,647)	-	-
Employer contributions	5,600,000	6,000,000	13,853	40,099
Plan participants' contributions		-	1,312,941	1,363,566
Benefits paid	(8,079,496)	(10,240,977)	(6,795,047)	(5,270,543)
Settlement	(27,857,703)	-	-	-
Fair value of plan assets—end of year	212,371,591	200,204,812	155,590,848	141,118,649
Underfunded status—end of year	$ (32,170,308)	$ (33,894,325)	$ (4,242,848)	$ (10,186,597)

(1) The $3.9M plan amendment is the result of the change of the long-term retiree cost sharing through retiree contributions for pre-65 retirees from 20% to 12%.

(2) The $6.6M plan amendment is the result of the termination of the active/pre-65 retiree PPO and indemnity plans. All participants in those plans were moved to the CDHP.

(3) The $27.9M settlement is the result of an annuity purchase of about $22.7M for 162 retirees and beneficiaries which was paid on November 25, 2019 and the lump sums payments totaling about $5.2M during 2019.

See Note 1 for information regarding regulatory assets related to the Pension Plan and Other Postretirement Benefits plan.

The accumulated benefit obligation for the Pension Plan was $218,590,886 and $212,367,000 at December 31, 2019 and 2018, respectively.

Components of Net Periodic Benefit Cost—The Companies record the expected cost of Other

Postretirement Benefits over the service period during which such benefits are earned.

Pension expense is recognized as amounts are contributed to the Pension Plan and billed to customers. The accumulated difference between recorded pension expense and the yearly net periodic pension expense, as calculated under generally accepted accounting principles, is billable as a cost of operations under the ICPA when contributed to the pension fund. This accumulated difference has been recorded as a regulatory asset in the accompanying consolidating balance sheets.

	Pension Plan		Other Postretirement Benefits	
	2019	**2018**	**2019**	**2018**
Service cost	$ 6,078,450	$ 7,108,309	$ 3,428,368	$ 4,297,973
Interest cost	10,082,144	9,445,262	6,571,166	6,196,344
Expected return on plan assets	(11,867,776)	(13,034,239)	(7,515,431)	(8,062,728)
Amortization of prior service cost	(416,565)	(416,565)	(3,145,420)	(2,536,062)
Recognized actuarial loss (gain)	1,234,195	1,049,337	-	-
Cost of Settlements	3,570,924	-	-	-
Total benefit cost	$ 8,681,372	$ 4,152,104	$ (661,317)	$ (104,473)
Pension and other postretirement benefits expense recognized in the consolidating statements of income and retained earnings and billed to Sponsoring Companies under the ICPA	$ 5,600,000	$ 6,000,000	$ -	$ -

The following table presents the classification of Pension Plan assets within the fair value hierarchy at December 31, 2019 and 2018:

	Fair Value Measurements at Reporting Date Using			
2019	**Quoted Prices in Active Market for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
Common stock	$ 8,792,346	$ -	$ -	$ 8,792,346
Equity mutual funds	42,776,633	-	-	42,776,633
Index futures	-	230	-	230
Fixed-income securities	-	140,413,999	-	140,413,999
Commodities	-	43	-	43
Cash equivalents	7,154,484	-	-	7,154,484
Subtotal benefit plan assets	$ 58,723,463	$ 140,414,272	$ -	199,137,735
Investments measured at net asset value (NAV)				13,233,857
Total benefit plan assets				$ 212,371,592
2018	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Total**
Common stock	$ 7,138,880	$ -	$ -	$ 7,138,880
Equity mutual funds	35,494,238	-	-	35,494,238
Index futures	-	81	-	81
Fixed-income securities	-	142,452,199	-	142,452,199
Commodities	-	47	-	47
Cash equivalents	3,719,257	-	-	3,719,257
Subtotal benefit plan assets	$ 46,352,375	$ 142,452,327	$ -	188,804,702
Investments measured at net asset value (NAV)				11,400,110
Total benefit plan assets				$ 200,204,812

The following table presents the classification of VEBA and 401(h) account assets within the fair value hierarchy at December 31, 2019 and 2018:

	Fair Value Measurements at Reporting Date Using			
2019	**Quoted Prices in Active Market for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**2019 Total**
Equity mutual funds	$ 54,952,087	$ -	$ -	$ 54,952,087
Fixed-income mutual funds	75,428,176	-	-	75,428,176
Fixed-income securities	-	21,122,393	-	21,122,393
Cash equivalents	1,175,475	-	-	1,175,475
Benefit plan assets	$ 131,555,738	$ 21,122,393	$	152,678,131
Uncleared cash disbursements from benefits paid				(5,468,253)
Investments measured at net asset value (NAV)				8,380,969
Total benefit plan assets				$ 155,590,847
2018	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Total**
Equity mutual funds	$ 46,690,283	$ -	$ -	$ 46,690,283
Fixed-income mutual funds	69,726,689	-	-	69,726,689
Fixed-income securities	-	19,673,412	-	19,673,412
Cash equivalents	1,866,335	-	-	1,866,335
Benefit plan assets	$ 118,283,307	$ 19,673,412	$ -	137,956,719
Uncleared cash disbursements from benefits paid				(3,866,878)
Investments measured at net asset value (NAV)				7,028,808
Total benefit plan assets				$ 141,118,649

Investments that were measured at net asset value (NAV) per share (or its equivalent) as a practical expedient have not been classified in the fair value hierarchy. These investments represent holdings in a single private investment fund that are redeemable at the election of the holder upon no more than 30 days' notice. The values reported above are based on information provided by the fund manager.

Pension Plan and Other Postretirement Benefit Assumptions—Actuarial assumptions used to determine benefit obligations at December 31, 2019 and 2018, were as follows:

	Pension Plan		Other Postretirement Benefits			
	2019	**2018**	**2019**		**2018**	
			Medical	**Life**	**Medical**	**Life**
Discount rate	3.58 %	4.40 %	3.55 %	3.55 %	4.40 %	4.40 %
Rate of compensation increase	3.00	3.00	N/A	3.00	N/A	3.00

Actuarial assumptions used to determine net periodic benefit cost for the years ended December 31, 2019 and 2018, were as follows:

	2019	2018	2019		2018	
			Medical	Life	Medical	Life
Discount rate	4.40 %	3.75 %	4.40 %	4.40 %	3.76 %	3.76 %
Expected long-term return on plan assets	6.00	6.00	5.33	6.00	5.33	6.00
Rate of compensation increase	3.00	3.00	N/A	3.00	N/A	3.00

In selecting the expected long-term rate of return on assets, the Companies considered the average rate of earnings expected on the funds invested to provide for plan benefits. This included considering the Pension Plan and VEBA trusts' asset allocation, and the expected returns likely to be earned over the life of the Pension Plan and the VEBAs.

Assumed health care cost trend rates at December 31, 2019 and 2018, were as follows:

	2019	2018
Health care trend rate assumed for next year—participants under 65	7.00 %	7.00 %
Health care trend rate assumed for next year—participants over 65	7.30	19.40
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)—participants under 65	5.00	5.00
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)—participants over 65	5.00	5.00
Year that the rate reaches the ultimate trend rate	2024	2024

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on total service and interest cost	$ 1,274,727	$ (1,043,944)
Effect on postretirement benefit obligation	19,856,817	(16,262,286)

Pension Plan and Other Postretirement Benefit Assets—The asset allocation for the Pension Plan and VEBA trusts at December 31, 2019 and 2018, by asset category was as follows:

	Pension Plan		VEBA Trusts	
	2019	2018	2019	2018
Asset category:				
Equity securities	31 %	27 %	39 %	37 %
Debt securities	69	73	61	63

Pension Plan and Other Postretirement Benefit Contributions—The Companies expect to contribute $5,800,000 to their Pension Plan and $21,500 to their Other Postretirement Benefits plan in 2020.

Estimated Future Benefit Payments—The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Years Ending December 31	Pension Plan	Other Postretirement Benefits
2020	$ 9,176,543	$ 6,640,020
2021	9,826,112	7,064,850
2022	10,603,824	7,596,021
2023	11,268,181	8,175,889
2024	12,239,883	8,788,750
Five years thereafter	66,774,987	49,888,077

Postemployment Benefits—The Companies follow the accounting guidance in FASB ASC 712, *Compensation—Non-Retirement Postemployment Benefits*, and accrue the estimated cost of benefits provided to former or inactive employees after employment but before retirement. Such benefits include, but are not limited to, salary continuations, supplemental unemployment, severance, disability (including workers' compensation), job training, counseling, and continuation of benefits, such as health care and life insurance coverage. The cost of such benefits and related obligations has been allocated to OVEC and IKEC in the accompanying consolidating financial statements. The allocated amounts represent approximately a 42% and 58% split between OVEC and IKEC, respectively, as of December 31, 2019, and approximately a 59% and 41% split between OVEC and IKEC, respectively, as of December 31, 2018. The liability is offset with a corresponding regulatory asset and represents unrecognized postemployment benefits billable in the future to customers. The accrued cost of such benefits was $5,201,536 and $4,147,956 at December 31, 2019 and 2018, respectively.

Defined Contribution Plan—The Companies have a trustee-defined contribution supplemental pension and savings plan that includes 401(k) features and is available to employees who have met eligibility requirements. The Companies' contributions to the savings plan equal 100% of the first 1% and 50% of the next 5% of employee-participants' pay contributed. In addition, the Companies provide contributions to eligible employees, hired on or after January 1, 2015, of 3% to 5% of pay based on age and service. Benefits to participating employees are based solely upon amounts contributed to the participants' accounts and investment earnings. By its nature, the plan is fully funded at all times. The employer contributions for 2019 and 2018 were $1,966,847 and $2,014,215, respectively.

9. ENVIRONMENTAL MATTERS

Air Regulations

On March 10, 2005, the United States Environmental Protection Agency (the U.S. EPA) issued the Clean Air Interstate Rule (CAIR) that required significant reductions of SO_2 and NO_X emissions from coal-burning power plants. On March 15, 2005, the U.S. EPA also issued the Clean Air Mercury Rule (CAMR) that required significant mercury emission reductions for coal-burning power plants. These emission reductions were required in two phases: 2009 and 2015 for NO_X, 2010 and 2015 for SO_2 and 2010 and 2018 for mercury. Ohio and Indiana subsequently finalized their respective versions of

CAIR and CAMR. In response, the Companies determined that it would be necessary to install flue gas desulfurization (FGD) systems at both plants to comply with these rules. Following completion of the necessary engineering and permitting, construction was started on the FGD systems, and the two Kyger Creek FGD systems were placed into service in 2011 and 2012, while the two Clifty Creek FGD systems were placed into service in 2013.

After the promulgation of CAIR and CAMR, a series of legal challenges to those rules resulted in their replacement with additional rules. CAMR was replaced with a rule referred to as the Mercury and Air Toxics Standards (MATS) rule. The rule became final on April 16, 2012, and the Companies had to demonstrate compliance with MATS emission limits on April 16, 2015. The MATS rule has also undergone legal challenges since it went into effect, and there are a few remaining legal issues pending. The controls the Companies have installed have proven to be adequate to meet the stringent emissions requirements outlined in the MATS rule.

After CAIR was promulgated, legal challenges resulted in that rule being remanded back to the U.S. EPA. The U.S. EPA subsequently promulgated a replacement rule to CAIR called the Cross-State Air Pollution Rule (CSAPR). CSAPR was issued on July 6, 2011, and it was scheduled to go into effect on January 1, 2012. However, a legal challenge of that rule resulted in a stay. The stay was lifted by the D.C. Circuit Court in 2014 and CSAPR, which requires significant NO_X and SO_2 emissions reductions, became effective on January 1, 2015. Further legal challenges of CSAPR resulted in the U.S. Supreme Court remanding portions of the CSAPR rule back to the D.C. Circuit Court for additional review and subsequent action by the U.S. EPA. This resulted in U.S. EPA issuing the CSAPR Update rule which became final on September 7, 2016, and went into effect beginning with the May 1, 2017 to September 30, 2017 ozone season. The CSAPR Update did not replace CSAPR, it only required additional reductions in NO_X emissions from utilities in twenty-two states (including Ohio and Indiana) during the ozone season. The Companies prepared for and implemented a successful compliance strategy for the CSAPR Update rule requirements in the 2017 ozone season. That strategy was standardized to meet future ozone season compliance obligations, and its execution provided for another successful ozone season in 2019. The CSAPR Update Rule has also been subject to extensive litigation, and the D.C. Circuit Court of Appeals issued a decision on September 13, 2019, on one of those legal challenges that remanded portions of this rule back to U.S. EPA to address. The EPA has not yet acted on the remand; however, the Companies are not currently anticipating any potential changes in the rule to address the D.C. Circuit Court remand that would materially impact our current compliance strategy or change future operations.

As a result of the installation and effective operation of the FGD systems and the SCR systems at each plant, management did not need to purchase additional annual SO_2 allowances, annual NO_X allowances or ozone season NO_X allowances in 2019 to cover actual emissions. The Companies also maintain a bank of allowances for all three programs as a hedge to cover future emissions in the event of any short-term operating events or other external factors. Depending on a variety of operational and economic factors, management may elect to consume a portion of these banked allowances and/or strategically purchase additional CSAPR annual and ozone season allowances in 2020 and beyond for compliance with the CSAPR and CSAPR Update rules.

With all FGD systems fully operational, the Companies continue to expect to have adequate SO_2 allowances available every year without having to rely on market purchases to comply with the CSAPR rules in their current form. Given the success of the Companies' NO_X ozone season compliance strategy, the purchase of additional NO_X allowances is less likely in the short term as well; however, the Companies did implement changes in unit dispatch criteria for Clifty Creek Unit 6 during the 2017 and subsequent ozone seasons and are continuing to evaluate the need for additional NO_X controls for this unit to provide additional flexibility in operating this unit in the event future NO_X regulations place additional emission constraints on the utility industry.

CCR Rule

In 2010, the U.S. EPA published a proposed rule to regulate the disposal and beneficial reuse of coal combustion residuals (CCRs), including fly ash and boiler slag generated at coal-fired electric generating units as well as FGD gypsum generated at some coal-fired plants. The proposed rule contained two alternative proposals. One proposal would impose federal hazardous waste disposal and management standards on these materials and another would allow states to retain primary authority to regulate the beneficial reuse and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and existing unlined surface impoundments.

Various environmental organizations and industry groups filed a petition seeking to establish deadlines for a final rule. To comply with a court-ordered deadline, the U.S. EPA issued a prepublication copy of its final rule in December 2014. The rule was published in the Federal Register in April 2015 and became effective in October 2015.

In the final rule, the U.S. EPA elected to regulate CCR as a nonhazardous solid waste and issued new minimum federal solid waste management standards. The rule applies to new and existing active CCR landfills and CCR surface impoundments at operating electric utility or independent power production facilities. The rule imposes new and additional construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria, and additional groundwater monitoring requirements. The rule is self-implementing and currently does not require state action. As a result of this self-implementing feature, the rule contains extensive recordkeeping, notice, and Internet posting requirements.

The Companies have been systematically implementing the applicable provisions of the CCR rule. The Companies have completed all compliance obligations associated with the rule to date and are continuing to evaluate what, if any, impacts groundwater quality will have on the South Fly Ash Pond and landfill at Kyger Creek and the West Boiler Slag Pond and landfill at Clifty Creek. To date, these four CCR units continue to meet the groundwater monitoring standards of the CCR Rule. The Companies have been evaluating potential impacts to groundwater quality near the boiler slag pond at Kyger Creek and the landfill runoff collection pond at Clifty Creek as required by the CCR Rule. The Companies have determined that statistically significant increases (SSIs) in certain groundwater parameters are present at the two identified locations, and additional steps as defined by the CCR rule were taken. The evaluation of whether an SSI exists is a required component of the groundwater monitoring conditions of the CCR rule. A determination that an SSI appears to be present requires additional evaluation to be undertaken by the facility to determine if there are alternative sources that are influencing groundwater quality and to evaluate the extent of the groundwater quality impact. Concurrently, a facility must continue to evaluate groundwater quality as required by the CCR rule, and determine what potential corrective actions are feasible to address the SSIs. The Companies conducted Alternative Source Demonstrations (ASD) to determine if groundwater was being influenced from sources other than the CCR unit. The ASDs were unable to definitively prove that alternative sources were directly influencing groundwater quality. As a result, the Companies worked with their Qualified Professional Engineer (QPE) to determine what corrective actions were feasible for each CCR unit, and then held a public meeting to discuss these options with the public prior to selecting a remedy. The Companies continue to work through the compliance requirements of the CCR Rule and remain in compliance.

Since the initial rollout of the CCR rules in 2015, several legal, legislative and regulatory events impacting the scope, applicability and future CCR compliance obligations and timelines have also taken place. Final actions include federal legislation (i.e., the WIIN Act) that provides a pathway for states to seek approval for administering and enforcing the federal CCR program, U.S. EPA's issuance of a Phase I, Part I revision to the CCR rules on March 1, 2018, and the D.C. Circuit Court's August 21, 2018, ruling vacating and remanding portions of the CCR rule. In addition, the U.S. EPA announced plans to issue additional revisions to the CCR rule, some of which would also directly address the D.C. Circuit Court's issues raised in its August 21, 2018, decision. Other proposed revisions to the 2015 CCR rules that the U.S. EPA is currently undertaking will address outstanding issues previously identified by the agency and the Court. Two draft CCR rules entitled Part A and Part B, are in the public notice phase and are expected to be issued in final form later in 2020. Part A proposes a significant revision to the 2015 CCR rule requiring all impoundments that do not meet the liner requirements outlined in the 2015 CCR rule to cease receiving CCR material and initiate closure by August 31, 2020, regardless of their overall compliance status. If that date is not technically feasible, an alternate date to cease receiving CCR material and initiate closure can be secured from U.S. EPA through a proposed extension request process. The surface impoundments at Kyger Creek and Clifty Creek do not meet the liner design requirements required under the 2015 CCR rule. As a result, the Companies have begun an engineering evaluation to determine a technically feasible timeline for discontinuing placement of CCR materials in these impoundments and the initiation of closure consistent with the draft rule. Subsequently, the Companies intend to submit a technical justification document to U.S. EPA that demonstrates why additional time is needed to cease placement of CCR in the surface impoundments and initiate closure. The Companies anticipate U.S. EPA will approve the alternative schedule at this time. Separately, the proposed Part B revisions to the 2015 CCR rule outline the development of a federal permitting program to regulate and enforce the CCR rule at all applicable facilities consistent with the Congressional mandate outlined in the WIIN Act. This federal permit program would replace the current enforcement mechanism of a self-implementing rule enforced through citizen suits and place it back with U.S. EPA or any state regulatory that receives primacy to implement the CCR permitting within their respective state. The Companies are actively monitoring these developments and adapting their CCR compliance program to ensure compliance obligations and timelines are adjusted accordingly. Changes in regulations or in the Companies' strategies for mitigating the impact of coal combustion residuals could potentially result in material increases to the asset retirement obligations.

In February 2014, the U.S. EPA completed a risk evaluation of the beneficial uses of coal fly ash in concrete and FGD gypsum in wallboard and concluded that the U.S. EPA supports these beneficial uses. Currently, approximately 60 percent of the coal ash and other residual products from our generating facilities are reused in the production of cement and wallboard, as soil amendments, as abrasives or road treatment materials, and for other beneficial uses.

NAAQS Compliance for SO_2

On June 22, 2010, the U.S. EPA revised the Clean Air Act by developing and publishing a new one-hour SO_2 NAAQS of 75 parts per billion, which replaced the previously existing 24-hour and annual standards, and became effective on August 23, 2010. States with areas failing to meet the standard were required to develop state implemented plans to expeditiously attain and maintain the standard.

On August 15, 2013, the U.S. EPA published its initial non-attainment area designations for the new one-hour SO_2, which did not include the areas around Kyger Creek or Clifty Creek. However, the amended rule does establish that at a minimum, sources that emit 2,000 tons SO_2 or more per year be characterized by their respective states using either modeling of actual source emissions or through appropriately sited ambient air quality monitors.

In addition, U.S. EPA entered into a settle agreement with Sierra Club/NRDC in the U.S. District Court for the Northern District of California requiring U.S. EPA to take certain actions, including completing area designation by July 2, 2016, for areas with either monitored violations based on 2013-15 air quality monitoring or sources not announced for retirement that emitted more than 16,000 tons SO_2 or more than 2,600 tons with a 0.45 SO_2/mmBtu emission rate in 2012.

Both Kyger Creek and Clifty Creek directly or indirectly triggered one of the criteria and have been evaluated by the respective state regulatory agencies through modeling. The modeling results showed Clifty Creek could meet the new one-hour SO_2 limit using their current scrubber systems without any additional investment or modifications. Kyger Creek's modeling data was rejected by U.S. EPA as inconclusive in 2016. As a result, U.S. EPA required Kyger Creek install an SO_2 monitoring network around the plant and monitor ambient air quality beginning on January 1, 2017. Based on the first three years of data from that network, Ohio EPA will be preparing an updated petition to U.S. EPA requesting that the area in the county surrounding the plant be designated in attainment of the one-hour standard. Finally, on February 26, 2019, the U.S. EPA issued a final decision that it is retaining the existing primary SO_2 NAAQS at 75 parts per billion for the next five-year NAAQS review cycle. Given this decision, combined with current scrubber performance, the Companies expect to avoid more restrictive permit limits relative to its SO_2 emissions or the need for additional capital investment in major scrubber upgrades or modifications.

Steam Electric ELGs

On September 30, 2015, the U.S. EPA signed a new final rule governing Effluent Limitations Guidelines (ELGs) for the wastewater discharges from steam electric power generating plants. The rule, which was formally published in the Federal Register on November 3, 2015, impacted future wastewater discharges from both the Kyger Creek and Clifty Creek Stations.

The rule was intended to require the Companies to modify the way they handle a number of wastewater processes at both power plants. Specifically, the new ELG standards were going to affect the following wastewater processes in three ways listed below; however, in April 2017, the U.S. EPA issued an administrative stay on the ELG rule; and then in June 2017, the U.S. EPA issued a separate rulemaking staying the compliance deadlines for portions of the ELG rule applicable to bottom ash sluice water and to FGD wastewater discharges. The U.S. EPA has been working to revise the rule to evaluate what constitutes "best available technology" for these two wastewater discharges and issue an updated rule by no later than the fall of 2020. While the revised rule is not yet final, the Companies' understanding of what the original impacts and updated impacts to each wastewater discharge are highlighted below:

1. Kyger Creek will need to convert to dry fly ash handling by no later than December 31, 2023. The U.S. EPA stay on portions of the ELG rule does not impact the need to convert Kyger Creek Station to dry fly ash handling or the associated timeline. The Clifty Creek Station already has a dry fly ash handling system in place, so this provision of the rule will not impact Clifty Creek's operations.

The new ELG rules originally prohibited the discharge of bottom ash sluice water from boiler slag/bottom ash wastewater treatment systems. For Clifty Creek and Kyger Creek, this will likely result in the conversion of each plant's boiler slag pond to a closed-loop sluicing system for boiler slag. The Companies conducted a Phase I engineering study in 2016 to determine options and costs associated with retrofitting the plants' boiler slag treatment systems but postponed the study until more information was available from U.S. EPA on the technologies being considered in the revised rule. After reviewing the new draft rule, the Companies resumed the engineering study needed to formulate an overall compliance strategy based on this updated information. This study includes a further evaluation of technologies or retrofits capable of complying with the requirements of the revised rule, which include preliminary engineering, design, and schedule development that were initiated late in 2019. The results of that evaluation are expected to be available in the second quarter of 2020.

The new ELG rules originally established new internal limitations for the FGD system wastewater discharges. Specifically, there were to be new internal limits for arsenic, mercury, selenium, and nitrate/nitrite nitrogen from the FGD chlorides purge stream wastewater treatment plant at each plant. For both Clifty Creek and Kyger Creek Stations, the Companies were expecting to be able to meet the mercury and arsenic limitations with the current wastewater treatment technology; however, the Companies were expecting to add some form of biological (or equivalent nonbiological) treatment system on the back end of each Station's existing FGD wastewater treatment plant to meet the new nitrate/nitrite nitrogen and selenium limitations. Installation of new controls to meet the final effluent limitations contained in the revised rule are currently on hold while the Companies await further regulatory action from the U.S. EPA that will determine what the new limits for each of these constituents will be in the final ELG rule, which is expected late fall 2020. Once those final effluent limits are established, the Companies will resume evaluation of the appropriate technology, design, and schedule to achieve compliance with the new requirements. Based on the Companies' review of the draft revised ELG rule, the compliance deadline for FGD wastewater has been moved to compliance with the updated requirements no later than December 31, 2025.

Any new ELG limits will be implemented through each Station's wastewater discharge permit, which is typically renewed on a five-year basis. The final compliance dates are expected to be facility-specific and negotiated with the Companies' state permit agencies based on the time needed to plan, secure funding, design, procure, and install necessary control technologies once the new rulemaking has been completed. The Companies will continue to monitor EPA regulatory actions on this rule and will respond as necessary.

316(b) Compliance

The 316(b) rule was published as a final rule in the Federal Register on August 15, 2014, and impacts facilities that use cooling water intake structures designed to withdraw at least 2 million gallons per day from waters of the U.S., and those facilities who also have an NPDES permit. The rule requires such facilities choose one of seven options specified by the rule to reduce impingement to fish and other aquatic organisms. Additionally, facilities that withdraw 125 million gallons or more per day must conduct entrainment studies to assist state permitting authorities in determining what site-specific controls are required to reduce the number of aquatic organisms entrained by each respective cooling water system.

The Companies have completed the required two-year fish entrainment studies and filed the reports with the respective state regulatory agencies consistent with regulatory requirements under 40 CFR Section 122.21(r).

The timeline for determining if retrofits may be required to the cooling water systems at either Clifty Creek or Kyger Creek, as well as the type of retrofit required, will be negotiated with each state regulatory agency during future NPDES Permit renewals consistent with state regulatory obligations under 40 CFR Section 125.98(f).

The environmental rules and regulations discussed throughout the Environmental Matters footnote could require additional capital expenditures or maintenance expenses in future periods.

10. FAIR VALUE MEASUREMENTS

The accounting guidance for Financial Instruments requires disclosure of the fair value of certain financial instruments. The estimates of fair value under this guidance require the application of broad assumptions and estimates. Accordingly, any actual exchange of such financial instruments could occur at values significantly different from the amounts disclosed.

OVEC utilizes its trustee's external pricing service in its estimate of the fair value of the underlying investments held in the benefit plan trusts and investment portfolios. The Companies' management reviews and validates the prices utilized by the trustee to determine fair value. Equities and fixed-income securities are classified as Level 1 holdings if they are actively traded on exchanges. In addition, mutual funds are classified as Level 1 holdings because they are actively traded at quoted market prices. Certain fixed-income securities do not trade on an exchange and do not have an official closing price. Pricing vendors calculate bond valuations using financial models and matrices. Fixed-income securities are typically classified as Level 2 holdings because their valuation inputs are based on observable market data. Observable inputs used for valuing fixed-income securities are benchmark yields, reported trades, broker/dealer quotes, issuer spreads, bids, offers, and economic events. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments.

As of December 31, 2019 and 2018, the Companies held certain assets that are required to be measured at fair value on a recurring basis. These consist of investments recorded within long-term investments. The investments consist of money market mutual funds, equity mutual funds, and fixed-income municipal securities. Changes in the observed trading prices and liquidity of money market funds are monitored as additional support for determining fair value, and unrealized gains and losses are recorded in earnings.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Furthermore, while the Companies believe their valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

As cash and cash equivalents, current receivables, current payables, and line of credit borrowings are all short-term in nature, their carrying amounts approximate fair value.

Long-Term Investments—Assets measured at fair value on a recurring basis at December 31, 2019 and 2018, were as follows:

	Fair Value Measurements at Reporting Date Using		
2019	**Quoted Prices in Active Market for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Equity mutual funds	$ 99,982,734	$ -	$ -
Fixed-income mutual funds	37,002,850	-	-
Fixed-income municipal securities		101,374,099	-
Cash equivalents	2,379,596	-	-
Total fair value	$ 139,365,180	$ 101,374,099	$ -
2018	**(Level 1)**	**(Level 2)**	**(Level 3)**
Equity mutual funds	$ 64,095,224	$ -	$ -
Fixed-income mutual funds	22,186,437	-	-
Fixed-income municipal securities	-	93,085,183	-
Cash equivalents	1,904,689	-	-
Total fair value	$ 88,186,350	$ 93,085,183	$ -

Long-Term Debt—The fair values of the senior notes and fixed-rate bonds were estimated using discounted cash flow analyses based on current incremental borrowing rates for similar types of borrowing arrangements. These fair values are not reflected in the balance sheets. The fair values and recorded values of the senior notes and fixed- and variable-rate bonds as of December 31, 2019 and 2018, are as follows:

	2019		**2018**	
	Fair Value	**Recorded Value**	**Fair Value**	**Recorded Value**
Total	1,390,779,759	1,275,148,664	1,398,244,690	1,329,819,085

11. LEASES

OVEC has various operating leases for the use of other property and equipment.

On January 1, 2019, the Companies adopted ASC 842, “Leases” which, among other changes, requires the Companies to record liabilities classified as operating leases on the balance sheet along with a corresponding right-of-use asset. Results for reporting periods beginning January 1, 2019, are presented under Topic 842, while prior period amounts are not adjusted and continue to be reported in accordance with historic accounting under Topic 840. The Companies elected the package of practical expedients available for expired or existing contracts, which allowed them to carryforward their historical assessments of whether contracts are or contain leases, lease classification tests and treatment of initial direct costs. Further, the Companies elected to not separate lease components from non-lease components for all fixed payments, and excluded variable lease payments in the measurement of right-of-use assets and lease obligations.

Upon adoption of ASC 842, the impact was a $22,000 increase in ROU assets and operating lease obligations. These adjustments are the result of assigning a right-of-use asset and related lease liability to the Companies operating leases. There were no cumulative effect adjustments to opening retained earnings, and adoption of the lease standard had no impact to cash from or used in operating, financing, or investing activities on the cash flow statement.

The Companies determine whether an arrangement is, or includes, a lease at contract inception. Leases with an initial term of 12 months or less are not recognized on the balance sheet. The Companies recognize lease expense for these leases on a straight-line basis over the lease term.

Operating lease right-of-use assets and liabilities are recognized at commencement date and initially measured based on the present value of lease payments over the defined lease term.

The leases typically do not provide an implicit rate; therefore, the Companies use the estimated incremental borrowing rate at the time of lease commencement to discount the present value of lease payments. In order to apply the incremental borrowing rate, a portfolio approach with a collateralized rate is utilized. Assets were grouped based on similar lease terms and economic environments in a manner whereby the Companies reasonably expect that the application is not expected to differ materially from a lease-by-lease approach.

The Companies have operating and finance leases for the use of vehicles, property, and equipment. The leases have remaining terms of 1 year to 7 years. The components of lease expense were as follows:

Year Ending December 31,	**2019**
Operating lease cost	$ 15,095
Finance lease cost:	
Amortization of leased assets	$ 258,411
Interest on lease liabilities	61,547
Total finance lease cost	$ 319,958

Supplemental cash flow information related to leases was as follows:

Operating cash flows from operating leases	$15,095
Operating cash from finance leases	55,793
Financing cash flows from finance leases	156,130
Weighted average remaining lease term:	
Operating leases	< 1 year
Finance leases	4 years
Weighted average discount rate:	
Operating leases	3.8 %
Finance leases	8.1 %

The amount of operating lease ROU assets and liabilities is $7,431 and $0 as of December 31, 2019 and 2018, respectively.

The amount in property under finance leases is $1,545,051 and $1,156,718 with accumulated depreciation of $669,164 and $464,194 as of December 31, 2019 and 2018, respectively.

Future cash flows of operating leases, and maturities of financing lease liabilities are as follows:

Years Ending December 31	**Operating**	**Finance**
2020	$ 7,512	$ 291,782
2021	-	221,997
2022	-	151,065
2023	-	89,223
2024	-	55,121
Thereafter	-	105,649
Total future minimum lease payments	$ 7,512	914,837
Less estimated interest element		168,135
Estimated present value of future minimum lease payments		$ 746,702

12. COMMITMENTS AND CONTINGENCIES

The Companies are party to or may be affected by various matters under litigation. Management believes that the ultimate outcome of these matters will not have a significant adverse effect on either the Companies' future results of operation or financial position.

On March 31, 2018, FirstEnergy Solutions Corp. (FES), one of the Sponsoring Companies under the ICPA, filed for Chapter 11 bankruptcy protection under the United States Bankruptcy Code in the United States Bankruptcy Court for the Northern District of Ohio (the "Bankruptcy Court"). OVEC made a preemptive filing on March 26, 2018, at the Federal Energy Regulatory Commission (FERC) requesting either (i) an order finding that FES's anticipated rejection of the ICPA would constitute a violation of that agreement's terms and would not satisfy the Federal Power Act's "public interest" standard, or, (ii) an order declaring that FERC has exclusive jurisdiction over the proposed rejection of the ICPA (the "FERC Action"). On April 1, 2018, FES filed in the Bankruptcy Court a motion to reject the ICPA and separately obtained an order temporarily enjoining the FERC Action. On May 11, 2018, the Bankruptcy Court granted a preliminary injunction enjoining FERC from reviewing FES's requested rejection of the ICPA under the public interest standard. FERC subsequently filed an appeal of this decision with the United States Court of Appeals for the Sixth Circuit (the "Injunction Appeal"), which OVEC joined as an intervenor. On July 31, 2018, the Bankruptcy Court granted FES's motion to reject the ICPA using the "business judgement" standard used to evaluate contract rejection under the Bankruptcy Code (the "Rejection Order"). Per the ICPA, upon rejection, OVEC made available to all other Sponsoring Companies FES's entitlement to available energy under the ICPA. OVEC appealed the Rejection Order to the Sixth Circuit (the "Rejection Appeal"). The Rejection Appeal was ultimately consolidated with the Injunction Appeal (together as consolidated, the "Sixth Circuit Rejection Appeal"). On December 12, 2019, the U.S. Court of Appeals for Sixth Circuit ruled on the Sixth Circuit Rejection Appeal by (1) affirming the Bankruptcy Court's jurisdiction over the rejection of the ICPA and (2) finding that the Bankruptcy Court should have considered the public interest in the standard for rejection and remanding to the Bankruptcy Court for further consideration under a heightened standard, after giving FERC a reasonable opportunity to weigh in. OVEC filed a petition for rehearing "en banc," and on March 13, 2020, the Sixth Circuit denied the petition.

On July 31, 2019, OVEC and FES entered into a stipulation with respect to OVEC's objection to confirmation of the FES plan of reorganization, stipulating that FES (a) would not seek to dismiss OVEC's Sixth Circuit appeal, or, if applicable, OVEC's appeal of an order with respect to an objection by OVEC to confirmation of the plan arising under section 1129(a)(6) of the Bankruptcy Code or oppose further review by the United States Supreme Court, on the grounds of mootness. OVEC objected to confirmation of the FES plan under section 1129(a)(6) of the Bankruptcy Code, which requires any governmental regulatory commission with jurisdiction, after confirmation of the plan, over the rates of a debtor to approve any rate change provided for in the plan, or that such rate change is expressly conditioned on such regulatory approval. OVEC's objection was overruled at the confirmation hearing on August 20th and 21st. The FES plan of reorganization was confirmed on October 16, 2019. On October 29, 2019, OVEC moved to certify a direct appeal of the Bankruptcy Court's confirmation order to the Sixth Circuit. On November 27, 2019, the Bankruptcy Court granted OVEC's motion to certify the confirmation order for direct appeal to the Sixth Circuit. On March 24, 2020, the Sixth Circuit granted OVEC's petition for direct appeal of the confirmation order.

On October 14, 2018, OVEC filed with the Bankruptcy Court its rejection damages claim of approximately $540 million against FES. The amount of OVEC's rejection damages claim has not been litigated at this time. Until the outcome of the Sixth Circuit Appeal and, potentially, a subsequent proceeding at FERC, it is undetermined whether FES will ultimately be permitted to reject its interest in the ICPA. FES's share of obligations, in each case under the ICPA, is approximately 5%. However, the Companies currently have access to the credit markets to fund ongoing liquidity needs, and the Sponsoring Companies remain obligated to fund debt service payments when due. The Companies accounts receivables as of December 31, 2019, on the consolidating balance sheets include receivables for FES's share of the Sponsor billings from March 2018 through December 31, 2019, which amounts to $38.5 million at December 31, 2019.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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	7,640	
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant		
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	7,640	
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,345,194	
9	(311) Structures and Improvements	396,290,437	221,317
10	(312) Boiler Plant Equipment	831,404,421	3,613,952
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	64,499,763	150,632
13	(315) Accessory Electric Equipment	43,946,534	56,105
14	(316) Misc. Power Plant Equipment	28,613,255	
15	(317) Asset Retirement Costs for Steam Production		
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,366,099,604	4,042,006
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		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
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)		
36	D. Other Production Plant		
37	(340) Land and Land Rights		
38	(341) Structures and Improvements		
39	(342) Fuel Holders, Products, and Accessories		
40	(343) Prime Movers		
41	(344) Generators		
42	(345) Accessory Electric Equipment		
43	(346) Misc. Power Plant Equipment		
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)		
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,366,099,604	4,042,006

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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
			7,640		2
					3
					4
			7,640		5
					6
					7
			1,345,194		8
107,780			396,403,974		9
240,234			834,778,139		10
					11
77,630			64,572,765		12
622,479			43,380,160		13
			28,613,255		14
					15
1,048,123			1,369,093,487		16
					17
					18
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1,048,123			1,369,093,487		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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	176,939	
49	(352) Structures and Improvements	1,969,812	
50	(353) Station Equipment	22,634,083	654,622
51	(354) Towers and Fixtures	2,483,460	
52	(355) Poles and Fixtures		
53	(356) Overhead Conductors and Devices	2,320,331	
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)	29,584,625	654,622
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights		
61	(361) Structures and Improvements		
62	(362) Station Equipment		
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures		
65	(365) Overhead Conductors and Devices		
66	(366) Underground Conduit		
67	(367) Underground Conductors and Devices		
68	(368) Line Transformers		
69	(369) Services		
70	(370) Meters		
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems		
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)		
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	4,946	
87	(390) Structures and Improvements	14,633	
88	(391) Office Furniture and Equipment	22,380	
89	(392) Transportation Equipment		
90	(393) Stores Equipment	396	
91	(394) Tools, Shop and Garage Equipment		
92	(395) Laboratory Equipment	910	
93	(396) Power Operated Equipment	629	
94	(397) Communication Equipment	967,488	
95	(398) Miscellaneous Equipment		
96	SUBTOTAL (Enter Total of lines 86 thru 95)	1,011,382	
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)	1,011,382	
100	TOTAL (Accounts 101 and 106)	1,396,703,251	4,696,628
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)	1,396,703,251	4,696,628

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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
			176,939		48
			1,969,812		49
246,855			23,041,850		50
			2,483,460		51
					52
			2,320,331		53
					54
					55
					56
					57
246,855			29,992,392		58
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			4,946		86
			14,633		87
			22,380		88
					89
			396		90
					91
			910		92
			629		93
			967,488		94
					95
			1,011,382		96
					97
					98
			1,011,382		99
1,294,978			1,400,104,901		100
					101
					102
					103
1,294,978			1,400,104,901		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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	Station 1 Barge Unloader	1,673,699
2	U#1-6 FGD & Simulation Ovation Controls	842,756
3		
4		
5		
6	Projects Less Than $100,000	5,175
7		
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41		
42		
43	TOTAL	2,521,630

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	747,809,746	747,809,746		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	42,456,518	42,456,518		
4	(403.1) Depreciation Expense for Asset Retirement Costs	2,818,840	2,818,840		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	45,275,358	45,275,358		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	2,919,858	2,919,858		
13	Cost of Removal	6,403	6,403		
14	Salvage (Credit)	56,987	56,987		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	2,869,274	2,869,274		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17	Change in RWIP, Deferred Depreciation	-8,689,694	-8,689,694		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	781,526,136	781,526,136		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	751,112,012	751,112,012		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission	29,407,688	29,407,688		
26	Distribution				
27	Regional Transmission and Market Operation				
28	General	1,006,436	1,006,436		
29	TOTAL (Enter Total of lines 20 thru 28)	781,526,136	781,526,136		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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)	16,360,163	33,957,576	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	16,223,474	15,429,862	Electric
8	Transmission Plant (Estimated)			Electric
9	Distribution Plant (Estimated)			
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	16,223,474	15,429,862	
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)	5,199		Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	32,588,836	49,387,438	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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)	2020 No. (d)	2020 Amt. (e)
1	Balance-Beginning of Year	237,876.00		50,576.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	50,576.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	4,191.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	284,261.00		50,576.00	
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.

2021		2022		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
50,576.00		50,576.00				389,604.00		1
								2
								3
						50,576.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						4,191.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
50,576.00		50,576.00				435,989.00		29
								30
								31
								32
								33
								34
								35
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								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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)	2020 No. (d)	2020 Amt. (e)
1	Balance-Beginning of Year	4,197.00		8,581.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	8,581.00			
5	Returned by EPA	193.00			
6					
7					
8	Purchases/Transfers:				
9	Transfer to				
10	Kyger Creek	-1,248.00			
11					
12	Transfer from				
13	Kyger Creek		3,536		
14					
15	Total	-1,248.00	3,536		
16					
17	Relinquished During Year:				
18	Charges to Account 509	6,571.00	3,536		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	5,152.00		8,581.00	
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				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2021		2022		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
		8,581.00				21,359.00		1
								2
								3
						8,581.00		4
						193.00		5
								6
								7
								8
								9
						-1,248.00		10
								11
								12
							3,536	13
								14
						-1,248.00	3,536	15
								16
								17
						6,571.00	3,536	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
		8,581.00				22,314.00		29
								30
								31
								32
								33
								34
								35
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								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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	Unrecognized Pension Expense	14,659,296		228	488,275	14,171,021
2	per SFAS 87					
3						
4	Unrecognized Postemployment Benefit Exp	1,683,544	1,336,457			3,020,001
5	per SFAS 112					
6						
7						
8						
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13						
14						
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32						
33						
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35						
36						
37						
38						
39						
40						
41						
42						
43						
44	**TOTAL :**	16,342,840	1,336,457		488,275	17,191,022

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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	Accumulated expenses of					
2	iKEC perfomorming maintenance					
3	work for an outside party	251		158	251	
4						
5						
6						
7						
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42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	251				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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	Future FIT Benefits, per SFAS 109	9,967,222	15,403,970
3	Tax on Deferred Billings		
4	Valuation Allowance	-188,481	-5,374,120
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	9,778,741	10,029,850
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	9,778,741	10,029,850

Notes

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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)	
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	
28	Show Computation of Tax:	
29		
30		
31		
32		
33		
34	A consolidated federal income tax return is filed with the parent	
35	company, Ohio Valley Electric Corporation.	
36		
37		
38		
39		
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43		
44		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	FEDERAL:					
2	FICA	191,978		1,958,598	1,952,954	
3	Unemployment	11,077		12,132	12,348	
4	SUBTOTAL	203,055		1,970,730	1,965,302	
5						
6	INDIANA:					
7	Unemployment	9,231		13,737	13,917	
8	SUBTOTAL	9,231		13,737	13,917	
9						
10	Property Tax					
11	2018	3,336,000		142,870	3,478,870	
12	2019			3,490,000	3,490,000	
13	SUBTOTAL	3,336,000		3,632,870	6,968,870	
14						
15						
16						
17						
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36						
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38						
39						
40						
41	TOTAL	3,548,286		5,617,337	8,948,089	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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 (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
197,622		1,767,642			190,956	2
10,861		10,910			1,222	3
208,483		1,778,552			192,178	4
						5
						6
9,051		12,386			1,351	7
9,051		12,386			1,351	8
						9
						10
		142,870				11
3,490,000		3,490,000				12
3,490,000		3,632,870				13
						14
						15
						16
						17
						18
						19
						20
						21
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						29
						30
						31
						32
						33
						34
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						36
						37
						38
						39
						40
3,707,534		5,423,808			193,529	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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	Deferred Credit - Cash Receipts	-178				-178
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						
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33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	-178				-178

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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	Accumulated Deferred FIT-Pensi			
4	Accumulated Deferred FIT-Other	4,315,990		
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	4,315,990		
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)	4,315,990		
20	Classification of TOTAL			
21	Federal Income Tax			
22	State Income Tax			
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
				190	937,083	5,253,073	4
							5
							6
							7
							8
					937,083	5,253,073	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
					937,083	5,253,073	19
							20
							21
							22
							23

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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	Def Credit - Other Postretirment Benefits	17,507,866			2,853,844	20,361,710
2						
3	Demolition & Decommission	2,818,822			5,842,809	8,661,631
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	20,326,688			8,696,653	29,023,341

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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		
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)		
5	Large (or Ind.) (See Instr. 4)		
6	(444) Public Street and Highway Lighting		
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers		
11	(447) Sales for Resale	264,778,887	258,738,544
12	TOTAL Sales of Electricity	264,778,887	258,738,544
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	264,778,887	258,738,544
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues		
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property		
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues		
22	(456.1) Revenues from Transmission of Electricity of Others		
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues		
27	TOTAL Electric Operating Revenues	264,778,887	258,738,544

Name of Respondent Indiana-Kentucky Electric Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/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
				3
				4
				5
				6
				7
				8
				9
				10
5,722,980	6,311,468	1	1	11
5,722,980	6,311,468	1	1	12
				13
5,722,980	6,311,468	1	1	14

Line 12, column (b) includes $ 0 of unbilled revenues.
Line 12, column (d) includes 0 MWH relating to unbilled revenues

Schedule Page: 310 Line No.: 4 Column: a

All power generated by Indiana-Kentucky Electric Corporation is purchased by Ohio Valley Electric Corporation, the Parent Company, under the Power Agreement between the two companies dated July 10, 1953.

Schedule Page: 310 Line No.: 4 Column: b

Power sold pursuant to a Power Agreement between Ohio Valley Electric Corporation (OVEC) and Indiana-Kentucky Electric Corporation (IKEC), which provides that all power generated by IKEC, and energy associated therewith, less transmission losses, shall be delivered to OVEC.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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)	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						
2						
3						
4	Ohio Valley Electric Corporation	OS	FPC 1-B	NA	NA	NA
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
					3
5,722,980	117,655,312	147,123,575		264,778,887	4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
5,722,980	117,655,312	147,123,575	0	264,778,887	
5,722,980	**117,655,312**	**147,123,575**	**0**	**264,778,887**	

Schedule Page: 310 Line No.: 4 Column: a

All power generated by Indiana-Kentucky Electric Corporation is purchased by Ohio Valley Electric Corporation, the Parent Company, under the Power Agreement between the two companies dated July 10, 1953.

Schedule Page: 310 Line No.: 4 Column: b

Power sold pursuant to a Power Agreement between Ohio Valley Electric Corporation (OVEC) and Indiana-Kentucky Electric Corporation (IKEC), which provides that all power generated by IKEC, and energy associated therewith, less transmission losses, shall be delivered to OVEC.

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	4,757,949	4,302,761
5	(501) Fuel	141,269,747	145,267,890
6	(502) Steam Expenses	5,287,466	5,625,739
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	3,892,922	4,426,803
10	(506) Miscellaneous Steam Power Expenses	10,460,411	10,787,581
11	(507) Rents		
12	(509) Allowances	3,536	34,017
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	165,672,031	170,444,791
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	4,375,723	4,549,580
16	(511) Maintenance of Structures	2,705,356	3,169,297
17	(512) Maintenance of Boiler Plant	27,916,326	27,370,021
18	(513) Maintenance of Electric Plant	7,844,052	7,142,955
19	(514) Maintenance of Miscellaneous Steam Plant	799,731	859,101
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	43,641,188	43,090,954
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	209,313,219	213,535,745
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		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

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Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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		
63	(547) Fuel		
64	(548) Generation Expenses		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)		
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)		
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)		
75	E. Other Power Supply Expenses		
76	(555) Purchased Power		
77	(556) System Control and Load Dispatching		
78	(557) Other Expenses		
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)		
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	209,313,219	213,535,745
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering		
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		
89	(561.5) Reliability, Planning and Standards Development		
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	157,478	10,792
94	(563) Overhead Lines Expenses	175,143	130,161
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others		
97	(566) Miscellaneous Transmission Expenses	9,509	32,945
98	(567) Rents		
99	TOTAL Operation (Enter Total of lines 83 thru 98)	342,130	173,898
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures	29,862	14,450
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	161,825	221,482
108	(571) Maintenance of Overhead Lines		2,478
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	8,325	5,481
111	TOTAL Maintenance (Total of lines 101 thru 110)	200,012	243,891
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	542,142	417,789

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Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
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		
135	(581) Load Dispatching		
136	(582) Station Expenses		
137	(583) Overhead Line Expenses		
138	(584) Underground Line Expenses		
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses		
141	(587) Customer Installations Expenses		
142	(588) Miscellaneous Expenses		
143	(589) Rents		
144	TOTAL Operation (Enter Total of lines 134 thru 143)		
145	Maintenance		
146	(590) Maintenance Supervision and Engineering		
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment		
149	(593) Maintenance of Overhead Lines		
150	(594) Maintenance of Underground Lines		
151	(595) Maintenance of Line Transformers		
152	(596) Maintenance of Street Lighting and Signal Systems		
153	(597) Maintenance of Meters		
154	(598) Maintenance of Miscellaneous Distribution Plant		
155	TOTAL Maintenance (Total of lines 146 thru 154)		
156	TOTAL Distribution Expenses (Total of lines 144 and 155)		
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses		
161	(903) Customer Records and Collection Expenses		
162	(904) Uncollectible Accounts		
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)		

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		
168	(908) Customer Assistance Expenses		
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)		
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)		
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	286,554	301,967
182	(921) Office Supplies and Expenses	84,932	86,117
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	895,430	874,155
185	(924) Property Insurance	1,011,248	925,102
186	(925) Injuries and Damages	584,473	608,169
187	(926) Employee Pensions and Benefits	8,803,506	8,046,741
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses		
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses		
192	(930.2) Miscellaneous General Expenses	12,261	9,793
193	(931) Rents		
194	TOTAL Operation (Enter Total of lines 181 thru 193)	11,678,404	10,852,044
195	Maintenance		
196	(935) Maintenance of General Plant		
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	11,678,404	10,852,044
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	221,533,765	224,805,578

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	1,839
6	TIME WARNER MIDWEST LLC	10,422
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46	TOTAL	12,261

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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					
2	Steam Production Plant					
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant					
8	Distribution Plant					
9	Regional Transmission and Market Operation					
10	General Plant					
11	Common Plant-Electric	42,456,518				42,456,518
12	TOTAL	42,456,518				42,456,518

B. Basis for Amortization Charges

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

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

Line No.	Classification (a)	Description (b)
1	A - (5)	Ohio River Ecological Research Program
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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.
	70,000	923	70,000		1
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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	16,206,918		
4	Transmission	97,909		
5	Regional Market			
6	Distribution			
7	Customer Accounts			
8	Customer Service and Informational			
9	Sales			
10	Administrative and General	286,554		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	16,591,381		
12	Maintenance			
13	Production	10,738,344		
14	Transmission	126,441		
15	Regional Market			
16	Distribution			
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	10,864,785		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	26,945,262		
21	Transmission (Enter Total of lines 4 and 14)	224,350		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)			
24	Customer Accounts (Transcribe from line 7)			
25	Customer Service and Informational (Transcribe from line 8)			
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	286,554		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	27,456,166		27,456,166
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
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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 47)			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	27,456,166		27,456,166
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	24,499		24,499
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	24,499		24,499
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,728		2,728
74	Gas Plant			
75	Other (provide details in footnote):	199		199
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,927		2,927
77	Other Accounts (Specify, provide details in footnote):			
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90				
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94				
95	TOTAL Other Accounts			
96	TOTAL SALARIES AND WAGES	27,483,592		27,483,592

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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	110	12	900			2,256			
2	February	125	1	900			2,256			
3	March	103	3	1600			2,256			
4	Total for Quarter 1						6,768			
5	April	64	20	100			2,256			
6	May	60	18	2200			2,256			
7	June	71	30	1900			2,256			
8	Total for Quarter 2						6,768			
9	July	91	31	1700			2,256			
10	August	99	28	2000			2,256			
11	September	65	30	1200			2,256			
12	Total for Quarter 3						6,768			
13	October	246	31	2400			2,256			
14	November	97	11	2200			2,256			
15	December	81	15	1900			2,256			
16	Total for Quarter 4						6,768			
17	Total Year to Date/Year						27,072			

Schedule Page: 400 Line No.: 1 Column: b

Transmission data includes both Ohio Valley Electric Corporation and its wholly owned subsidiary, Indiana-Kentucky Electric Corporation. This information is not tracked on an individual company basis.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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)	
3	Steam	5,722,980			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional				
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	5,722,980
7	Other				
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	5,722,980	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases		27	Total Energy Losses	
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	5,722,980
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)	5,722,980			

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	525,652	525,652	1,202	23	1300
30	February	453,013	453,013	1,180	28	1400
31	March	598,899	598,899	1,197	21	1800
32	April	341,480	341,480	968	3	1900
33	May	409,805	409,805	996	16	2000
34	June	428,087	428,087	1,157	22	2100
35	July	568,086	568,086	1,440	30	1300
36	August	492,591	492,591	1,145	1	1900
37	September	356,802	356,802	959	19	2000
38	October	447,889	447,889	1,192	22	2100
39	November	585,703	585,703	1,202	14	0700
40	December	514,973	514,973	1,208	19	0900
41	TOTAL	5,722,980	5,722,980			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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: *CLIFTY CREEK* (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	STEAM	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	CONVENTIONAL	
3	Year Originally Constructed	1955	
4	Year Last Unit was Installed	1955	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	1303.56	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	1440	0
7	Plant Hours Connected to Load	8760	0
8	Net Continuous Plant Capability (Megawatts)	1284	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	1284	0
11	Average Number of Employees	304	0
12	Net Generation, Exclusive of Plant Use - KWh	5722980000	0
13	Cost of Plant: Land and Land Rights	1345194	0
14	Structures and Improvements	396403974	0
15	Equipment Costs	971344319	0
16	Asset Retirement Costs	0	0
17	Total Cost	1369093487	0
18	Cost per KW of Installed Capacity (line 17/5) Including	1050.2727	0
19	Production Expenses: Oper, Supv, & Engr	4757949	0
20	Fuel	141269747	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	5287466	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	3892922	0
26	Misc Steam (or Nuclear) Power Expenses	10460411	0
27	Rents	0	0
28	Allowances	3536	0
29	Maintenance Supervision and Engineering	4375723	0
30	Maintenance of Structures	2705356	0
31	Maintenance of Boiler (or reactor) Plant	27916326	0
32	Maintenance of Electric Plant	7844052	0
33	Maintenance of Misc Steam (or Nuclear) Plant	799731	0
34	Total Production Expenses	209313219	0
35	Expenses per Net KWh	0.0366	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	COAL	OIL				
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	TONS	GALLONS				
38	Quantity (Units) of Fuel Burned	2700525	600166	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11416	136000	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	50.984	2.065	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	49.847	1.961	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	218.508	1381.358	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.026	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10788.000	0.000	0.000	0.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
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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

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 402 Line No.: 43 Column: b1

Includes both coal and oil.

Schedule Page: 402 Line No.: 44 Column: b1

Includes both coal and oil.

Name of Respondent Indiana-Kentucky Electric Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2019	Year/Period of Report End of 2019/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Clifty Creek	Dearborn	345.00	330.00	Steel Tower	42.20		2
2								
3								
4	Clifty Creek	Ind.-Ky State Line						
5		(Pierce)	345.00	330.00	Steel Tower	0.20		2
6								
7								
8	Dearborn	Ind.-Ky State Line						
9		(Pierce)	345.00	330.00	Steel Tower	0.50		1
10								
11								
12	Clifty Creek	Junction Miami Ft.-						
13		Louisville Line	138.00	132.00	Steel Tower	0.30		2
14								
15								
16	Clifty Creek	Ind.-Ky State Line						
17		(Carrollton)	138.00	132.00	Steel Tower	1.50		1
18								
19								
20	Dearborn	Ind.-Ky State Line						
21		(Buffington-CG&E)	345.00	330.00	Steel Tower		0.50	1
22								
23								
24	Expenses Applicable							
25	To all Lines							
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	44.70	0.50	9

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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)	
1.75 in.	167,186	4,570,385	4,737,571					1
ACSR								2
								3
								4
1.75 in.		65,275	65,275					5
aluminum								6
								7
								8
1.75 in.		151,149	151,149					9
aluminum								10
								11
								12
795,000 cm		16,982	16,982					13
ACSR								14
								15
								16
556,000 cm								17
ACSR								18
								19
								20
1.75 in.								21
aluminum								22
								23
								24
				342,130	542,142		884,272	25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	167,186	4,803,791	4,970,977	342,130	542,142		884,272	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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20					
21					
22					
23					
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37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
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						19
						20
						21
						22
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						24
						25
						26
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						37
						38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana-Kentucky Electric Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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	Operation, Maint., and Engineering	American Electric Power	107, 401-10, 401-20	1,409,539
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
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