COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE ADJUSTMENT
OF ELECTRIC RATES OF DUKE ENERGY KENTUCKY, INC.

CASE NO. 2022-00372

FILING REQUIREMENTS

VOLUME 1

Duke Energy Kentucky, Inc.
Case No. 2022-00372
Forecasted Test Period Filing Requirements
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1	6	807 KAR 5:001 Section 14(3)	If a limited liability company, the applicant shall identify in the application the state in which it is organized and the date on which it was organized, attest that it is in good standing in the state in which it is organized, and, if it is not a Kentucky limited liability company, state if it is authorized to transact business in Kentucky.	Amy B. Spiller
1	7	807 KAR 5:001 Section 14(4)	If the applicant is a limited partnership, a certified copy of its limited partnership agreement and all amendments, if any, shall be annexed to the application, or a written statement attesting that its partnership agreement and all amendments have been filed with the commission in a prior proceeding and referencing the case number of the prior proceeding.	Amy B. Spiller
1	8	807 KAR 5:001 Section 16 (1)(b)(1)	Reason adjustment is required.	Amy B. Spiller Sarah E. Lawler
1	9	807 KAR 5:001 Section 16 (1)(b)(2)	Certified copy of certificate of assumed name required by KRS 365.015 or statement that certificate not necessary.	Amy B. Spiller
1	10	807 KAR 5:001 Section 16 (1)(b)(3)	New or revised tariff sheets, if applicable in a format that complies with 807 KAR 5:011 with an effective date not less than thirty (30) days from the date the application is filed	Bruce L. Sailers
1	11	807 KAR 5:001 Section 16 (1)(b)(4)	Proposed tariff changes shown by present and proposed tariffs in comparative form or by indicating additions in italics or by underscoring and striking over deletions in current tariff.	Bruce L. Sailers
1	12	807 KAR 5:001 Section 16 (1)(b)(5)	A statement that notice has been given in compliance with Section 17 of this administrative regulation with a copy of the notice.	Amy B. Spiller
1	13	807 KAR 5:001 Section 16(2)	If gross annual revenues exceed $5,000,000, written notice of intent filed at least 30 days, but not more than 60 days prior to application. Notice shall state whether application will be supported by historical or fully forecasted test period.	Amy B. Spiller
1	14	807 KAR 5:001 Section 16(3)	Notice given pursuant to Section 17 of this administrative regulation shall satisfy the requirements of 807 KAR 5:051, Section 2.	Amy B. Spiller
1	15	807 KAR 5:001 Section 16(6)(a)	The financial data for the forecasted period shall be presented in the form of pro forma adjustments to the base period.	Grady “Tripp” S. Carpenter
1	16	807 KAR 5:001 Section 16(6)(b)	Forecasted adjustments shall be limited to the twelve (12) months immediately following the suspension period.	Grady “Tripp” S. Carpenter Lisa D. Steinkuhl Huyen C. Dang
1	17	807 KAR 5:001 Section 16(6)(c)	Capitalization and net investment rate base shall be based on a thirteen (13) month average for the forecasted period.	Lisa D. Steinkuhl
1	18	807 KAR 5:001 Section 16(6)(d)	After an application based on a forecasted test period is filed, there shall be no revisions to the forecast, except for the correction of mathematical errors, unless the revisions reflect statutory or regulatory enactments that could not, with reasonable diligence, have been included in the forecast on the date it was filed. There shall be no revisions filed within thirty (30) days of a scheduled hearing on the rate application.	Grady “Tripp” S. Carpenter

1	19	807 KAR 5:001 Section 16(6)(e)	The commission may require the utility to prepare an alternative forecast based on a reasonable number of changes in the variables, assumptions, and other factors used as the basis for the utility's forecast.	Grady "Tripp" S. Carpenter
1	20	807 KAR 5:001 Section 16(6)(f)	The utility shall provide a reconciliation of the rate base and capital used to determine its revenue requirements.	Lisa D. Steinkuhl
1	21	807 KAR 5:001 Section 16(7)(a)	Prepared testimony of each witness supporting its application including testimony from chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program.	All Witnesses
1	22	807 KAR 5:001 Section 16(7)(b)	Most recent capital construction budget containing at minimum 3 year forecast of construction expenditures.	Grady "Tripp" S. Carpenter Dominic "Nick" J. Melillo William C. Luke
1	23	807 KAR 5:001 Section 16(7)(c)	Complete description, which may be in prefiled testimony form, of all factors used to prepare forecast period. All econometric models, variables, assumptions, escalation factors, contingency provisions, and changes in activity levels shall be quantified, explained, and properly supported.	Grady "Tripp" S. Carpenter
1	24	807 KAR 5:001 Section 16(7)(d)	Annual and monthly budget for the 12 months preceding filing date, base period and forecasted period.	Grady "Tripp" S. Carpenter
1	25	807 KAR 5:001 Section 16(7)(e)	Attestation signed by utility's chief officer in charge of Kentucky operations providing: 1. That forecast is reasonable, reliable, made in good faith and that all basic assumptions used have been identified and justified; and 2. That forecast contains same assumptions and methodologies used in forecast prepared for use by management, or an identification and explanation for any differences; and 3. That productivity and efficiency gains are included in the forecast.	Amy B. Spiller
1	26	807 KAR 5:001 Section 16(7)(f)	For each major construction project constituting 5% or more of annual construction budget within 3 year forecast, following information shall be filed: 1. Date project began or estimated starting date; 2. Estimated completion date; 3. Total estimated cost of construction by year exclusive and inclusive of Allowance for Funds Used During construction ("AFUDC") or Interest During construction Credit; and 4. Most recent available total costs incurred exclusive and inclusive of AFUDC or Interest During Construction Credit.	Grady "Tripp" S. Carpenter Dominic "Nick" J. Melillo William C. Luke
1	27	807 KAR 5:001 Section 16(7)(g)	For all construction projects constituting less than 5% of annual construction budget within 3 year forecast, file aggregate of information requested in paragraph (f) 3 and 4 of this subsection.	Grady "Tripp" S. Carpenter Dominic "Nick" J. Melillo William C. Luke

1	28	807 KAR 5:001 Section 16(7)(h)	Financial forecast for each of 3 forecasted years included in capital construction budget supported by underlying assumptions made in projecting results of operations and including the following information: 1. Operating income statement (exclusive of dividends per share or earnings per share); 2. Balance sheet; 3. Statement of cash flows; 4. Revenue requirements necessary to support the forecasted rate of return; 5. Load forecast including energy and demand (electric); 6. Access line forecast (telephone); 7. Mix of generation (electric); 8. Mix of gas supply (gas); 9. Employee level; 10. Labor cost changes; 11. Capital structure requirements; 12. Rate base; 13. Gallons of water projected to be sold (water); 14. Customer forecast (gas, water); 15. MCF sales forecasts (gas); 16. Toll and access forecast of number of calls and number of minutes (telephone); and 17. A detailed explanation of any other information provided.	Grady “Tripp” S. Carpenter Max W. McClellan John D. Swez
1	29	807 KAR 5:001 Section 16(7)(i)	Most recent FERC or FCC audit reports.	Danielle L. Weatherston
1	30	807 KAR 5:001 Section 16(7)(j)	Prospectuses of most recent stock or bond offerings.	Christopher R. Bauer
1	31	807 KAR 5:001 Section 16(7)(k)	Most recent FERC Form 1 (electric), FERC Form 2 (gas), or PSC Form T (telephone).	Danielle L. Weatherston
2	32	807 KAR 5:001 Section 16(7)(l)	Annual report to shareholders or members and statistical supplements for the most recent 2 years prior to application filing date.	Christopher R. Bauer
3	33	807 KAR 5:001 Section 16(7)(m)	Current chart of accounts if more detailed than Uniform System of Accounts charts.	Danielle L. Weatherston
3	34	807 KAR 5:001 Section 16(7)(n)	Latest 12 months of the monthly managerial reports providing financial results of operations in comparison to forecast.	Danielle L. Weatherston
3	35	807 KAR 5:001 Section 16(7)(o)	Complete monthly budget variance reports, with narrative explanations, for the 12 months prior to base period, each month of base period, and subsequent months, as available.	Grady “Tripp” S. Carpenter Danielle L. Weatherston
3-8	36	807 KAR 5:001 Section 16(7)(p)	SEC’s annual report for most recent 2 years, Form 10-Ks and any Form 8-Ks issued during prior 2 years and any Form 10-Qs issued during past 6 quarters.	Danielle L. Weatherston
8	37	807 KAR 5:001 Section 16(7)(q)	Independent auditor’s annual opinion report, with any written communication which indicates the existence of a material weakness in internal controls.	Danielle L. Weatherston
8	38	807 KAR 5:001 Section 16(7)(r)	Quarterly reports to the stockholders for the most recent 5 quarters.	Christopher R. Bauer

8	39	807 KAR 5:001 Section 16(7)(s)	Summary of latest depreciation study with schedules itemized by major plant accounts, except that telecommunications utilities adopting PSC's average depreciation rates shall identify current and base period depreciation rates used by major plant accounts. If information has been filed in another PSC case, refer to that case's number and style.	John J. Spanos
8	40	807 KAR 5:001 Section 16(7)(t)	List all commercial or in-house computer software, programs, and models used to develop schedules and work papers associated with application. Include each software, program, or model; its use; identify the supplier of each; briefly describe software, program, or model; specifications for computer hardware and operating system required to run program	Lisa D. Steinkuhl
8	41	807 KAR 5:001 Section 16(7)(u)	If utility had any amounts charged or allocated to it by affiliate or general or home office or paid any monies to affiliate or general or home office during the base period or during previous 3 calendar years, file: 1. Detailed description of method of calculation and amounts allocated or charged to utility by affiliate or general or home office for each allocation or payment; 2. method and amounts allocated during base period and method and estimated amounts to be allocated during forecasted test period; 3. Explain how allocator for both base and forecasted test period was determined; and 4. All facts relied upon, including other regulatory approval, to demonstrate that each amount charged, allocated or paid during base period is reasonable.	Jeffrey R. Setser
9	42	807 KAR 5:001 Section 16(7)(v)	If gas, electric or water utility with annual gross revenues greater than $5,000,000, cost of service study based on methodology generally accepted in industry and based on current and reliable data from single time period.	James E. Ziolkowski
9	43	807 KAR 5:001 Section 16(7)(w)	Local exchange carriers with fewer than 50,000 access lines need not file cost of service studies, except as specifically directed by PSC. Local exchange carriers with more than 50,000 access lines shall file: 1. Jurisdictional separations study consistent with Part 36 of the FCC's rules and regulations; and 2. Service specific cost studies supporting pricing of services generating annual revenue greater than $1,000,000 except local exchange access: a. Based on current and reliable data from single time period; and b. Using generally recognized fully allocated, embedded, or incremental cost principles.	N/A
9	44	807 KAR 5:001 Section 16(8)(a)	Jurisdictional financial summary for both base and forecasted periods detailing how utility derived amount of requested revenue increase.	Lisa D. Steinkuhl

9	45	807 KAR 5:001 Section 16(8)(b)	Jurisdictional rate base summary for both base and forecasted periods with supporting schedules which include detailed analyses of each component of the rate base.	Lisa D. Steinkuhl Huyen C. Dang Grady "Tripp" S. Carpenter John R. Panizza James E. Ziolkowski Danielle L. Weatherston
9	46	807 KAR 5:001 Section 16(8)(c)	Jurisdictional operating income summary for both base and forecasted periods with supporting schedules which provide breakdowns by major account group and by individual account.	Lisa D. Steinkuhl
9	47	807 KAR 5:001 Section 16(8)(d)	Summary of jurisdictional adjustments to operating income by major account with supporting schedules for individual adjustments and jurisdictional factors.	Lisa D. Steinkuhl Grady "Tripp" S. Carpenter Huyen C. Dang James E. Ziolkowski
9	48	807 KAR 5:001 Section 16(8)(e)	Jurisdictional federal and state income tax summary for both base and forecasted periods with all supporting schedules of the various components of jurisdictional income taxes.	John R. Panizza
9	49	807 KAR 5:001 Section 16(8)(f)	Summary schedules for both base and forecasted periods (utility may also provide summary segregating items it proposes to recover in rates) of organization membership dues; initiation fees; expenditures for country club; charitable contributions; marketing, sales, and advertising; professional services; civic and political activities; employee parties and outings; employee gifts; and rate cases.	Lisa D. Steinkuhl
9	50	807 KAR 5:001 Section 16(8)(g)	Analyses of payroll costs including schedules for wages and salaries, employee benefits, payroll taxes, straight time and overtime hours, and executive compensation by title.	Lisa D. Steinkuhl Jacob J. Stewart
9	51	807 KAR 5:001 Section 16(8)(h)	Computation of gross revenue conversion factor for forecasted period.	Lisa D. Steinkuhl
9	52	807 KAR 5:001 Section 16(8)(i)	Comparative income statements (exclusive of dividends per share or earnings per share), revenue statistics and sales statistics for 5 calendar years prior to application filing date, base period, forecasted period, and 2 calendar years beyond forecast period.	Danielle L. Weatherston Grady "Tripp" S. Carpenter
9	53	807 KAR 5:001 Section 16(8)(j)	Cost of capital summary for both base and forecasted periods with supporting schedules providing details on each component of the capital structure.	Christopher R. Bauer
9	54	807 KAR 5:001 Section 16(8)(k)	Comparative financial data and earnings measures for the 10 most recent calendar years, base period, and forecast period.	Huyen C. Dang Danielle L. Weatherston Christopher R. Bauer Grady "Tripp" S. Carpenter
9	55	807 KAR 5:001 Section 16(8)(l)	Narrative description and explanation of all proposed tariff changes.	Bruce L. Sailers
9	56	807 KAR 5:001 Section 16(8)(m)	Revenue summary for both base and forecasted periods with supporting schedules which provide detailed billing analyses for all customer classes.	Bruce L. Sailers
9	57	807 KAR 5:001 Section 16(8)(n)	Typical bill comparison under present and proposed rates for all customer classes.	Bruce L. Sailers
9	58	807 KAR 5:001 Section 16(9)	The commission shall notify the applicant of any deficiencies in the application within thirty (30) days of the application's submission. An application shall not be accepted for filing until the utility has cured all noted deficiencies.	Sarah E. Lawler

9	59	807 KAR 5:001 Section 16(10)	Request for waivers from the requirements of this section shall include the specific reasons for the request. The commission shall grant the request upon good cause shown by the utility.	N/A
9	60	807 KAR 5:001 Section (17)(1)	(1) Public postings. (a) A utility shall post at its place of business a copy of the notice no later than the date the application is submitted to the commission. (b) A utility that maintains a Web site shall, within five (5) business days of the date the application is submitted to the commission, post on its Web sites: 1. A copy of the public notice; and 2. A hyperlink to the location on the commission's Web site where the case documents are available. (c) The information required in paragraphs (a) and (b) of this subsection shall not be removed until the commission issues a final decision on the application.	Amy B. Spiller
9	61	807 KAR 5:001 Section 17(2)	(2) Customer Notice. (a) If a utility has twenty (20) or fewer customers, the utility shall mail a written notice to each customer no later than the date on which the application is submitted to the commission. (b) If a utility has more than twenty (20) customers, it shall provide notice by: 1. Including notice with customer bills mailed no later than the date the application is submitted to the commission; 2. Mailing a written notice to each customer no later than the date the application is submitted to the commission; 3. Publishing notice once a week for three (3) consecutive weeks in a prominent manner in a newspaper of general circulation in the utility's service area, the first publication to be made no later than the date the application is submitted to the commission; or 4. Publishing notice in a trade publication or newsletter delivered to all customers no later than the date the application is submitted to the commission. (c) A utility that provides service in more than one (1) county may use a combination of the notice methods listed in paragraph (b) of this subsection.	Amy B. Spiller

9	62	807 KAR 5:001 Section 17(3)	(3) Proof of Notice. A utility shall file with the commission no later than forty-five (45) days from the date the application was initially submitted to the commission: (a) If notice is mailed to its customers, an affidavit from an authorized representative of the utility verifying the contents of the notice, that notice was mailed to all customers, and the date of the mailing; (b) If notice is published in a newspaper of general circulation in the utility's service area, an affidavit from the publisher verifying the contents of the notice, that the notice was published, and the dates of the notice's publication; or (c) If notice is published in a trade publication or newsletter delivered to all customers, an affidavit from an authorized representative of the utility verifying the contents of the notice, the mailing of the trade publication or newsletter, that notice was included in the publication or newsletter, and the date of mailing.	Amy B. Spiller

9	63	807 KAR 5:001 Section 17(4)	(4) Notice Content. Each notice issued in accordance with this section shall contain: (a) The proposed effective date and the date the proposed rates are expected to be filed with the commission; (b) The present rates and proposed rates for each customer classification to which the proposed rates will apply; (c) The amount of the change requested in both dollar amounts and percentage change for each customer classification to which the proposed rates will apply; (d) The amount of the average usage and the effect upon the average bill for each customer classification to which the proposed rates will apply, except for local exchange companies, which shall include the effect upon the average bill for each customer classification for the proposed rate change in basic local service; (e) A statement that a person may examine this application at the offices of (utility name) located at (utility address); (f) A statement that a person may examine this application at the commission's offices located at 211 Sower Boulevard, Frankfort, Kentucky, Monday through Friday, 8:00 a.m. to 4:30 p.m., or through the commission's Web site at http://psc.ky.gov; (g) A statement that comments regarding the application may be submitted to the Public Service Commission through its Web site or by mail to Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602; (h) A statement that the rates contained in this notice are the rates proposed by (utility name) but that the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice; (i) A statement that a person may submit a timely written request for intervention to the Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602, establishing the grounds for the request including the status and interest of the party; and (j) A statement that if the commission does not receive a written request for intervention within thirty (30) days of initial publication or mailing of the notice, the commission may take final action on the application.	Bruce L. Sailers
9	64	807 KAR 5:001 Section 17(5)	(5) Abbreviated form of notice. Upon written request, the commission may grant a utility permission to use an abbreviated form of published notice of the proposed rates, provided the notice includes a coupon that may be used to obtain all the required information.	N/A

10	-	807 KAR 5:001 Section 16(8)(a) through (k)	Schedule Book (Schedules A-K)	Various
11	-	807 KAR 5:001 Section 16(8)(l) through (n)	Schedule Book (Schedules L-N)	Bruce L. Sailers
12	-	-	Work Papers	Various
13	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 1 of 3)	Various
14	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 2 of 3)	Various
15	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 3 of 3)	Various
16-17	-	KRS 278.2205(6)	Cost Allocation Manual	Legal

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR KRS 278.180

KRS 278.180

Description of Filing Requirement:

Provide thirty (30) days' notice of rate change to Kentucky Public Service Commission.

Response:

See attached.

Sponsoring Witness:

Amy B. Spiller

DUKE ENERGY.

Amy B. Spiller
President
Duke Energy Kentucky

139 E. 4th Street
Room 1409-M
Cincinnati, OH 45202

513.287.4359
amy.spiller@duke-energy.com

VIA ELECTRONIC MAIL: PSCED@ky.gov

November 1, 2022

RECEIVED
NOV 01 2022
PUBLIC SERVICE COMMISSION

Ms. Linda Bridwell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602-0615

RE: Case No. 2022-00372
The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.

Dear Ms. Bridwell:

Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company) notifies the Commission that it will file a general electric rate case in thirty days or reasonably soon thereafter.[1] Duke Energy Kentucky will use a forward-looking test period for this case.

Duke Energy Kentucky is contemporaneously filing a Notice of Election of use of Electronic Filing Procedures for this proceeding. Please assign this matter a case number and style and advise us of same so that it can be incorporated in the application and supporting testimony before filing with the Commission.

Duke Energy Kentucky is providing a copy of this notice to the Attorney General's Utility Intervention and Rate Division. We will work diligently with the Commission and our other stakeholders to seek a constructive resolution. Thank you for your consideration.

Sincerely,

Amy B. Spiller

Amy B. Spiller

cc: Hon. John G. Horne, II (via email: rateintervention@ag.ky.gov)

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[1] Duke Energy Kentucky provides this notice pursuant to Commission regulation 807 KAR 5:001 Section 16(2).

Mailing Address
139 East Fourth Street
1303-Main
Cincinnati, Ohio 45202

o: 513-287-4320
f: 513-370-5720

Rocco.D'Ascenzo@duke-energy.com
Rocco O. D'Ascenzo
Deputy General Counsel

VIA ELECTRONIC MAIL: PSCED@ky.gov

November 1, 2022

Ms. Linda Bridwell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602-0615

Re: The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.

Dear Ms. Bridwell:

Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company), pursuant to 807 KAR 5:001, Section 8, is requesting to use the electronic filing procedures set forth in that regulation. Duke Energy Kentucky intends to file on or after December 1, 2022, an Application for Authority to Adjust Electric Rates, Approval of New Tariffs, Approval of Accounting Practices to Establish Regulatory Assets and Liabilities, and for All Other Required Approvals and Relief. The Company would like to utilize the electronic filing procedures when filing documents in this case. As such, I have enclosed a completed *Notice of Election of Use of Electronic Filing Procedures* as required by the Commission.

Should you have any questions regarding the enclosed, please do not hesitate to contact me.

Sincerely,

/s/Rocco D'Ascenzo
Rocco O. D'Ascenzo, Esq.
Deputy General Counsel

NOTICE OF ELECTION OF USE OF ELECTRONIC FILING PROCEDURES
(Complete All Shaded Areas and Check Applicable Boxes)

In accordance with 807 KAR 5:001, Section 8, Duke Energy Kentucky, Inc. gives notice of its intent to file an application for an adjustment of the Electric Rates, etc.... with the Public Service Commission no later than December 1, 2022 and to use the electronic filing procedures set forth in that regulation.

Duke Energy Kentucky, Inc. further states that:

	Yes	No
1. It requests that the Public Service Commission assign a case number to the intended application and advise it of that number as soon as possible;	X	
2. It or its authorized representatives have registered with the Public Service Commission and are authorized to make electronic filings with the Public Service Commission;	X	
3. Neither it nor its authorized representatives have registered with the Public Service Commission for authorization to make electronic filings but will do so no later than seven days before the date of its filing of its application for rate adjustment;		X
4. It or its authorized agents possess the facilities to receive electronic transmissions;	X	

5. The following persons are authorized to make filings on its behalf and to receive electronic service of Public Service Commission orders and any pleadings filed by any party or the Public Service Commission Staff:

Name	Electronic Mail Address
Rocco D'Ascenzo	rocco.d'ascenzo@duke-energy.com
Larisa M. Vaysman Elizabeth Brama	larisa.vaysman@duke-energy.com EBrama@taftlaw.com
Minna Sunderman Debbie Gates	minna.sunderman@duke-energy.com debbie.gates@duke-energy.com

	Yes	No
6. It and its authorized representatives listed above have read and understand the procedures for electronic filing set forth in 807 KAR 5:001 and will fully comply with those procedures unless the Public Service Commission directs otherwise.	X	

Signed /s/Rocco D'Ascenzo

Name: Rocco D'Ascenzo

Title: Deputy General Counsel

Address: 139 East Fourth Street, 1303-Main
Cincinnati, Ohio 45202

Telephone Number: 513-287-4320

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 7(1)

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807 KAR 5:001, SECTION 7(1)

Description of Filing Requirement:

Unless the Commission orders otherwise or the electronic filing procedures established in Section 8 of this administrative regulation are used, if a paper is filed with the commission, an original unbound and ten (10) additional copies in paper medium shall be filed.

Response:

Duke Energy Kentucky elected, and was approved for, the use of electronic filing procedures in this matter. As such, in accordance with 807 KAR 5:001, Section 8(3) and the permanent deviation granted in Case No. 2020-00085,[1] the Company will retain the original filing in paper medium.

Witness Responsible:

Amy B. Spiller

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[1] *In the Matter of Electronic Emergency Docket Related to the Novel Coronavirus COVID-19,* Order, Case No. 2020-00085 (Ky. P.S.C. July 22, 2021).

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 12(2)(a) through (i)

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807 KAR 5:001, SECTIONS 12(2)(a) through 12(2)(i)

Description of Filing Requirements:

Section 12(2)(a)

- Amount and kinds of stock authorized.

Section 12(2)(b)

- Amount and kinds of stock issued and outstanding.

Section 12(2)(c)

- Terms of preference of preferred stock, cumulative or participating, or on dividends or assets or otherwise.

Section 12(2)(d)

- A brief description of each mortgage on property of applicant, giving date of execution, name of mortgagor, name of mortgagee or trustee, amount of indebtedness authorized to be secured, and the amount of indebtedness actually secured, together with sinking fund provisions, if applicable.

Section 12(2)(e)

- The amount of bonds authorized and amount issued, giving the name of the public utility that issued the same, describing each class separately and giving the date of issue, face value, rate of interest, date of maturity, and how secured, together with amount of interest paid during the last fiscal year.

Section 12(2)(f)

- Each note outstanding, giving date of issue, amount, date of maturity, rate of interest, in whose favor, together with amount of interest paid during the last fiscal year.

Section 12(2)(g)

- Other indebtedness, giving same by classes and describing security, if any, with a brief statement of the devolution or assumption of a portion of the indebtedness upon or by person or corporation if the original liability has been transferred, together with amount of interest paid during the last fiscal year.

Section 12(2)(h)

- The rate and amount of dividends paid during the five (5) previous fiscal years, and the amount of capital stock on which dividends were paid each year.

Section 12(2)(i)

- A detailed Income Statement and Balance Sheet.

Response:

See attached.

Sponsoring Witness:

Christopher R. Bauer – Sections 12(2)(a)-(h)
Danielle L. Weatherston – Section 12(2)(i)

FINANCIAL EXHIBIT

(1) Section 12(2)(a) Amount and kinds of stock authorized.

1,000,000 shares of Capital Stock $15 par value amounting to $15,000,000 par value.

(2) Section 12(2)(b) Amount and kinds of stock issued and outstanding.

585,333 shares of Capital Stock $15 par value amounting to $8,779,995 total par value. Total Capital Stock and Additional Paid-in Capital as of September 30, 2022:

Capital Stock and Additional Paid-in Capital
As of September 30, 2022
($ per 1,000)

Capital Stock	$8,780
Premiums thereon	18,839
Total Capital Contributions from Parent (since 2006)	133,594
Contribution from Parent Company for Purchase of Generation Assets	140,061
Total Capital Stock and Additional Paid-in-Capital	$301,274

(3) Section 12(2)(c) Terms of preference or preferred stock, cumulative or participating, or on dividends or assets or otherwise.

There is no preferred stock authorized, issued or outstanding.

(4) Section 12(2)(d) Brief description of each mortgage on property of applicant, giving date of execution, name of mortgagor, name or mortgagee, or trustee, amount of indebtedness authorized to be secured, and the amount of indebtedness actually secured, together with any sinking fund provision.

Duke Energy Kentucky does not have any liabilities secured by a mortgage.

(5) Section 12(2)(e) Amount of bonds authorized, and amount issued, giving the name of the public utility which issued the same, describing each class separately, and giving the date of issue, face value, rate of interest, date of maturity and how secured, together with the amount of interest paid thereon during the last fiscal year.

The Company has 14 outstanding issues of unsecured senior debentures issued under an Indenture dated December 1, 2004, between itself and Deutsche Bank Trust Company Americas, as Trustee, as supplemented by eight Supplemental Indentures. The Indenture allows the Company to issue debt securities in an unlimited amount from time to time. The Debentures issued and outstanding under the Indenture are the following:

Supplemental Indenture	Date of Issue	Principal Amount Authorized and Issued	Principal Amount Outstanding	Rate of Interest	Date of Maturity	Interest Paid Year 2021
1st Supplemental	3/7/2006	65,000,000	65,000,000	6.200%	3/10/2036	4,030,000
3rd Supplemental	1/5/2016	45,000,000	45,000,000	3.420%	1/15/2026	1,539,000
3rd Supplemental	1/5/2016	50,000,000	50,000,000	4.450%	1/15/2046	2,225,000
4th Supplemental	9/7/2017	30,000,000	30,000,000	3.350%	9/15/2029	1,005,000
4th Supplemental	9/7/2017	30,000,000	30,000,000	4.110%	9/15/2047	1,233,000
4th Supplemental	9/7/2017	30,000,000	30,000,000	4.260%	9/15/2057	1,278,000
5th Supplemental	10/3/2018	25,000,000	25,000,000	4.010%	10/15/2023	1,002,500
5th Supplemental	10/3/2018	40,000,000	40,000,000	4.180%	10/15/2028	1,672,000
5th Supplemental	12/12/2018	35,000,000	35,000,000	4.620%	12/15/2048	1,617,000
6th Supplemental	7/17/2019	40,000,000	40,000,000	4.320%	7/15/2049	1,728,000
7th Supplemental	9/26/2019	95,000,000	95,000,000	3.230%	10/01/2025	3,068,500
7th Supplemental	9/26/2019	75,000,000	75,000,000	3.560%	10/01/2029	2,670,000
8th Supplemental	9/15/2020	35,000,000	35,000,000	2.650%	9/15/2030	927,500
8th Supplemental	9/15/2020	35,000,000	35,000,000	3.660%	9/15/2050	1,281,000
			630,000,000			25,276,500

(6) Section 12(2)(f) Each note outstanding, giving date of issue, amount, date of maturity, rate of interest, in whose favor, together with amount of interest paid thereon during the last fiscal year.

The Company has one outstanding $50,000,000 unsecured, two-year bank term loan note issued on October 12, 2021. Interest accrues at an annual rate equal to 60 basis points plus Daily Simple SOFR (Secured Overnight Financing Rate) and is paid quarterly. The term loan will mature on October 12, 2023.

Note Outstanding	Date of Issue	Principal Amount Authorized and Outstanding	Rate of Interest	Date of Maturity	Interest Paid Year 2021
Term Loan	10/12/2021	50,000,000	SOFR + 60bps	10/12/2023	70,834

(7) <u>Section 12(2)(g) Other indebtedness, giving same by classes and describing security, if any, with a brief statement of the devolution or assumption of any portion of such indebtedness upon or by person or corporation if the original liability has been transferred, together with amount of interest paid thereon during the last fiscal year.</u>

The Company has two series of Pollution Control Revenue Refunding Bonds issued under a Trust Indenture dated as of August 1, 2006 and a Trust Indenture dated as of December 1, 2008, between the County of Boone, Kentucky and Deutsche Bank National Trust Company as Trustee. The Company's obligation to make payments equal to debt service on the Bonds is evidenced by a Loan Agreement dated as of August 1, 2006 and December 1, 2008 between the County of Boone, Kentucky and Duke Energy Kentucky. The Bonds issued under the Indentures are below. On Nov 1, 2021, the Company bought in the Series 2008A bond, and remarketed the bond in June 2022.

Indenture	Date of Issue	Principal Amount Authorized and Issued	Principal Amount Outstanding	Rate of Interest	Date of Maturity	Interest Paid Year 2021
Series 2010	11/24/2010	26,720,000	26,720,000	3.86% [1]	8/1/2027	1,031,392
Series 2008A	12/01/2011	50,000,000	<u>50,000,000</u>	3.70% [2]	8/1/2027	<u>465,901</u>
			76,720,000			1,497,292

[1] The bonds were issued at a variable-rate and were swapped to a fixed rate of 3.86% for the life of the debt. The average floating-rate of interest on the bonds for 2021 was 0.067%.
[2] Bonds were remarketed in June 2022 under a fixed-to-maturity interest rate mode (3.70% coupon), however interest paid represents sum of 2021 interest payments.

The Company has no outstanding financing leases as of September 30, 2022.

The Company also has $99,494,000 of money pool borrowings outstanding as of September 30, 2022, $25,000,000 of which is classified as Long-Term Debt payable to affiliated companies. This obligation, which is short-term by nature, is classified as long-term due to Duke Energy Kentucky's intent and ability to utilize such borrowings as long-term financing.

(8) **<u>Section 12(2)(h) Rate and amount of dividends paid during the last five (5) previous fiscal years, and the amount of capital stock on which dividends were paid each year.</u>**

DIVIDENDS PER SHARE

Year Ending	Per Share	Total	No. of Shares	Par Value of Stock
December 31, 2017	0	0	585,333	8,779,995
December 31, 2018	0	0	585,333	8,779,995
December 31, 2019	0	0	585,333	8,779,995
December 31, 2020	0	0	585,333	8,779,995
December 31, 2021	0	0	585,333	8,779,995

(9) **<u>Section 12(2)(i) A detailed Income Statement and Balance Sheet.</u>**

FINANCIAL STATEMENTS

DUKE ENERGY KENTUCKY, INC.
Condensed Statements of Operations
(Unaudited)

	Nine Months Ended September 30,	
(in thousands)	**2022**	**2021**
Operating Revenues		
Electric	$ 371,882	$ 301,517
Natural gas	106,432	75,831
Total operating revenues	478,314	377,348
Operating Expenses		
Fuel used in electric generation and purchased power	163,174	95,645
Cost of natural gas	46,509	25,516
Operation, maintenance and other	109,125	108,321
Depreciation and amortization	64,807	62,375
Property and other taxes	16,571	14,569
Impairment of assets and other charges	—	1,205
Total operating expenses	400,186	307,631
Gains on Sales of Other Assets and Other, net	52	149
Operating Income	78,180	69,866
Other Income and Expenses, net	3,262	3,445
Interest Expense	20,811	19,775
Income Before Income Taxes	60,631	53,536
Income Tax Expense	9,798	9,182
Net Income	$ 50,833	$ 44,354

DUKE ENERGY KENTUCKY, INC.
Condensed Balance Sheets
(Unaudited)

(in thousands, except share amounts)	September 30, 2022	December 31, 2021
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 2,284**	$ 5,483
Receivables (net of allowance for doubtful accounts of $476 at 2022 and $315 at 2021)	**6,919**	7,658
Receivables from affiliated companies	**47,479**	31,503
Inventory	**46,312**	49,534
Regulatory assets	**34,864**	35,031
Other	**41,376**	21,849
Total current assets	**179,234**	151,058
Property, Plant and Equipment		
Cost	**3,186,270**	3,081,412
Accumulated depreciation and amortization	**(1,054,202)**	(1,063,561)
Facilities to be retired, net	**—**	1,769
Net property, plant and equipment	**2,132,068**	2,019,620
Other Noncurrent Assets		
Regulatory assets	**74,301**	115,166
Operating lease right-of-use assets, net	**8,115**	8,407
Other	**19,315**	17,656
Total other noncurrent assets	**101,731**	141,229
Total Assets	**$ 2,413,033**	$ 2,311,907
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	**$ 43,810**	$ 45,939
Accounts payable to affiliated companies	**20,899**	14,763
Notes payable to affiliated companies	**74,494**	102,596
Taxes accrued	**25,479**	20,982
Interest accrued	**6,766**	7,530
Asset retirement obligations	**23,042**	12,867
Regulatory liabilities	**14,266**	9,241
Other	**16,347**	16,234
Total current liabilities	**225,103**	230,152
Long-Term Debt	**754,095**	704,221
Long-Term Debt Payable to Affiliated Companies	**25,000**	25,000
Other Noncurrent Liabilities		
Deferred income taxes	**286,392**	267,959
Asset retirement obligations	**87,930**	80,415
Regulatory liabilities	**108,400**	120,630
Operating lease liabilities	**8,123**	8,379
Accrued pension and other post-retirement benefit costs	**24,904**	30,910
Other	**20,620**	22,608
Total other noncurrent liabilities	**536,369**	530,901
Commitments and Contingencies		
Equity		
Common stock, $15.00 par value, 1,000,000 shares authorized and 585,333 shares outstanding	**8,780**	8,780
Additional paid-in capital	**292,494**	292,494
Retained earnings	**571,192**	520,359
Total equity	**872,466**	821,633
Total Liabilities and Equity	**$ 2,413,033**	$ 2,311,907

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 14(1)

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807 KAR 5:001, SECTION 14(1)

Description of Filing Requirement:

Each application shall state the full name, mailing address, and electronic mail address of the applicant, and shall contain fully the facts on which the application is based, with a request for the order, authorization, permission, or certificate desired and a reference to the particular law requiring or providing for the information.

Response:

See application submitted in this proceeding.

Sponsoring Witness:

Amy B. Spiller

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 14(2)

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807 KAR 5:001, SECTION 14(2)

Description of Filing Requirement:

If a corporation, the applicant shall identify in the application the state in which it is incorporated and the date of its incorporation, attest that it is currently in good standing in the state in which it is incorporated, and, if it is not a Kentucky corporation, state if it is authorized to transact business in Kentucky.

Response:

See attached.

Sponsoring Witness:

Amy B. Spiller

Commonwealth of Kentucky
Michael G. Adams, Secretary of State

Michael G. Adams
Secretary of State
P. O. Box 718
Frankfort, KY 40602-0718
(502) 564-3490
http://www.sos.ky.gov

Certificate of Existence

Authentication number: 281021
Visit https://web.sos.ky.gov/ftshow/certvalidate.aspx to authenticate this certificate.

I, Michael G. Adams, Secretary of State of the Commonwealth of Kentucky, do hereby certify that according to the records in the Office of the Secretary of State,

DUKE ENERGY KENTUCKY, INC.

is a corporation duly incorporated and existing under KRS Chapter 14A and KRS Chapter 271B, whose date of incorporation is March 20, 1901 and whose period of duration is perpetual.

I further certify that all fees and penalties owed to the Secretary of State have been paid; that Articles of Dissolution have not been filed; and that the most recent annual report required by KRS 14A.6-010 has been delivered to the Secretary of State.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my Official Seal at Frankfort, Kentucky, this 15th day of November, 2022, in the 231st year of the Commonwealth.

Michael G. Adams

Michael G. Adams
Secretary of State
Commonwealth of Kentucky
281021/0052929

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 14(3)

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807 KAR 5:001, SECTION 14(3)

Description of Filing Requirement:

If a limited liability company, the applicant shall identify in the application the state in which it is organized and the date on which it was organized, attest that it is in good standing in the state in which it is organized, and, if it is not a Kentucky limited liability company, state if it is authorized to transact business in Kentucky.

Response:

Duke Energy Kentucky is a corporation; therefore, this requirement does not apply.

Sponsoring Witness:

Amy B. Spiller

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 14(4)

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807 KAR 5:001, SECTION 14(4)

Description of Filing Requirement:

If the applicant is a limited partnership, a certified copy of its limited partnership agreement and all amendments, if any, shall be annexed to the application, or a written statement attesting that its partnership agreement and all amendments have been filed with the commission in a prior proceeding and referencing the case number of the prior proceeding.

Response:

Duke Energy Kentucky is a corporation; therefore, this requirement does not apply.

Sponsoring Witness:

Amy B. Spiller

<u>807 KAR 5:001, SECTION 16(1)(b)(1)</u>

<u>Description of Filing Requirement:</u>

Statement of the reason the adjustment is required.

<u>Response:</u>

1) Duke Energy Kentucky's current base rates reflect its cost of service as prepared in 2019. At current rates, the Company's calculated rate of return on rate base for the test period is 2.738%, which is not sufficient to enable the Company to furnish safe, efficient and reliable service and to have the opportunity to earn a fair rate of return on its investments.
2) Duke Energy Kentucky needs to adjust its current costs of service to reflect its current depreciation rates, capital investments and operations and maintenance of its electric operations that have changed since its 2019 case.
   a. A significant driver of this requested increase is an increase in depreciation expense. This is driven by increased plant-in-service since the last rate case and the need to align the depreciable lives of the Company's power plants, East Bend and Woodsdale, with the end of their service lives.
   b. The thirteen-month average of gross plant in this forecasted test period for this case is $2.247 billion, as compared to approximately $1.934 billion included in the 2019 rate case. The depreciation, property taxes, and return on this increased investment are also significant drivers of the need for new rates.

3) Other drivers include:

    a. Need to commence recovery of authorized deferrals (*e.g.*, Planned Outage O&M, and Forced Outage Purchased Power);

    b. Higher O&M expenses since the time of the Company's last electric base rate case.

Please refer to the direct testimony of Duke Energy Kentucky witnesses Amy B. Spiller and Sarah E. Lawler.

<u>Sponsoring Witness:</u>

Amy B. Spiller
Sarah E. Lawler

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(1)(b)(2)

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807 KAR 5:001, SECTION 16(1)(b)(2)

Description of Filing Requirement:

A certified copy of a certificate of assumed name as required by KRS 365.015 or a statement that a certificate is not necessary.

Response:

Duke Energy Kentucky transacts business using the following assumed name: Duke Energy.

A certified copy of the Company's certificate of assumed name is attached.

Sponsoring Witness:

Amy B. Spiller

COMMONWEALTH OF KENTUCKY

Michael G. Adams
Secretary of State

Certificate

I, Michael G. Adams, Secretary of State for the Commonwealth of Kentucky, do hereby certify that the foregoing writing has been carefully compared by me with the original thereof, now in my official custody as Secretary of State and remaining on file in my office, and found to be a true and correct copy of

RENEWAL CERTIFICATE OF ASSUMED NAME OF DUKE ENERGY

RENEWED BY DUKE ENERGY KENTUCKY, INC. FILED ON FEBRUARY 10, 2021.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my Official Seal at Frankfort, Kentucky, this 16th day of November, 2022.

Michael G. Adams

Michael G. Adams
Secretary of State
Commonwealth of Kentucky
kdcoleman/0052929 - Certificate ID: 281158

C227
0052929.04
Michael G. Adams
KY Secretary of State
Received and Filed
2/10/2021 2:15:11 PM
Fee receipt: $20.00

Commonwealth of Kentucky
Michael G. Adams, Secretary of St

Michael G. Adams
Secretary of State
P. O. Box 718
Frankfort, KY 40602-0718
(502) 564-3490
http://www.sos.ky.gov

Renewal Certificate of Assumed Name

REN

This certifies that the assumed name of

DUKE ENERGY

is hereby renewed by

DUKE ENERGY KENTUCKY, INC.

a business entity organized and existing in the state of Kentucky.

Signatures

Signature	Kenna C. Jordan
Title	Assistant Corporate Secretary
Date	2/10/2021 2:15:11 PM

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(1)(b)(3)

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807 KAR 5:001, SECTION 16(1)(b)(3)

Description of Filing Requirement:

New or revised tariff sheets, if applicable in a format that complies with 807 KAR 5:011 with an effective date not less than thirty (30) days from the date the application is filed.

Response:

The proposed tariffs are at Schedule L-1.

Sponsoring Witness:

Bruce L. Sailers

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(1)(b)(4)

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807 KAR 5:001, SECTION 16(1)(b)(4)

Description of Filing Requirement:

New or revised tariff sheets, if applicable, identified in compliance with 807 KAR 5:011, shown either by providing:

a. The present and proposed tariffs in comparative form on the same sheet side by side or on facing sheets side by side; or

b. A copy of the present tariff indicating proposed additions by italicized inserts or underscoring and striking over proposed deletions.

Response:

See Schedules L-2.1 and L-2.2.

Sponsoring Witness:

Bruce L. Sailers

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(1)(b)(5)

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807 KAR 5:001, SECTION 16(1)(b)(5)

Description of Filing Requirement:

A statement that notice has been given in compliance with Section 17 of this administrative regulation with a copy of the notice.

Response:

See attached.

Sponsoring Witness:

Amy B. Spiller

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

CERTIFICATE OF NOTICE

Pursuant to the Kentucky Public Service Commission's Regulation 807 KAR 5:001, Section 16(1)(b)(5), I hereby certify that I am Amy B. Spiller, President of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or Company), a utility furnishing retail electric and gas service within the Commonwealth of Kentucky, which, on the 1st day of December 2022, filed an application with the Kentucky Public Service Commission for the approval of an adjustment of the electric rates, terms, conditions, and tariffs of Duke Energy Kentucky and that notice to the public of the issuing of the same is being given in all respects as required by 807 KAR 5:001, Section 17 and 807 KAR 5:001, Section 8(2), as follows:

On the 1st day of December 2022, the notice to the public was delivered for exhibition and public inspection at 1262 Cox Road, Erlanger, Kentucky 41018 and the same will be kept open to public inspection at said office in conformity with the requirements of 807 KAR 5:001, Section 17(1)(a) and 807 KAR 5:011, Section 8(1).

I further certify that more than twenty (20) customers will be affected by said change by way of an increase in their rates or charges and that on the 21st day of November 2022, there was delivered to the Kentucky Press Association, an agency that acts on behalf of newspapers of general circulation throughout the Commonwealth of Kentucky in which customers affected reside, for publication therein once a week for three consecutive weeks beginning on or before December 1, 2022, a notice of the filing of Duke Energy Kentucky's application, including its proposed rates, a copy of said notice being attached hereto as Exhibit A, and a list of newspapers of general circulation throughout the Commonwealth of Kentucky in which customers affected reside, a copy of said list being attached hereto as Exhibit B. A certificate of publication of said notice will be furnished to the Kentucky Public Service Commission upon completion of same pursuant to 807 KAR 5:001, Section 17(3)(b).

Also beginning on December 1, 2022, Duke Energy Kentucky posted on its website a complete copy of the Company's notice and a hyperlink to the location on the Kentucky Public Service Commission's website where the case documents and tariff filings are available.

Given under my hand this 1st day of December 2022.

Amy B. Spiller
President, Duke Energy Kentucky, Inc.
139 E. 4th Street
Cincinnati, Ohio 45202

Subscribed and sworn to before me, a Notary Public, in and before said County and State, this 1st day of December 2022.

Notary Public

My Commission expires: July 8, 2027

NOTARY PUBLIC STATE OF OHIO

EMILIE SUNDERMAN
Notary Public
State of Ohio
My Comm. Expires
July 8, 2027

NOTICE

Duke Energy Kentucky, Inc. ("Duke Energy Kentucky" or "Company") hereby gives notice that, in an application to be filed no sooner than December 1, 2022, Duke Energy Kentucky will be seeking approval by the Public Service Commission, Frankfort, Kentucky of an adjustment of electric rates and charges proposed to become effective on and after January 3, 2023. The Commission has docketed this proceeding as Case No. 2022-00372.

The proposed electric rates are applicable to the following communities:

Alexandria	Elsmere	Ludlow
Bellevue	Erlanger	Melbourne
Boone County	Fairview	Newport
Bromley	Florence	Park Hills
Campbell County	Fort Mitchell	Pendleton County
Cold Spring	Fort Thomas	Ryland Heights
Covington	Fort Wright	Silver Grove
Crescent Park	Grant County	Southgate
Crescent Springs	Highland Heights	Taylor Mill
Crestview	Independence	Union
Crestview Hills	Kenton County	Villa Hills
Crittenden	Kenton Vale	Walton
Dayton	Lakeside Park	Wilder
Dry Ridge	Latonia Lakes	Woodlawn
Edgewood		

DUKE ENERGY KENTUCKY CURRENT AND PROPOSED ELECTRIC RATES & SIGNIFICANT TEXT CHANGES

Section III – Customer Installations
(Electric Tariff Sheet No. 22)

Current Changes in Installations:
As Company's service drops, transformers, meters, and other facilities used in supplying service to Customer have a limited capacity, Customer should give notice to Company, and obtain Company's consent, before making any material changes or increases in his installation. Company as promptly as possible after receipt of such notice will give its written approval to the proposed change or increase, or will advise Customer upon what conditions service can be supplied for such change or increase. Any change affecting an estimated billing demand shall be rerated by Company's inspector and shall become effective from the succeeding meter reading.

Proposed Changes in Installations:
As Company's service drops, transformers, meters, and other facilities used in supplying service to Customer have a limited capacity, Customer should give notice to Company, and obtain Company's consent, before making any material changes or increases in his installation. Company as promptly as possible after receipt of such notice will give its written approval to the proposed change or increase, or will advise Customer upon what conditions service can be supplied for such change or increase. Customer shall be responsible for costs of upgrades or rearrangement required to the Company's facilities to accommodate the Customer's desired change in installation in accordance with the Company's Line Extension Policy, KY.P.S.C. Electric No. 2, Sheet No. 72. Any change affecting an estimated billing demand shall be rerated by Company's inspector and shall become effective from the succeeding meter reading.

Section VI – Billing and Payment
(Electric Tariff Sheet No. 25)

Current Billing Periods – Time and Place for Payment of Bills:
Bills are due on the date indicated thereon as being the last date for payment of the net amount, or as otherwise agreed to, and bills are payable only at the Company's offices or authorized agencies for collection. When not so paid, the Gross Monthly Bill, which is the Net Monthly Bill plus 5% is due and payable. If a partial payment is made, the amount will be applied to items of indebtedness in the same order as they have accrued, except that any payment received shall first be applied to the bill for service rendered.

Proposed Billing Periods – Time and Place for Payment of Bills::
Bills are due on the date indicated thereon as being the last date for payment of the net amount, or as otherwise agreed to, and bills are payable only at the Company's authorized agencies, mail, or other electronic or non-electronic methods available from the Company for collection. When not so paid, the Gross Monthly Bill, which is the Net Monthly Bill plus 2.3% is due and payable. If a partial payment is made, the amount will be applied to items of indebtedness in the same order as they have accrued, except that any payment received shall first be applied to the bill for service rendered.

Current Change to Optional Rate Schedule:
A customer being billed under one of two or more optional Rate Schedules applicable to his class of service may elect to be billed on any other applicable Rate Schedule by notifying Company in writing, and Company will bill customer under such elected Schedule from and after the date of the next meter reading. However, a customer having made such a change of Rate Schedule may not make another such change within the next twelve months..

Proposed Change to Optional Rate Schedule:
A customer being billed under one of two or more optional Rate Schedules applicable to his class of service may elect to be billed on any other applicable Rate Schedule by notifying Company in writing, and Company will bill customer under such elected Schedule from and after the date of the next meter reading. However, a customer having made such a change of Rate Schedule may not make another such change within the next twelve months or as specified in the Rate Schedule.

Residential Service - Rate RS
(Electric Tariff Sheet No. 30)

	Current Rate	Proposed Rate
Customer Charge per month	$12.60	$13.00
Energy Charge per kWh		
All kWh	8.0995¢	10.7428¢
Late Payment Charge	5%	2.3%

Residential Service Time of Use with Critical Peak Pricing - Rate RS-TOU-CPP
(Electric Tariff Sheet No. 35)

	Current Rate	Proposed Rate	
		Summer	Winter
Customer Charge per month	N/A	$13.00	$13.00
Energy Charge per kWh			
Critical Peak per kWh	N/A	24.8559¢	24.8559¢
On Peak per kWh	N/A	14.9126¢	14.9126¢
Off Peak per kWh	N/A	9.9417¢	9.9417¢
Discount per kWh	N/A	7.9534¢	7.9534¢
Late Payment Charge	N/A	2.3%	2.3%

Service at Secondary Distribution Voltage-Rate DS
(Electric Tariff Sheet No. 40)

	Current Rate	Proposed Rate
Customer Charge per month		
Single Phase Service	$15.00	$15.00
Three Phase Service	$30.00	$30.00
Demand Charge per kW		
First 15 kW	$0.00	$0.00
Additional kilowatts	$9.00	$10.94
Energy Charge per kWh		
First 6,000 kWh	8.9170¢	10.8384¢
Next 300 kWh/kW	5.5342¢	6.7267¢
Additional kWh	4.5604¢	5.5431¢
Non-Church Cap Rate per kWh	25.8792¢	31.4556¢
Church Cap Rate per kWh	15.8876¢	19.3108¢
Late Payment Charge	5%	2.3%

Time-of-Day Rate for Service at Distribution Voltage-Rate DT
(Electric Tariff Sheet No. 41)

	Current Rate		Proposed Rate	
	Summer	Winter	Summer	Winter
Customer Charge per month				
Single Phase Service	$63.50	$63.50	$63.50	$63.50
Three Phase Service	$127.00	$127.00	$127.00	$127.00
Primary Voltage Service	$138.00	$138.00	$138.00	$138.00
Demand Charge per kW				
On Peak kW	$14.85	$14.05	$15.20	$14.38
Off Peak kW	$1.34	$1.34	$1.37	$1.37
Distribution kW	N/A	N/A	$6.23	$6.23
Energy Charge per kWh				
Summer On Peak kWh	4.8389¢	4.6262¢	4.9516¢	4.7338¢
Summer Off Peak kWh	3.9909¢	3.9909¢	4.0836¢	4.0836¢
Metering per kW				
First 1,000 kW On Peak	($0.75)	($0.75)	($0.77)	($0.77)
Additional kW On Peak	($0.58)	($0.58)	($0.59)	($0.59)
Late Payment Charge	5%	5%	2.3%	2.3%

Current Seasonal Definition:
For purposes of administration of the above Base Rate charges, the summer period is defined as that period represented by the Company's billing for the four (4) revenue months of June through September. The winter period is defined as that period represented by the Company's billing for the eight (8) revenue months of January through May and October through December.

Proposed Seasonal Definition:
For purposes of administration of the above Base Rate charges, the summer period is defined as the period June 1 through September 30. The winter period is defined as the period October 1 through May 31.

Current Demand:
The On Peak billing demand shall be the kilowatts derived from the Company's demand meter for the fifteen minute period of greatest use in the on peak rating period adjusted for power factor as provided herein. The Off Peak billing demand shall be the kilowatts derived from the Company's demand meter for the fifteen minute period of greatest use in the off peak rating period adjusted for power factor minus the On Peak billing demand. In no case shall the Off Peak billing demand be less than zero.

Proposed Demand:
The On Peak billing demand shall be the kilowatts derived from the Company's demand meter for the fifteen minute period of greatest use in the on peak rating period adjusted for power factor as provided herein. The Off Peak billing demand shall be the kilowatts derived from the Company's demand meter for the fifteen minute period of greatest use in the off peak rating period adjusted for power factor minus the On Peak billing demand. In no case shall the Off Peak billing demand be less than zero. The Distribution billing demand shall be the kilowatts derived from the Company's demand meter for the fifteen minute period of greatest use in the rating period adjusted for power factor as provided herein.

Optional Rate for Electric Space Heating-Rate EH
(Electric Tariff Sheet No. 42)

	Current Rate	Proposed Rate
Winter Period		
Customer Charge per month		
Single Phase Service	$15.00	$15.00
Three Phase Service	$30.00	$30.00
Primary Voltage Service	$117.00	$117.00
Energy Charge per kWh		
All kWh	6.9268¢	8.3966¢
Late Payment Charge	5%	2.3%

Seasonal Sports Service-Rate SP
(Electric Tariff Sheet No. 43)

	Current Rate	Proposed Rate
Customer Charge per month	$15.00	$15.00
Energy Charge per kWh	10.7965¢	13.2982¢
Late Payment Charge	5%	2.3%

Optional Unmetered General Service Rate
For Small Fixed Loans – Rate GS-FL
(Electric Tariff Sheet No. 44)

	Current Rate	Proposed Rate
For loads based on a range of 540 to 720 hours use per month of the rated capacity of the connected equipment (per kWh)	9.1069¢	11.0107¢
For loads of less than 540 hours use per month of the rated capacity of the connected equipment (per kWh)	10.4699¢	12.6535¢
Minimum per month	$3.23	$3.90
Late Payment Charge	5%	2.3%

Service at Primary Distribution Voltage Applicability-Rate DP
(Electric Tariff Sheet No. 45)

	Current Rate	Proposed Rate
Customer Charge per month		
Primary Voltage Service	$117.00	$117.00
Demand Charge per kW		
All kW	$8.60	$10.16
Energy Charge per kWh		
First 300 kWh/kW	5.7053¢	6.7432¢
Additional kWh	4.8481¢	5.7341¢
Maximum monthly rate per kWh (excluding customer charge and all applicable riders)	26.2020¢	30.9795¢
Late Payment Charge	5%	2.3%

Time-of-Day Rate for Service at Transmission Voltage-Rate TT
(Electric Tariff Sheet No. 51)

	Current Rate		Proposed Rate	
	Summer	Winter	Summer	Winter
Customer Charge per month	$500.00	$500.00	$500.00	$500.00
Demand Charge per kW				
On Peak kW	$8.51	$6.98	$9.74	$7.99
Off Peak kW	$1.29	$1.29	$1.48	$1.48
Energy Charge per kWh				
On Peak kWh	5.3306¢	5.0959¢	6.1035¢	5.8348¢
Off Peak kWh	4.3936¢	4.3936¢	5.0307¢	5.0307¢

Current Seasonal Definition:
For purposes of administration of the above charges, the summer is defined as that period represented by the Company's billing for the four (4) revenue months of June through September. The winter period is defined as that period represented by the Company's billing for the eight (8) revenue months of January through May and October through December.

Proposed Seasonal Definition:
For purposes of administration of the above charges, the summer period is defined as that period June 1 through September 30. The winter period is defined as that period October 1 through May 31.

Rider GSS – Generation Support Service
(Electric Tariff Sheet No. 58)

	Current Rate	Proposed Rate
Administrative Charge per month (plus the appropriate Customer Charge)	$50.00	$50.00
Monthly Transmission and Distribution Reservation Charge (per kW)		
Rate DS Secondary Distribution	$5.6112	$7.8593
Rate DT Distribution Service	$7.1198	$10.3382
Rate DP Primary Distribution	$7.6293	$7.8987
Rate TT Transmission Service	$3.1067	$3.8408

Current Billing:
All Backup Power will be billed at the applicable rate contained in the Company's full service tariff schedules except for the following modifications: 1) the demand ratchet provision, if any, of the Company's full service tariff schedules is waived; and 2) the demand charge for Generation shall be the applicable full service tariff schedule Generation demand charge as shown in Appendix A prorated by the number of days that Backup Power is taken, except that where some of the customer's load requirement for Backup Power and Supplemental Power is 5 MW or greater and such requirement represents new load for ULH&P subsequent to January 1, 2002, the customer's generation charge for energy and demand shall be based on the provisions of Rate RTP-M, Sheet No. 59.

Proposed Billing:
All Backup Power will be billed at the applicable rate contained in the Company's full service tariff schedules except for the following modifications: 1) the demand ratchet provision, if any, of the Company's full service tariff schedules is waived; and 2) the demand charge for Generation shall be the applicable full service tariff schedule Generation demand charge prorated by the number of days that Backup Power is taken.

Rider GTM – Generation Asset True Up Mechanism
(Electric Tariff Sheet No. 57)

Proposed Applicability:
This rider is applicable to all retail sales in the Company's electric service area. Rate RTP program participants utilize the applicable portions of the Baseline Charge and Program Charge, as those terms are defined in Rate RTP, for this rider.
Standard electric rate schedules subject to this schedule are:
Residential: Rate Schedule RS and Rate Schedule RS-TOU-CPP
Non-Residential: Rate Schedules DS, EH, SP, DP, DT, GSFL, TT, SL, TL, UOLS, NSU, SC, SE, and LED

Proposed Rate:
Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2022-00372 dated _ _ _ _ _, 2023 as filed and approved by the Commission, the Company is to recover from retail ratepayers the Retirement Costs of generating units at the East Bend and Woodsdale generating stations and other site-related retirement costs that will not continue in use on a levelized basis over 10 years, including a weighted average cost of capital (WACC) as set in the Company's most recent electric rate case. Revenue collection will begin on the date units are retired. The term Retirement Costs are defined as and shall include the remaining net book value, materials and supplies that cannot be used economically at other plants owned by Duke Energy Kentucky, and removal costs and salvage credits, net of related ADIT. Related ADIT shall include the tax benefits from tax abandonment losses.

The applicable rates for service rendered on and after the retirement date of the generating units to be applied to revenues described below are:
Residential Factor: 0.0000%
Non-residential Factor: 0.0000%

Street Lighting Service-Rate SL
(Electric Tariff Sheet No. 60)

Overhead Distribution Area	Lamp Watts	kW/Unit	Annual kWh	Current Rate/Unit	Proposed Rate/Unit
Standard Fixture (Cobra Head)					
Mercury Vapor					
7,000 lumen	175	0.193	803	$7.92	$11.20
7,000 lumen (Open Refractor)	175	0.205	853	$6.64	$9.39
10,000 lumen	250	0.275	1,144	$9.18	$12.98
21,000 lumen	400	0.430	1,789	$12.32	$17.43
Metal Halide					
14,000 lumen	175	0.193	803	$7.92	$11.20
20,500 lumen	250	0.275	1,144	$9.18	$12.98
36,000 lumen	400	0.430	1,789	$12.32	$17.43

DUKE ENERGY.

NOTICE

Overhead Distribution Area	Lamp Watts	kW/Unit	Annual kWh	Current Rate/Unit	Proposed Rate/Unit
Sodium Vapor					
9,500 lumen	100	0.117	487	$8.71	$12.32
9,500 lumen (Open Refractor)	100	0.117	487	$6.56	$9.28
16,000 lumen	150	0.171	711	$9.53	$13.48
22,000 lumen	200	0.228	948	$12.36	$17.48
27,500 lumen	250	0.275	948	$12.36	$17.48
50,000 lumen	400	0.471	1,959	$16.71	$23.64
Decorative Fixtures					
Sodium Vapor					
9,500 lumen (Rectilinear)	100	0.117	487	$10.82	$15.30
22,000 lumen (Rectilinear)	200	0.246	1,023	$13.43	$19.00
50,000 lumen (Rectilinear)	400	0.471	1,959	$17.86	$25.26
50,000 lumen (Setback)	400	0.471	1,959	$26.43	$37.38
Spans of Secondary Wiring (per month for each increment of 50 feet of secondary wiring beyond the first 150 feet from the pole)				$0.57	$0.81

Underground Distribution Area	Lamp Watts	kW/Unit	Annual kWh	Current Rate/Unit	Proposed Rate/Unit
Standard Fixture (Cobra Head)					
Mercury Vapor					
7,000 lumen	175	0.210	874	$8.07	$11.41
7,000 lumen (Open Refractor)	175	0.205	853	$6.64	$9.39
10,000 lumen	250	0.292	1,215	$9.35	$13.22
21,000 lumen	400	0.460	1,914	$12.63	$17.86
Metal Halide					
14,000 lumen	175	0.210	874	$8.07	$11.41
20,500 lumen	250	0.292	1,215	$9.35	$13.22
36,000 lumen	400	0.460	1,914	$12.63	$17.86
Sodium Vapor					
9,500 lumen	100	0.117	487	$8.71	$12.32
9,500 lumen (Open Refractor)	100	0.117	487	$6.65	$9.41
16,000 lumen	150	0.171	711	$9.50	$13.44
22,000 lumen	200	0.228	948	$12.36	$17.48
27,500 lumen	250	0.318	1,323	$12.41	$17.55
50,000 lumen	400	0.471	1,959	$16.71	$23.64
Decorative Fixtures					
Mercury Vapor					
7,000 lumen (Town & Country)	175	0.205	853	$8.34	$11.80
7,000 lumen (Holphane)	175	0.210	874	$10.45	$14.78
7,000 lumen (Gas Replica)	175	0.210	874	$23.75	$33.60
7,000 lumen (Granville)	175	0.205	853	$8.43	$11.92
7,000 lumen (Aspen)	175	0.210	874	$15.08	$21.33
Metal Halide					
14,000 lumen (Traditionaire)	175	0.205	853	$8.33	$11.78
14,000 lumen (Granville Acorn)	175	0.210	874	$15.08	$21.33
14,000 lumen (Gas Replica)	175	0.210	874	$23.83	$33.71
14,500 lumen (Gas Replica)	175	0.207	861	$23.83	$33.71
Sodium Vapor					
9,500 lumen (Town & Country)	100	0.117	487	$12.08	$17.09
9,500 lumen (Holophane)	100	0.128	532	$13.09	$18.51
9,500 lumen (Rectilinear)	100	0.117	487	$9.77	$ 12.76
9,500 lumen (Gas Replica)	100	0.128	532	$24.56	$34.74
9,500 lumen (Aspen)	100	0.128	532	$15.24	$21.56
9,500 lumen (Traditionaire)	100	0.117	487	$12.08	$17.09
9,500 lumen (Granville Acorn)	100	0.128	532	$15.24	$21.56
22,000 lumen (Rectilinear)	200	0.246	1,023	$13.50	$19.09
50,000 lumen (Rectilinear)	400	0.471	1,959	$17.92	$25.35
50,000 lumen (Setback)	400	0.471	1,959	$26.43	$37.38

Pole Charges	Pole Type	Current Rate/Pole	Proposed Rate/Pole
Wood			
17 foot (Wood laminated)	W17	$4.84	$6.85
30 foot	W30	$4.78	$6.76
35 foot	W35	$4.84	$6.85
40 foot	W40	$5.80	$8.20
Aluminum			
12 foot (decorative)	A12	$13.16	$18.61
28 foot	A28	$7.63	$10.79
28 foot (heavy duty)	A28H	$7.71	$10.91
30 foot (anchor base)	A30	$15.24	$21.56
Fiberglass			
17 foot	F17	$4.84	$6.85
12 foot (decorative)	F12	$14.15	$20.01
30 foot (bronze)	F30	$9.21	$13.03
35 foot (bronze)	F35	$9.46	$13.38
Steel			
27 foot (11 gauge)	S27	$12.44	$17.60
27 foot (3 gauge)	S27H	$18.76	$25.97
Spans of Secondary Wiring (per month for each increment of 25 feet of secondary wiring beyond the first 25 feet from the pole		$0.83	$1.17
Late Payment Charge		5%	2.3%

Current Applicability:
Mercury Vapor lighting fixtures will not be installed by the Company after June 1, 2003. As currently installed Mercury Vapor fixtures are retired and/or replaced, they may be replaced with either Metal Halide or Sodium Vapor fixtures as the customer chooses.

This rate schedule is no longer available after December 31, 2006. Potential lighting customers wanting a lighting system installed and maintained by Company can do so via the Outdoor Lighting Equipment agreement (OLE). Potential customers should contact a Company account representative for further information concerning OLE options. This rate schedule terminates December 31, 2026. Customers currently being provided service under this rate schedule can continue being provided service under this rate schedule for the remaining useful life of the facilities, or this rate schedule terminates, whichever occurs first.

Proposed Applicability:
Mercury Vapor lighting fixtures will not be installed by the Company after June 1, 2003.

This rate schedule is no longer available after December 31, 2006. Customers currently being provided service under this rate schedule can continue being provided service under this rate schedule for the remaining useful life of the facilities, or when this rate schedule terminates, whichever occurs first.

Current Type of Service:
The Company will endeavor to replace burned-out lamps within 48 hours after notification by the customer.

Proposed Type of Service:
The Company will endeavor to replace burned-out lamps within three (3) business days after notification by the customer.

Current General Conditions:
(6) When a street lighting unit reaches end of life or becomes obsolete and parts cannot be reasonably obtained, the Company can remove the unit at no expense to the customer after notifying the customer. The customer shall be given the opportunity to arrange for another type lighting unit provided by the Company.

Proposed General Conditions:
6) When a Company owned street lighting unit and/or pole reaches the end of life or becomes obsolete and parts cannot be reasonably obtained, the Company shall replace lighting unit and/or pole with an available similar LED lighting unit and/or pole and the Customer shall commence being billed on Rate LED for the available similar lighting unit and/or pole rate and will enter into a new lighting agreement within 90 days. The terms of service of Rate LED shall commence upon lighting unit and/or pole installation. If within 90 days of replacement the Customer does not enter into a new agreement, the service may be terminated.

(7) The customer will be responsible for trimming trees and other vegetation that obstruct the light output from fixture(s) or maintenance access to the facilities outside of Company distribution reliability trimming. Company shall not be required to pay for obtaining permission to trim or re-trim trees where such trees interfere with supplying electric energy to the system. Customer shall assist Company, if necessary, in obtaining permission to trim trees where Company is unable to obtain such permission through its own best efforts.

Traffic Lighting Service -Rate TL
(Electric Tariff Sheet No. 61)

	Current Rate	Proposed Rate
Where the Company supplies energy only (per kWh)	4.3437¢	6.1438¢
Where the Company supplies energy from a separately metered source and the Company has agreed to provide limited maintenance for traffic signal equipment (per kWh)	2.3187¢	Discontinued
Where the Company supplies energy and has agreed to provide limited maintenance for traffic signal equipment (per kWh)	6.6624¢	Discontinued
Late Payment Charge	5%	2.3%

Current Limited Maintenance:
Limited maintenance for traffic signals is defined as cleaning and replacing lamps, and repairing connections in wiring which are of a minor nature. Limited maintenance for traffic controllers is defined as cleaning, oiling, adjusting and replacing contacts which are provided by customer, time-setting when requested, and minor repairs to defective wiring.

Proposed Limited Maintenance:
(This Section is proposed to be deleted)

Unmetered Outdoor Lighting Electric Service-Rate UOLS
(Electric Tariff Sheet No. 62)

	Current Rate	Proposed Rate
Energy Charge per kWh		
All kWh	4.2793¢	6.0527¢
Late Payment Charge	5%	2.3%

Current Ownership of Service Lines:
The Company shall not be required to pay for obtaining permission to trim or re-trim trees where such trees interfere with lighting output or with service lines or wires of the Company used for supplying electric energy to the System. The customer shall assist the Company, if necessary, in obtaining permission to trim trees where the Company is unable to obtain such permission through its own best efforts.

Proposed Ownership of Service Lines:
The customer will be responsible for trimming trees and other vegetation that obstruct the light output from fixture(s) or maintenance access to the facilities outside of Company distribution reliability trimming. The Company shall not be required to pay for obtaining permission to trim or re-trim trees where such trees interfere with lighting output or with service lines or wires of the Company used for supplying electric energy to the System. The customer shall assist the Company, if necessary, in obtaining permission to trim trees where the Company is unable to obtain such permission through its own best efforts.

Outdoor Lighting Equipment Installation -Rate OL-E
(Electric Tariff Sheet No. 63)

Current Contract for Service:
The monthly Maintenance Charge covers estimated equipment maintenance costs as specified in the Agreement, including the ongoing costs of ownership such as administration, taxes and insurance. The Agreement allows for re-evaluation and possible adjustment to the maintenance monthly charges every three years.

Proposed Contract for Service:
The monthly Maintenance Charge covers estimated equipment maintenance costs as specified in the Agreement, including the ongoing costs of ownership such as administration, taxes and insurance. The Agreement allows for re-evaluation and possible adjustment to the maintenance monthly charges every three years. The monthly Maintenance Charge does not cover replacement of the fixture upon failure.

Current Ownership of Service Lines:
The Company shall not be required to pay for obtaining permission to trim or re-trim trees where such trees interfere with lighting output or with service lines or wires of the Company used for supplying electric energy to the System. The customer shall assist the Company, if necessary, in obtaining permission to trim trees where the Company is unable to obtain such permission through its own best efforts.

Proposed Ownership of Service Lines:
The customer will be responsible for trimming trees and other vegetation that obstruct the light output from fixture(s) or maintenance access to the facilities outside of Company distribution reliability trimming. The Company shall not be required to pay for obtaining permission to trim or re-trim trees where such trees interfere with lighting output or with service lines or wires of the Company used for supplying electric energy to the System. The customer shall assist the Company, if necessary, in obtaining permission to trim trees where the Company is unable to obtain such permission through its own best efforts.

LED Outdoor Lighting Electric Service- Rate LED
(Electric Tariff Sheet No. 64)

	Current Rate	Proposed Rate
Energy Charge per kWh		
All kWh	4.2793¢	6.0527¢

Current Rates (Per Unit Per Month)

Fixtures Description	Initial Lumens	Lamp Wattage	Monthly kWh	Current Charge		Current Charge	
				Fixture	Maint.	Fixture	Maint.
50W Neighborhood	5,000	50	17	$4.32	$4.56	$4.25	$2.90
50W Neighborhood with Lens	5,000	50	17	$4.50	$4.56	$4.30	$2.90
50W Standard LED-BLACK	4,521	50	17	$5.31	$4.56	$3.93	$2.90
70W Standard LED-BLACK	6,261	70	24	$5.30	$4.56	$4.32	$2.90
110W Standard LED-BLACK	9,336	110	38	$6.01	$4.56	$4.89	$2.90
150W Standard LED-BLACK	12,642	150	52	$7.95	$4.56	$4.94	$2.90
220W Standard LED-BLACK	18,641	220	76	$9.02	$5.56	$6.46	$3.54
280W Standard LED-BLACK	24,191	280	97	$11.10	$5.56	$6.51	$3.54
50W Acorn LED-BLACK	5,147	50	17	$13.95	$4.56	$11.98	$2.90
50W Deluxe Acorn LED-BLACK	5,147	50	17	$15.48	$4.56	$13.36	$2.90
70W LED Open Deluxe Acorn	6,500	70	24	$15.09	$4.56	$13.75	$2.90
50W Traditional LED-BLACK	3,230	50	17	$10.11	$4.56	$6.45	$2.90
50W Open Traditional LED-BLACK	3,230	50	17	$10.11	$4.56	$6.72	$2.90
50W Mini Bell LED-BLACK	4,500	50	17	$13.15	$4.56	$12.30	$2.90
50W Enterprise LED-BLACK	3,880	50	17	$13.58	$4.56	$11.80	$2.90
70W Sanibel LED-BLACK	5,508	70	24	$16.75	$4.56	$15.00	$2.90
150W Sanibel	12,500	150	52	$16.75	$4.56	$15.63	$2.90
150W LED Teardrop	12,500	150	52	$20.27	$4.56	$18.80	$2.90
50W LED Teardrop Pedestrian	4,500	50	17	$16.45	$4.56	$15.36	$2.90
220W LED Shoebox	18,500	220	76	$14.04	$5.56	$11.66	$3.54
420W LED Shoebox	39,078	420	146	$20.95	$5.56	$17.31	$3.54
530W LED Shoebox	57,000	530	184	$26.34	$5.56	$19.95	$3.54
150W Clermont LED	12,500	150	52	$25.00	$4.56	20.51	$2.90
130W Flood LED	14,715	130	45	$8.58	$4.56	$7.37	$2.90
260W Flood LED	32,779	260	90	$13.50	$5.56	$11.50	$3.54
50W Monticello LED	4,157	50	17	$16.69	$4.56	$13.81	$2.90
50W Mitchell Finial	5,678	50	17	$15.83	$4.56	$13.15	$2.90
50W Mitchell Ribs, Bands, and Medallions LED	5,678	50	17	$17.44	$4.56	$14.37	$2.90
50W Mitchell Top Hat LED	5,678	50	17	$15.83	$4.56	$13.15	$2.90
50W Mitchell Top Hat with Ribs, Bands, & Medallions LED	5,678	50	17	$17.44	$4.56	$14.37	$2.90
50W Open Monticello LED	4,157	50	17	$16.62	$4.56	$13.75	$2.90
150W LED Shoebox	19,000	150	52	N/A	N/A	$10.73	$2.90

NOTICE

Fixtures Description	Initial Lumens	Lamp Wattage	Monthly kWh	Current Charge		Current Charge	
				Fixture	Maint.	Fixture	Maint.
40W Acorn No Finial LED	5,000	40	14	N/A	N/A	$11.48	$2.90
50W Ocala Acorn LED	6,582	50	17	N/A	N/A	$6.87	$2.90
50W Deluxe Traditional LED	5,057	50	17	N/A	N/A	$13.12	$2.90
30W Town & Country LED	3,000	30	10	N/A	N/A	$5.47	$2.90
30W Open Town & Country LED	3,000	30	10	N/A	N/A	$5.21	$2.90
150W Enterprise LED	16,500	150	52	N/A	N/A	$11.72	$2.90
220W Enterprise LED	24,000	220	76	N/A	N/A	$12.06	$3.54
50W Clermont LED	6,300	50	17	N/A	N/A	$19.12	$2.90
30W Gaslight Replica LED	3,107	30	10	N/A	N/A	$21.81	$2.90
50W Cobra LED	5,500	50	17	N/A	N/A	$4.27	$2.90
70W Cobra LED	8,600	70	24	N/A	N/A	$4.43	$2.90

Poles		
Description	**Current Charge**	**Proposed Charge**
Style A 12 Ft Long Anchor Base Top Tenon Aluminum	$6.07	$9.67
Style A 15 Ft Long Direct Buried Top Tenon Aluminum	$5.20	$9.00
Style A 15 Ft Long Anchor Base Top Tenon Aluminum	$6.24	$11.22
Style A 18 Ft Long Direct Buried Top Tenon Aluminum	$5.40	$9.21
Style A 17 Ft Long Anchor Base Top Tenon Aluminum	$6.54	$11.96
Style A 25 Ft Long Direct Buried Top Tenon Aluminum	$10.03	$12.17
Style A 22 Ft Long Anchor Base Top Tenon Aluminum	$7.76	$15.09
Style A 30 Ft Long Direct Buried Top Tenon Aluminum	$11.18	$13.82
Style A 27 Ft Long Anchor Base Top Tenon Aluminum	$9.17	$20.18
Style A 35 Ft Long Direct Buried Top Tenon Aluminum	$12.44	$16.05
Style A 32 Ft Long Anchor Base Top Tenon Aluminum	$10.59	$20.71
Style A 41 Ft Long Direct Buried Top Tenon Aluminum	$13.44	$19.65
Style B 12 Ft Long Anchor Base Post Top Aluminum	$7.39	$10.99
Style C 12 Ft Long Anchor Base Post Top Aluminum	$10.01	$13.37
Style C 12 Ft Long Anchor Base Davit Steel	$10.01	$16.20
Style C 14 Ft Long Anchor Base Top Tenon Steel	$10.73	$15.28
Style C 21 Ft Long Anchor Base Davit Steel	$26.33	$34.13
Style C 23 Ft Long Anchor Base Boston Harbor Steel	$26.62	$39.64
Style D 12 Ft Long Anchor Base Breakaway Aluminum	$9.91	$12.76
Style E 12 Ft Long Anchor Base Post Top Aluminum	$10.01	$13.37
Style F 12 Ft Long Anchor Base Post Top Aluminum	$10.72	$16.30
Legacy Style 39 Ft Direct Buried Single or Twin Side Mount Alum Satin Finish	$16.94	$21.67
Legacy Style 27 Ft Long Anchor Base Side Mnt Alum Satin Finish Breakaway	$13.06	$21.18
Legacy Style 33 Ft Long Anchor Base Side Mnt Alum Satin Finish Breakaway	$12.70	$22.14
Legacy Style 37 Ft Long Anchor Base Side Mount Aluminum Pole Satin Finish	$15.70	$24.45
30' Class 7 Wood Pole	$6.21	$6.71
35' Class 5 Wood Pole	$6.75	$7.50
40' Class 4 Wood Pole	$10.16	$8.50
45' Class 4 Wood Pole	$10.54	$8.85
15' Style A - Fluted - for Shroud - Aluminum Direct Buried Pole	$5.03	$10.40
20' Style A - Fluted - for Shroud - Aluminum Direct Buried Pole	$5.61	$10.92
15' Style A - Smooth - for Shroud - Aluminum Direct Buried Pole	$3.32	$9.00
20' Style A - Smooth - for Shroud - Aluminum Direct Buried Pole	$5.17	$10.62
21' Style A - Fluted - Direct Buried	N/A	$14.89
30' Style A - Transformer Base - Anchor Base	N/A	$22.56
35' Style A - Transformer Base - Anchor Base	N/A	$25.40
19' Style A - Breakaway - Direct Buried	N/A	$20.25
24' Style A - Breakaway - Direct Buried	N/A	$21.43
27' Style A - Breakaway - Direct Buried	N/A	$20.49
32' Style A - Breakaway - Direct Buried	N/A	$20.98
37' Style A - Breakaway - Direct Buried	N/A	$22.33
42' Style A - Breakaway - Direct Buried	N/A	$23.08
17' Style B - Anchor Base	N/A	$15.57
17' Style C - Post Top - Anchor Base	N/A	$16.80
17' Style C - Davit - Anchor Base	N/A	$26.57
17' Style C - Boston Harbor - Anchor Base	N/A	$25.91
25' Style D - Boston Harbor - Anchor Base	N/A	$30.21
50' Wood - Direct Buried	N/A	$11.02
55' Wood - Direct Buried	N/A	$11.61
18' Style C - Breakaway - Direct Buried	N/A	$22.97
17' Wood Laminated	N/A	$6.85
12' Aluminum (decorative)	N/A	$18.61
28' Aluminum	N/A	$10.79
28' Aluminum (heavy duty)	N/A	$10.91
30' Aluminum (anchor base)	N/A	$21.56
17' Fiberglass	N/A	$6.85
12' Fiberglass (decorative)	N/A	$20.01
30' Fiberglass (bronze)	N/A	$13.03
35' Fiberglass (bronze)	N/A	$13.38
27' Steel (11 gauge)	N/A	$17.60
27' Steel (3 gauge)	N/A	$25.97
Shroud - Standard Style for anchor base poles	$2.42	$2.81
Shroud - Style B Pole for smooth and fluted poles	$2.28	$6.67
Shroud - Style C Pole for smooth and fluted poles	$2.19	$8.33
Shroud - Style D Pole for smooth and fluted poles	$2.35	$10.29
Shroud - Style B - Assembly	N/A	$8.72
Shroud - Style C - Assembly	N/A	$10.25
Shroud - Style D - Assembly	N/A	$12.49
Shroud - Style Standard - Assembly 6"/15"	N/A	$4.87
Shroud - Style Standard - Assembly 6"/18"	N/A	$5.30

Pole Foundation		
Description	**Current Charge**	**Proposed Charge**
Flush - Pre-fabricated - Style A Pole	$10.23	$13.78
Flush - Pre-fabricated - Style B Pole	$9.22	$12.71
Flush - Pre-fabricated - Style C Pole	$10.84	$13.64
Flush - Pre-fabricated - Style E Pole	$10.23	$12.71
Flush - Pre-fabricated - Style F Pole	$9.22	$12.71
Flush - Pre-fabricated - Style D Pole	$8.98	12.71
Reveal - Pre-fabricated - Style A Pole	$10.87	$19.40

Pole Foundation (cont.)		
Description	**Current Charge**	**Proposed Charge**
Reveal - Pre-fabricated - Style B Pole	$11.61	$15.43
Reveal - Pre-fabricated - Style C Pole	$11.61	$16.01
Reveal - Pre-fabricated - Style D Pole	$11.61	$16.01
Reveal - Pre-fabricated - Style E Pole	$11.61	$16.01
Reveal - Pre-fabricated - Style F Pole	$10.14	$16.01
Screw-in Foundation	$5.70	$8.25

Brackets		
Description	**Current Charge**	**Proposed Charge**
14 inch bracket - wood pole - side mount	$1.36	$2.00
4 foot bracket - wood pole - side mount	$1.47	$2.24
6 foot bracket - wood pole - side mount	$1.34	$2.21
8 foot bracket - wood pole - side mount	$2.17	$2.99
10 foot bracket - wood pole - side mount	$4.49	$4.94
12 foot bracket - wood pole - side mount	$3.56	$4.50
15 foot bracket - wood pole - side mount	$4.33	$5.25
4 foot bracket - metal pole - side mount	$5.22	$5.32
6 foot bracket - metal pole - side mount	$5.58	$5.40
8 foot bracket - metal pole - side mount	$5.62	$6.70
10 foot bracket - metal pole - side mount	$5.92	$7.06
12 foot bracket - metal pole - side mount	$6.73	$6.46
15 foot bracket - metal pole - side mount	$6.88	$7.70
18 inch bracket - metal pole - double Flood Mount - top mount	$2.24	$2.14
14 inch bracket - metal pole - single mount - top tenon	$1.61	$2.27
14 inch bracket - metal pole - double mount - top tenon	$1.99	$2.45
14 inch bracket - metal pole - triple mount - top tenon	$2.46	$2.61
14 inch bracket - metal pole - quad mount - top tenon	$2.29	$2.72
6 foot - metal pole - single - top tenon	$2.42	$5.04
6 foot - metal pole - double - top tenon	$3.86	$6.39
4 foot - Boston Harbor - top tenon	$7.87	$7.31
6 foot - Boston Harbor - top tenon	$8.61	$7.69
12 foot - Boston Harbor Style C pole double mount - top tenon	$15.51	$13.16
4 foot - Davit arm - top tenon	$8.36	$6.67
18 inch - Cobrahead fixture for wood pole	$1.19	$1.89
18 inch - Flood light for wood pole	$1.34	$2.08
18" Metal - Flood - Bullhorn - Top Tenon	N/A	2.56
4' Transmission - Top Tenon	N/A	9.44
10' Transmission - Top Tenon	N/A	10.88
15' Transmission - Top Tenon	N/A	11.97
18" Transmission - Flood - Top Tenon	N/A	5.03
3' Shepherds Crook - Single - Top Tenon	N/A	4.77
3' Shepherds Crook w/ Scroll - Single - Top Tenon	N/A	5.29
3' Shepherds Crook - Double - Top Tenon	N/A	6.76
3' Shepherds Crook w/ Scroll - Double - Top Tenon	N/A	7.59
3' Shepherds Crook w/ Scroll & Festoon - Single - Top Tenon	N/A	5.54
3' Shepherds Crook w/ Scroll - Wood - Top Tenon	N/A	6.60
17" Masterpiece - Top Tenon - Double Post Mount - Top Tenon	N/A	5.27

Wiring Equipment		
Description	**Current Charge**	**Proposed Charge**
Secondary Pedestal (cost per unit)	$2.05	$2.55
Handhole (cost per unit)	$1.70	$3.67
Pullbox	N/A	$9.30
6AL DUPLEX and Trench (cost per foot)	$0.91	$1.16
6AL DUPLEX and Trench with conduit (cost per foot)	$0.95	$1.34
6AL DUPLEX with existing conduit (cost per foot)	$0.88	$0.85
6AL DUPLEX and Bore with conduit (cost per foot)	$1.09	$2.89
6AL DUPLEX OH wire (cost per foot)	$0.87	$2.72
Late Payment Charge	5%	2.3%
Additional Facilities Charge	1.0017%	0.8617%

Current Ownership of Service Lines:
Company shall not be required to pay for obtaining permission to trim or re-trim trees where such trees interfere with supplying electric energy to the System. The Customer shall assist the Company, if necessary, in obtaining permission to trim trees where the Company is unable to obtain such permission through its own best efforts.

Proposed Ownership of Service Lines:
The customer will be responsible for trimming trees and other vegetation that obstruct the light output from fixture(s) or maintenance access to the facilities outside of Company distribution reliability trimming. The Company shall not be required to pay for obtaining permission to trim or re-trim trees where such trees interfere with supplying electric energy to the System. The Customer shall assist the Company, if necessary, in obtaining permission to trim trees where the Company is unable to obtain such permission through its own best efforts.

Current Terms of Service:
1. Service under this rate schedule shall be for a minimum initial term of ten (10) years from the commencement of service and shall continue thereafter until terminated by either party by sixty (60) days written notice or to termination. Upon early termination of service under this schedule, the customer shall pay an amount equal to the remaining monthly lease amount for the term of contract and removal cost of the facilities.

Proposed Terms of Service:
Service under this rate schedule shall be for a minimum initial term of ten (10) years from the commencement of service and shall continue thereafter until terminated by either party by sixty (60) days prior written notice of termination. Upon early termination of service under this schedule, the customer shall pay an amount equal to the remaining monthly lease amount for the term of agreement and removal cost of the facilities. After the minimum initial term is complete, customers are permitted to replace lighting equipment with other options on this Rate LED or other available Company lighting tariffs without a termination charge.

Street Lighting Service for Non-Standard Units -Rate NSU
(Electric Tariff Sheet No. 66)

	Lamp Watts	kW/Unit Wattage	Annual kW/unit	Current Rate/Unit	Proposed Rate/Unit
Company Owned					
Boulevard units served underground					
a. 2,500 lumen Incandescent – Series	148	0.148	616	$10.22	$14.46
b. 2,500 lumen Incandescent – Multiple	189	0.189	786	$7.98	$11.29
Holphane Decorative Fixture on 17 foot fiberglass pole served underground with direct buried cable					
a. 10,000 lumen Mercury Vapor	250	0.292	1,215	$18.63	$26.35
Each increment of 25 feet of secondary wiring beyond the first 25 feet from the pole base (added to Rate/unit charge)				$0.81	$1.15
Street light units served overhead distribution					
a. 2,500 lumen Incandescent	189	0.189	786	$7.91	$11.19
b. 2,500 lumen Mercury Vapor	100	0.109	453	$7.45	$10.54
c. 21,000 lumen Mercury Vapor	400	0.460	1,914	$11.97	$16.93

NOTICE

	Lamp Watts	kW/Unit Wattage	Annual kW/unit	Current Rate/Unit	Proposed Rate/Unit
Customer Owned					
Steel boulevard units served underground with limited maintenance by Company					
a. 2,500 lumen Incandescent – Series	148	0.148	616	$6.06	$8.57
b. 2,500 lumen Incandescent – Multiple	189	0.189	786	$7.71	$10.91
Late Payment Charge				5%	2.3%

Current Applicability:
Mercury Vapor lighting fixtures will not be installed by the Company after June 1, 2003. As currently installed Mercury Vapor fixtures are retired and/or replaced, they may be replaced with either Metal Halide or Sodium Vapor fixtures as the customer chooses.

This rate schedule is no longer available after December 31, 2006. Potential lighting customers wanting a lighting system installed and maintained by Company can do so via the Outdoor Lighting Equipment agreement (OLE). Potential customers should contact a Company account representative for further information concerning OLE options. This rate schedule terminates December 31, 2026. Customers currently being provided service under this rate schedule can continue being provided service under this rate schedule for the remaining useful life of the facilities, or this rate schedule terminates, whichever occurs first.

Proposed Applicability:
Mercury Vapor lighting fixtures will not be installed by the Company after June 1, 2003.

This rate schedule is no longer available after December 31, 2006. Customers currently being provided service under this rate schedule can continue being provided service under this rate schedule for the remaining useful life of the facilities, or when this rate schedule terminates, whichever occurs first.

Current Type of Service:
The Company will endeavor to replace burned-out lamps within 48 hours after notification by the customer.

Proposed Type of Service:
The Company will endeavor to replace burned-out lamps within three (3) business days after notification by the customer.

Current General Conditions:
(3) When a Company owned street lighting unit reaches end of life or becomes obsolete and parts cannot be reasonably obtained, the Company can remove the unit at no expense to the customer after notifying the customer. The customer shall be given the opportunity to arrange for another type lighting unit provided by the Company.

(4) When a customer owned lighting unit becomes inoperative, the cost of repair or replacement of the unit will be at the customer's expense. The replacement unit shall be an approved Company fixture.

Limited maintenance by the Company includes only fixture cleaning, relamping, and glassware and photo cell replacement.

Proposed General Conditions:
(3) When a Company owned street lighting unit and/or pole reaches the end of life or becomes obsolete and parts cannot be reasonably obtained, the Company shall replace lighting unit and/or pole with an available similar LED lighting unit and/or pole and the Customer shall commence being billed on Rate LED for the available similar lighting unit and/or pole rate and will enter into a new lighting agreement within 90 days. The terms of service of Rate LED shall commence upon lighting unit and/or pole installation. If within 90 days of replacement the Customer does not enter into a new agreement, the service may be terminated.

(4) When a customer owned lighting unit becomes inoperative, the cost of repair or replacement of the unit will be at the customer's expense. The replacement unit shall be an approved Company fixture. Upon failure of a customer owned unit, Customer may contact Company to discuss lighting options available with Company owned lighting units.

(5) Limited maintenance by the Company includes only fixture cleaning, relamping, and glassware and photo cell replacement.

(6) The customer will be responsible for trimming trees and other vegetation that obstruct the light output from fixture(s) or maintenance access to the facilities. Company shall not be required to pay for obtaining permission to trim or re-trim trees where such trees interfere with supplying electric energy to the system. Customer shall assist Company, if necessary, in obtaining permission to trim trees where Company is unable to obtain such permission through its own best efforts.

Street Lighting Service-Customer Owned - Rate SC
(Electric Tariff Sheet No. 68)

Fixture Description	Lamp Watts	kW/Unit	Annual kWh	Current Rate/Unit	Proposed Rate/Unit
Base Rate					
Standard Fixture (Cobra Head)					
Mercury Vapor					
7,000 lumen	175	0.193	803	$4.71	$6.66
10,000 lumen	250	0.275	1,144	$6.02	$8.51
21,000 lumen	400	0.430	1,789	$8.37	$11.84
Metal Halide					
14,000 lumen	175	0.193	803	$4.71	$6.66
20,500 lumen	250	0.275	1,144	$6.02	$8.51
36,000 lumen	400	0.430	1,789	$8.37	$11.84
Sodium Vapor					
9,500 lumen	100	0.117	487	$5.60	$7.92
16,000 lumen	150	0.171	711	$6.27	$8.87
22,000 lumen	200	0.228	948	$6.91	$9.77
27,500 lumen	250	0.228	948	$6.91	$9.77
50,000 lumen	400	0.471	1,959	$9.45	$13.37
Decorative Fixture					
Mercury Vapor					
7,000 lumen (Holophane)	175	0.210	874	$5.97	$8.44
7,000 lumen (Town & Country)	175	0.205	853	$5.91	$8.36
7,000 lumen (Gas Replica)	175	0.210	874	$5.97	$8.44
7,000 lumen (Aspen)	175	0.210	874	$5.97	$8.44
Metal Halide					
14,000 lumen (Traditionaire)	175	0.205	853	$5.91	$8.36
14,000 lumen (Granville Acorn)	175	0.210	874	$5.97	$8.44
14,000 lumen (Gas Replica)	175	0.210	874	$5.97	$8.44
Sodium Vapor					
9,500 lumen (Town & Country)	100	0.117	487	$5.52	$7.81
9,500 lumen (Traditionaire)	100	0.117	487	$5.52	$7.81
9,500 lumen (Granville Acorn)	100	0.128	532	$5.76	$8.15
9,500 lumen (Rectilinear)	100	0.117	487	$5.52	$7.81
9,500 lumen (Aspen)	100	0.128	532	$5.76	$8.15
9,500 lumen (Holophane)	100	0.128	532	$5.76	$8.15
9,500 lumen (Gas Replica)	100	0.128	532	$5.76	$8.15
22,000 lumen (Rectilinear)	200	0.246	1,023	$7.32	$10.35
50,000 lumen (Rectilinear)	400	0.471	1,959	$9.77	$13.82

Pole Charges	Pole Type	Current Rate/Pole	Proposed Rate/Pole
Wood			
30 foot	W30	$ 4.78	$6.76
35 foot	W35	$ 4.84	$6.85
40 foot	W40	$ 5.80	$8.20

Customer Owned and Maintained Units	Current per kWh	Proposed per kWh
	4.2793¢	6.0527¢

The monthly kilowatt-hour usage will be mutually agreed upon between the Company and the customer. Where the average monthly usage is less than 150 kWh per point of delivery, the customer shall pay the Company, in addition to the monthly charge, the cost of providing electric service on the basis of time and material plus overhead charges. An estimate of the cost will be submitted for approval before work is carried out.

	Current	Proposed
Late Payment Charge	5%	2.3%

Current Applicability:
Mercury Vapor lighting fixtures will not be installed by the Company after June 1, 2003. As currently installed Mercury Vapor fixtures are retired and/or replaced, they may be replaced with either Metal Halide or Sodium Vapor fixtures as the customer chooses.

This rate schedule is no longer available after December 31, 2006. Potential lighting customers wanting a lighting system installed and maintained by Company can do so via the Outdoor Lighting Equipment agreement (OLE). Potential customers should contact a Company account representative for further information concerning OLE options. This rate schedule terminates December 31, 2026. Customers currently being provided service under this rate schedule can continue being provided service under this rate schedule for the remaining useful life of the facilities, or this rate schedule terminates, whichever occurs first.

Proposed Applicability:
Mercury Vapor lighting fixtures will not be installed by the Company after June 1, 2003.

This rate schedule is no longer available after December 31, 2006. Customers currently being provided service under this rate schedule can continue being provided service under this rate schedule for the remaining useful life of the facilities, or when this rate schedule terminates, whichever occurs first.

Current Type of Service:
The Company will endeavor to replace burned-out lamps within 48 hours after notification by the customer.

Proposed Type of Service:
The Company will endeavor to replace burned-out lamps within three (3) business days after notification by the customer.

Current General Conditions:
(6) When a customer owned lighting unit becomes inoperative, the cost of repair, replacement or removal of the unit will be at the customer's expense.

Proposed General Conditions:
(6) When a customer owned lighting unit becomes inoperative, the cost of repair, replacement or removal of the unit will be at the customer's expense. Upon failure of a customer owned unit, Customer may contact Company to discuss lighting options available with Company owned lighting units.

(8) The customer will be responsible for trimming trees and other vegetation that obstruct the light output from fixture(s) or maintenance access to the facilities. Company shall not be required to pay for obtaining permission to trim or re-trim trees where such trees interfere with supplying electric energy to the system. Customer shall assist Company, if necessary, in obtaining permission to trim trees where Company is unable to obtain such permission through its own best efforts.

Street-lighting Service-Overhead Equivalent-Rate SE
(Electric Tariff Sheet No. 69)

Fixture Description	Lamp Watts	kW/Unit	Annual kWh	Current Rate/Unit	Proposed Rate/Unit
Decorative Fixtures					
Mercury Vapor					
7,000 lumen (Town & Country)	175	0.205	853	$8.13	$11.50
7,000 lumen (Holophane)	175	0.210	874	$8.16	$11.54
7,000 lumen (Gas Replica)	175	0.210	874	$8.16	$11.54
7,000 lumen (Aspen)	175	0.210	874	$8.16	$11.54
Metal Halide					
14,000 lumen (Traditionaire)	175	0.205	853	$8.13	$11.50
14,000 lumen (Granville Acorn)	175	0.210	874	$8.16	$11.54
14,000 lumen (Gas Replica)	175	0.210	874	$8.16	$11.54
Sodium Vapor					
9,500 lumen (Town & Country)	100	0.117	487	$8.80	$12.45
9,500 lumen (Holophane)	100	0.128	532	$8.93	$12.63
9,500 lumen (Rectilinear)	100	0.117	487	$8.80	$12.45
9,500 lumen (Gas Replica)	100	0.128	532	$8.92	$12.62
9,500 lumen (Aspen)	100	0.128	532	$8.92	$12.62
9,500 lumen (Traditionaire)	100	0.117	487	$8.80	$12.45
9,500 lumen (Granville Acorn)	100	0.128	532	$8.92	$12.62
22,000 lumen (Rectilinear)	200	0.246	1,023	$12.69	$17.95
50,000 lumen (Rectilinear)	400	0.471	1,959	$16.88	$23.88
50,000 lumen (Setback)	400	0.471	1,959	$16.88	$23.88
Late Payment Charge				5%	2.3%

Current Applicability:
Mercury Vapor lighting fixtures will not be installed by the Company after June 1, 2003. As currently installed Mercury Vapor fixtures are retired and/or replaced, they may be replaced with either Metal Halide or Sodium Vapor fixtures as the customer chooses.

This rate schedule is no longer available after December 31, 2006. Potential lighting customers wanting a lighting system installed and maintained by Company can do so via the Outdoor Lighting Equipment agreement (OLE). Potential customers should contact a Company account representative for further information concerning OLE options. This rate schedule terminates December 31, 2026. Customers currently being provided service under this rate schedule can continue being provided service under this rate schedule for the remaining useful life of the facilities, or this rate schedule terminates, whichever occurs first.

Proposed Applicability:
Mercury Vapor lighting fixtures will not be installed by the Company after June 1, 2003.

This rate schedule is no longer available after December 31, 2006. Customers currently being provided service under this rate schedule can continue being provided service under this rate schedule for the remaining useful life of the facilities, or when this rate schedule terminates, whichever occurs first.

Current Type of Service:
The Company will endeavor to replace burned-out lamps within 48 hours after notification by the customer.

Proposed Type of Service:
The Company will endeavor to replace burned-out lamps within three (3) business days after notification by the customer.

Current General Conditions:
(6) When a street lighting unit reaches end of life or becomes obsolete and parts cannot be reasonably obtained, the Company can remove the unit at no expense to the customer after notifying the customer. The customer shall be given the opportunity to arrange for another type lighting unit provided by the Company.

Proposed General Conditions:
(6) When a Company owned street lighting unit reaches the end of life or becomes obsolete and parts cannot be reasonably obtained, the Company shall replace lighting unit with an available similar LED lighting unit and/or pole and the Customer shall commence being billed on Rate LED for the available similar lighting unit and pole rate and will enter into a new lighting agreement within 90 days. The terms of service of Rate LED shall commence upon lighting unit and/or pole installation. If within 90 days of replacement the Customer does not enter into a new agreement, the service may be terminated.

(7) The customer will be responsible for trimming trees and other vegetation that obstruct the light output from fixture(s) or maintenance access to the facilities outside of Company distribution reliability trimming. Company shall not be required to pay for obtaining permission to trim or re-trim trees where such trees interfere with supplying electric energy to the system. Customer shall assist Company, if necessary, in obtaining permission to trim trees where Company is unable to obtain such permission through its own best efforts.

Rider X – Line Extension Policy Rider
(Electric Tariff Sheet No. 72)

Current Applicability:
Applicable to electric service supplied in accordance with the provisions of the appropriate rate currently in effect, from the nearest available distribution lines of required type of service when it is necessary to extend such lines.

Proposed Applicability:
Applicable to electric service supplied in accordance with the provisions of the appropriate rate currently in effect, from the nearest available distribution and transmission lines of required type of service when it is necessary to extend such lines or accommodate material changes to a Customer's installation.

Current Extension Plan:
Extensions
When the estimated cost of extending the distribution lines to reach the customer's premise equals or is less than three (3) times the estimated gross annual revenue the Company will make the extension without additional guarantee by the customer over that applicable in the rate, provided the customer establishes credit in a manner satisfactory to the Company.

When the estimated cost of extending the distribution lines to reach the customer's premise exceeds three (3) times the estimated gross annual revenue, the customer may be required to guarantee, for a period of five (5) years, a monthly bill of one (1) percent of the line extension cost for residential service and two (2) percent for non-residential service.

When the term of service or credit have not been established in a manner satisfactory to the Company, the customer may be required to advance the estimated cost of the line extension in either of the above situations. When such advance is made the Company will refund, at the end of each year, for four (4) years, twenty-five (25) percent of the revenues received in any one year up to twenty-five (25) percent of the advance.

Proposed Extension Plan:
Distribution
When the estimated cost of changing or extending the distribution lines to reach the customer's premise is less than $1 million and equals or is less than three (3) times the estimated gross annual revenue the Company will make the extension without additional guarantee by the customer over that applicable in the rate, provided the customer establishes credit in a manner satisfactory to the Company.

NOTICE

When the estimated cost of changing or extending the distribution lines to reach the customer's premise is greater than $1 million or exceeds three (3) times the estimated gross annual revenue, the customer may be required to enter into an agreement with the Company to guarantee, for a period of up to ten (10) years, a monthly bill of one (1) percent of the line extension cost for residential service and two (2) percent for non-residential service.

When the term of service or credit have not been established in a manner satisfactory to the Company, the customer may be required to advance the estimated cost of the line extension in either of the above situations. When such advance is made the Company will refund, at the end of each year, for four (4) years, twenty-five (25) percent of the revenues received in any one year up to twenty-five (25) percent of the advance.

Unless otherwise provided in the rate schedule and/or rider(s) under which the Customer is served, if the Customer requests an amendment to or termination of the agreement before the expiration of the initial term of the agreement, the Customer shall pay to the Company as an early termination charge the sum of the remaining monthly guaranteed bill amounts unless, as determined by the Company, no early termination charge is required.

Transmission
Change to or extension of transmission facilities will follow the Federal Energy Regulatory Commission (FERC) rules. As applicable, the distribution line extension policy above shall apply.

Rider LM – Load Management Rider
(Electric Tariff Sheet No. 73)

Current Off Peak Provision:
The provision is only available as Company demand meters with a programmable time-of-use register or interval data recorders (IDR) are installed on the customer's premise.

(C) When a customer elects the OFF PEAK PROVISION, the monthly customer charge of the applicable Rate DS or DP will be increased by an additional monthly charge of five dollars ($5.00) for each installed time-of-use or interval data recorder meter. In addition, the DEMAND provision of Rate DS or DP shall be modified to the extent that the billing demand shall be based upon the "on peak period," as defined above. However, in no case shall the billing demand be less than the billing demand as determined in accordance with the DEMAND provision of the applicable Rate DS or Rate DP, as modified.

Proposed Off Peak Provision:
The provision is only available as Company demand meters with a programmable time-of-use register or interval data recorders (IDR) or other eligible Company meter are installed on the customer's premise.

(C) When a customer elects the OFF PEAK PROVISION, the monthly customer charge of the applicable Rate DS or DP will be increased by an additional monthly charge of five dollars ($5.00) for each installed time-of-use or interval data recorder or other eligible meter. In addition, the DEMAND provision of Rate DS or DP shall be modified to the extent that the billing demand shall be based upon the "on peak period," as defined above, or fifty (50) percent of the off-peak period whichever is greater. However, in no case shall the billing demand be less than the billing demand as determined in accordance with the DEMAND provision of the applicable Rate DS or Rate DP, as modified.

Rider CEC – Clean Energy Connection Rider (Optional Solar Program)
(Electric Tariff Sheet No. 81)

Proposed New Service:
Any metered Customer account taking service under another Company rate schedule whose account is current is eligible to participate. Eligible Customers may elect a subscription level in 1 kW units representing up to 100% of their previous 12-month total kWh usage. Increases in number of units purchased will be limited to once per rolling 12-month period from the anniversary date of program enrollment, and subject to program availability. Customers who present proof of participation in local, state, or federal assistance are eligible for participation at the low-income pricing provided by this tariff.

Rate MRC – Electric Vehicle Site Make Ready Service
(Electric Tariff Sheet No. 83)

Proposed New Service:
The purpose of this Program is to support adoption of electric vehicles (EVs) and EV charging by customers through revenue credits that defray a portion of EV "make ready" expenses. Make Ready Infrastructure expenses include the cost of investments in the safe and reliable installation of wiring and other upgrades that support EV charging (Make Ready Infrastructure) but exclude the cost of the equipment and charging station (i.e., EVSE) that directly supplies the energy to the EV. The Program also provides fixed incentives to approved homebuilders installing Make Ready Infrastructure into newly constructed homes.

Rate EVSE – Electric Vehicle Service Equipment
(Electric Tariff Sheet No. 84)

Proposed New Service:
This program is available for networked or non-networked Electric Vehicle Service Equipment ("EVSE" or "Charger"). Networked EVSE contains wi-fi, cellular, or other communications capabilities to connect to the internet for communications, data gathering, and charging load management purposes by the Customer and/or the Company. The Company may provide programs and/or services to help Customers manage charging or encourage charging during off-peak hours. Service under this tariff schedule shall require Customer acceptance of Company's terms and conditions specifying the service to be provided. The EVSE System shall comply with the connection requirements in the Company's Electric Service Regulations, Section III and Section IV, Customer's and Company's Installations respectively.

Rider BR - Brown Field Development Rider
(Electric Tariff Sheet No. 85)

Current Availability:
Available to customers locating in a qualified "brownfield" redevelopment area as defined by Kentucky or federal law and served by existing primary service lines. Customers qualifying for service under this rider must enter into a Service Agreement and special contract with the Company. In order to receive service under this rider the special contract must be approved by the Kentucky Public Service Commission.

Proposed Availability:
(The Company proposes to cancel this rider and include Brown Field Development in Rider DIR.)

Rider DIR - Development Incentive Rider
(Electric Tariff Sheet No. 86)

Current Tariff
GENERAL
Under the terms of this Rider, qualifying customers are required to enter into a Special Contract with the Company which Special Contract shall be subject to approval by the Kentucky Public Service Commission. The Development Incentive Rider consists of two separate programs designed to encourage development and/or redevelopment within the Company's service territory. These two programs are the Economic Development Program and the Urban Redevelopment Program. Each of these programs is described below.

PROGRAM DESCRIPTIONS
Economic Development (ED) Program
Available, at the Company's option, to non-residential customers receiving service under the provisions of one of the Company's non-residential tariff schedules. The ED Program is available for load associated with initial permanent service to new establishments, expansion of existing establishments, or new customers in existing establishments who make application to the Company for service under the ED Program of this Rider and the Company approves such application. The new load applicable under the ED Program must be a minimum of 1,000 kW at one delivery point.

To qualify for service under the ED Program, the customer must meet the qualifications as set forth below. Further, the customer must have applied for and received economic assistance from the State or local government or other public agency before the Company will approve a Service Agreement under the ED Program. Where the customer is new to the Company's service area or is an existing customer expanding:

1) the Company would expect the customer employ an additional workforce in the Company's service area of a minimum of twenty-five (25) full-time equivalent (FTE) employees per 1,000 kW of new load. Employment additions must occur following the Company's approval for service under this Rider, and;

2) the Company would expect that the customer's new load would result in capital investment of one million dollars ($1,000,000) per 1,000 kW of new load, provided that such investment is accompanied by a net increase in FTE employees employed by the customer in the Company's service area. This capital investment must occur following the Company's approval for service under this Rider.

The Company may also consider applying the ED Program to an existing customer who, but for economic incentives being provided by the State and/or local government or public agency, would leave the Company's service area. In this event, the customer must agree, at a minimum, to retain the current number of FTE employees.

The ED Program is not available to a new customer which results from a change in ownership of an existing establishment. However, if a change in ownership occurs after the customer enters into a Special Contract for service under the ED Program, the successor customer may be allowed to fulfill the balance of the Special Contract under the ED Program. The ED Program is also not available for renewal of service following interruptions such as equipment failure, temporary plant shutdown, strike, or economic conditions. The ED Program is not available for load shifted from one customer to another within the Company's service area.

Urban Redevelopment (UR) Program
Applicable to new customers locating in an existing building of 25,000 square feet or more, which has been unoccupied and/or remained dormant for a period of two years or more, as determined by the Company. The new customer load must be a minimum of 500 kW at one delivery point. In addition, the requested service necessary to serve the new load must not result in additional investment in distribution or transmission facilities by the Company, excepting that minor alterations in the service supplied which can be accomplished feasibly and economically may be allowed.

The UR Program is not available for renewal of service following interruptions such as equipment failure, temporary plant shutdown, strike, or economic conditions. The UR Program is also not available for load shifted from one establishment to another in the Company's service area. However, if a change of ownership occurs after the customer enters into a Special Contract under the UR Program, the successor customer may be allowed to fulfill the balance of the Special Contract under the UR Program.

NET MONTHLY BILLING
The customer shall comply with all terms of the standard tariff rate under which the customer takes service except that the customer's total bill for electric service, less any rate adjustment rider amounts as shown on the standard service tariff, shall be reduced by up to fifty (50) percent for a period of twelve (12) months. The customer will pay the full amount of the riders so indicated. The customer may request an effective date of the Rider which is no later than twelve (12) months after the Special Contract is approved and signed by the Company. All subsequent billings shall be at the appropriate full standard service tariff rate.

Following the effective date of the Special Contract, the customer must maintain a minimum demand in accordance with the Service Agreement and maintain a monthly average load factor of 40 percent. Failure to do so will result in the customer being billed a minimum bill based on the minimum demand specified in the Service Agreement and a monthly average load factor of 40 percent.

The customer shall continue to take service from the Company at the same or greater demand and usage levels for a period of at least two (2) years following the twelve (12) month incentive period. The customer shall be billed monthly for two (2) years following the twelve (12) month incentive period based on the greater of: (a) its actual monthly demand and usage levels; or (b) its average demand and usage levels during the twelve (12) month incentive period.

TERMS AND CONDITIONS
The Service Agreement shall specify, among other things, the voltage at which the customer will be served, a description of the amount and nature of the new load and the basis on which the customer requests qualification under this Rider. The customer must affirm that the availability of this Rider was a factor in the customer's decision to locate the new load or retain current load in the Company's service area.

For customers entering into a Service Agreement under this Rider due to expansion, the Company may install, at customer's expense, metering equipment necessary to measure the new load to be billed under the provisions of this Rider separate from the customer's existing load which shall be billed under the applicable standard tariff schedule.

The terms of this rider do not prevent the Company from offering different terms under a special contract if the Company deems it appropriate. The Company is not obligated to extend, expand or rearrange its facilities if it determines that existing distribution/transmission facilities are of adequate capacity to serve the customer's load.

The supplying of, and billing for, service and all conditions applying thereto, are subject to the jurisdiction of the Kentucky Public Service Commission, and to the Company's General Terms and Conditions currently in effect, as filed with the Kentucky Public Service Commission.

Proposed Tariff
GENERAL
Under the terms of this Rider, qualifying customers are required to enter into a Special Contract with the Company which Special Contract shall be subject to approval by the Kentucky Public Service Commission. The Development Incentive Rider consists of three separate programs designed to encourage development and/or redevelopment within the Company's service territory. These three programs are the Economic Development Program, the Brownfield Redevelopment Program, and the Urban Redevelopment Program. Each of these programs is described below.

PROGRAM DESCRIPTIONS
Economic Development (ED) Program
Available, at the Company's option, to non-residential customers receiving service under the provisions of one of the Company's non-residential tariff schedules. The ED Program is available for load associated with initial permanent service to new establishments, expansion of existing establishments, or new customers in existing establishments who make application to the Company for service under the ED Program of this Rider and the Company approves such application. The new load applicable under the ED Program must be a minimum of 1,000 kW at one delivery point. Following the effective date of the Special Contract, the customer must maintain a minimum demand in accordance with the Special Contract and maintain a monthly average load factor of 35 percent. Failure to do so will result in the customer being billed a minimum bill based on the minimum demand specified in the Special Contract and a monthly average load factor of 35 percent.

To qualify for service under the ED Program, the customer must meet the qualifications as set forth below. Further, the customer must have applied for and received economic assistance from the State or local government or other public agency before the Company will approve a Special Contract under the ED Program, and the customer must affirm that the availability of this Rider was a factor in the customer's decision to locate the new load in the Company's service territory. Where the customer is new to the Company's service area or is an existing customer expanding, the Customer must meet at least one of the following:

1) employ an additional workforce in the Company's service area of a minimum of ten (10) additional full-time equivalent (FTE) employees. Employment additions must occur following the Company's approval for service under this Rider and prior to the start of incentives under this rider, or;

2) minimum capital investment of one million dollars ($1,000,000) at the customer's facility within the Company's service area. This capital investment must occur following the Company's approval for service under this Rider and prior to the start of incentives under this rider.

The Company may also consider applying the ED Program to an existing customer who, but for economic incentives being provided by the State and/or local government or public agency, would leave the Company's service area. In this event, the customer must agree, at a minimum, to retain the current number of FTE employees for the term of the Special Contract.

Brownfield Redevelopment (BR) Program
Available to customers locating in a qualified "brownfield" redevelopment area as defined by Kentucky or federal law and served by existing primary service lines. Customers qualifying for service under this program must enter into a Service Agreement and special contract with the Company. In order to receive service under this rider the special contract must be approved by the Kentucky Public Service Commission.

Urban Redevelopment (UR) Program
Applicable to new customers locating in an existing building of 25,000 square feet or more, which has been unoccupied and/or remained dormant for a period of two years or more, as determined by the Company. The new customer load must be a minimum of 500 kW at one delivery point. In addition, the requested service necessary to serve the new load must not result in additional investment in distribution or transmission facilities by the Company, excepting that minor alterations in the service supplied which can be accomplished feasibly and economically may be allowed.

NET MONTHLY BILLING
The customer shall comply with all terms of the standard tariff rate under which the customer takes service. The Company will provide a monthly bill reduction up to thirty (30) percent for a period of up to sixty (60) months. The dollar amount of bill reduction will be derived by applying the agreed percentage to the customer's bill excluding excess facility charges, applicable taxes, base fuel, and any rate adjustment rider amounts as shown on the standard service tariff. The customer will pay the full amount of the riders so indicated. As specified in the Special Contract, the percent reduction may be different annually. The Special Contract may also specify a maximum dollar credit amount.

In no event shall the expected incremental revenues derived from the discounted rate charges for serving the Customer's new or increased load be less than the Company's incremental cost of serving the customer over the length of the minimum term of the agreement.

The customer may request an effective date of the Rider which is no later than thirty-six (36) months after the Special Contract is approved and signed by the Company. All subsequent billings shall be at the appropriate full standard service tariff rate.

EVALUATION CRITERIA
The percentage discount will be determined on an individual Customer basis given evaluation of the following criteria as available.

1. Peak monthly demand
2. Average monthly load factor
3. Interruptible characteristics
4. Cost to serve
5. New full-time equivalent employees
6. New average wage versus county average wage
7. New capital investment
8. County unemployment rate
9. Existing customer attributes (annual bill, current full time equivalent employees)
10. Regional economic multipliers

VERIFICATION OF PERFORMANCE
The Company will monitor annually the awarding of all contracts to ensure the Customer fulfills all terms and conditions of the contract associated with the award. Customer agrees to comply with reasonable requests from the Company for information in this regard. Nonfulfillment of contract terms and conditions is grounds for reopening and reevaluation of all contract terms and conditions, up to and including termination of the agreement. Confidentiality shall be maintained regarding the terms and conditions of any completed contract as well as all Customer negotiations, successful or otherwise.

TERMS AND CONDITIONS
These Programs are not available to a new customer which results from a change in ownership of an existing establishment. However, if a change in ownership occurs after the customer enters into a Special Contract for service under this Rider, the successor customer may be allowed to fulfill the balance of the Special Contract under this Rider. This Rider is also not available for renewal of service following interruptions such as equipment failure, temporary plant shutdown, strike, or economic conditions. This Rider is not available for load shifted from one customer to another within the Company's service area.

The customer must enter into a Special Contract with the Company which shall specify, among other things, the voltage at which the customer will be served, a description of the amount and nature of the new load and the basis on which the customer requests qualification for this Rider.

The customer shall continue to take service from the Company at the same or greater demand and usage levels for a period of at least two (2) years following the incentive period. The customer shall be billed monthly for two (2) years following the incentive period based on the greater of: (a) its actual monthly demand and usage levels; or (b) its average demand and usage levels during the incentive period.

If the Customer ceases the operations for which Rider DIR was originally approved, the Company will require that the Customer repay the Rider DIR reductions received according to the following schedule based on when the operations cease:

Years 1 to 5:	100%
Year 6:	80%
Year 7:	60%
Year 8:	40%
Year 9:	20%
Year 10:	10%

For customers entering into a Special Contract under this Rider due to expansion, the Company may install, at customer's expense, metering equipment necessary to measure the new load to be billed under the provisions of this Rider separate from the customer's existing load which shall be billed under the applicable standard tariff schedule.

The terms of this rider do not prevent the Company from offering different terms under a special contract if the Company deems it appropriate. The Company is not obligated to extend, expand or rearrange its facilities if it determines that existing distribution/transmission facilities are of adequate capacity to serve the customer's load.

SERVICE REGULATIONS
The supplying of, and billing for, service and all conditions applying thereto, are subject to the jurisdiction of the Kentucky Public Service Commission, and to the Company's General Terms and Conditions currently in effect, as filed with the Kentucky Public Service Commission.

Rider GSA – Green Source Advantage
(Electric Tariff Sheet No. 87)

Current Application Process and GSA Service Agreement:

To participate in the GSA Program, a Customer must submit an application to the Company during a GSA Program enrollment window, as described on the Company's Program website, identifying an annual amount of renewable capacity to be developed on behalf of Customer. The Customer may apply for renewable generation capacity up to 125% of the Customer's aggregate Maximum Annual Demand for eligible Customer service location(s) within the Duke Energy Kentucky service territory. The Maximum Annual Demand shall be the sum of each locations kilowatts derived from the Company's demand meter for the fifteen minute period of greatest use adjusted for power factor as provided in each locations applicable tariff sheet.

NOTICE

Proposed Application Process and GSA Service Agreement:
To participate in the GSA Program, a Customer must submit an application to the Company during a GSA Program enrollment window, as described on the Company's Program website, identifying an annual amount of renewable capacity to be developed on behalf of Customer. The Customer may apply for renewable generation capacity up to 100% of the Customer's Annual Energy consumption (kWh) for eligible Customer service location(s) within the Duke Energy Kentucky service territory. The Annual Energy consumption shall be the sum of each locations kilowatt hours derived from the Company's meter and adjusted as applicable for each locations applicable tariff sheet.

	Current	Proposed
Late Payment Charge	5%	2.3%

Rider GP – Duke Energy's GoGREEN Kentucky
Green Power / Carbon Offset Rider
(Electric Tariff Sheet No. 88)

Current Tariff:
DUKE ENERGY'S GoGREEN KENTUCKY
GREEN POWER / CARBON OFFSET RIDER

APPLICABILITY
Applicable to all customers who wish to purchase GoGreen units from the Company-sponsored GoGreen program and who enter a service agreement with the Company.

DEFINITION OF GREEN POWER
Green Power includes energy generated from renewable and/or environmentally friendly sources, including:

Wind, Solar Photovoltaic, Biomass Co-firing of Agricultural Crops, Hydro – as certified by the Low Impact Hydro Institute, Incremental Improvements in Large Scale Hydro, Coal Mine Methane, Landfill Gas, Biogas Digesters, Biomass Co-firing of All Woody Waste including mill residue, but excluding painted or treated lumber.

The GoGreen Program includes the purchase of Renewable Energy Certificates (RECs) from the sources described above.

NET MONTHLY BILL
Customers who participate under this rider will be billed for electric service under all applicable tariffs including all applicable riders.

Green Power purchased under this rider, will be billed at the applicable Green Power rate times the number of 100 kWh blocks the customer has agreed to purchase per month.

The Green Power rate shall be $1.00 per 100 kWh block with a minimum monthly purchase of two 100 kWh blocks.

TERMS AND CONDITIONS
1. The customer shall enter into a service agreement with Company that shall specify the number of kWh blocks to be purchased monthly and the corresponding rates(s) per unit. The Customer shall give Company thirty (30) days notice prior to cancellation of participation in this rider.

2. Funds from the GoGreen Rate will be used to purchase RECs from renewable and environmentally friendly sources as described in the DEFINITION OF GREEN POWER section and for customer education, marketing, and costs of the Green Power Program.

3. Renewable Energy Certificate (REC) shall mean tradable units that represent the commodity formed by unbundling the environmental attributes of a unit of renewable or environmentally friendly energy from the underlying electricity. One REC would be equivalent to the environmental attributes of one MWH of electricity from a renewable or environmentally friendly generation source.

4. Company may obtain RECs from purchased power, company owned generation, or third party brokers purchased with funds collected from this rider.

5. Company reserves the right to terminate the Rider or revise the pricing or minimum purchase amount of the Rider after giving 60 days notice to the Kentucky Public Service Commission.

The supplying of, and billing for, service and all conditions applying thereto, are subject to the jurisdiction of the Kentucky Public Service Commission, and to the Company's Service Regulations, as filed with the Kentucky Public Service Commission.

Proposed Tariff:
GoGREEN KENTUCKY RIDER

APPLICABILITY
Applicable to all customers who wish to purchase GoGreen units from the Company-sponsored GoGreen program and who enter a service agreement with the Company.

DEFINITION OF GOGREENUNITS
GoGreen units include renewable attributes generated from renewable and/or environmentally friendly sources, including:

Wind, Solar Photovoltaic, Biomass Co-firing of Agricultural Crops and all energy crops, Hydro – as certified by the Low Impact Hydro Institute, Incremental Improvements in Large Scale Hydro, Coal Mine Methane, Landfill Gas, Biogas Digesters, Biomass Co-firing of All Woody Waste including mill residue, but excluding painted or treated lumber.

The GoGreen Program includes the purchase of Renewable Energy Certificates (RECs) from the sources described above.

GOGREEN RATE

Rates RS and Rate RS-TOU-CPP and Rate DS (customers with monthly demand <=15 kW):

For all GoGreen units ……..……..……..…………..…$1.00 per unit per month

Minimum purchase is two (2) 100 kWh units. Additional purchases to be made in 100 kWh unit increments.

Rate DS (customers with monthly demand > 15 kW) and Rates DT, DP, and TT:
Individually calculated price for GoGreen units per service agreement.

All Other Rates:
Can choose to participate in either offering above.

NET MONTHLY BILL
Customers who participate under this rider will be billed for electric service under all standard applicable tariffs, including all applicable riders.

The purchase of GoGreen units, under this Rider, will be billed at the applicable GoGreen rate times the number of GoGreen units the customer has agreed to purchase per month. The customer's monthly bill will consist of the sum of all charges billed at the applicable rate tariffs, including all applicable riders, and the agreed to GoGreen units billed at the applicable GoGreen Rate.

When the GoGreen Rate is individually calculated per service agreement, Duke Energy Kentucky will bill such customer separately for GoGreen units.

TERMS AND CONDITIONS
1. The customer shall enter into a service agreement with Company that shall specify the amount of GoGreen units and price of GoGreen units to be purchased monthly. The Customer shall give Company thirty (30) days notice prior to cancellation of participation in this rider.

2. Customers entering into service agreements for individually calculated GoGreen Rate must demonstrate credit-worthiness.

3. Funds from the GoGreen Rate will be used to purchase RECs from renewable and environmentally friendly sources as described in the DEFINITION OF GOGREEN UNITS section and for customer education, marketing, and costs of the GoGreen Kentucky Program.

4. RECs shall mean tradable units that represent the commodity formed by unbundling the environmental attributes of a unit of renewable or environmentally friendly energy from the underlying electricity. One REC would be equivalent to the environmental attributes of one MWH of electricity from a renewable or environmentally friendly generation source.

5. Company may obtain RECs from purchased power, company owned generation, or third party brokers purchased with funds collected from this rider. Company may transfer RECs at the prevailing wholesale market prices to and from third parties, including affiliated companies.

6. Company reserves the right to terminate the Rider or revise the pricing or minimum purchase amount of the Rider after giving sixty (60) days notice to the Kentucky Public Service Commission, unless the change is a decrease in pricing, in which case no advance notice would be required.

SERVICE REGULATIONS
The supplying of, and billing for, service and all conditions applying thereto, are subject to the jurisdiction of the Kentucky Public Service Commission, and to the Company's Service Regulations, as filed with the Kentucky Public Service Commission

Charge for Reconnection of Service
(Electric Tariff Sheet No. 91)

	Current Rate	Proposed Rate
Reconnections that can be accomplished remotely	$5.88	$5.60

Distribution Pole Attachments - Rate DPA
(Electric Tariff Sheet No. 92)

	Current Rate	Proposed Rate
Two-user pole annual rental per foot	$8.59	$9.99
Three-user pole annual rental per foot	$7.26	$8.61

Local Government Fee
(Electric Tariff Sheet No. 95)

Current Tariff:
APPLICABLE TO ALL RATE SCHEDULES

There shall be added to the customer's bill, listed as a separate item, an amount equal to the fee now or hereafter imposed by local legislative authorities, whether by ordinance, franchise or other means. Such amount shall be added exclusively to bills of customers receiving service within the territorial limits of the authority imposing the fee.

Where more than one such fee is imposed, each of the charges applicable to each customer shall be added to the customer's bill and listed separately.

Where the local legislative authority imposes a flat, fixed amount on the Company, the fee applied to the bills of customers receiving service within the territorial boundaries of that authority, shall be in the form of a flat dollar amount.

The amount of such fee added to the customer's bill shall be determined in accordance with the terms of the ordinance, franchise or other directive agreed to by the Company.

Proposed Tariff:
APPLICABILITY
This tariff sheet is applicable to all rate schedules.

DESCRIPTION
There shall be added to the customer's bill, listed as a separate item, an amount equal to the fee(s) or incremental cost(s) now or hereafter imposed by cities, or other local legislative authorities in the Company's certified territory (Public Authorities), whether by ordinance, franchise or other means. Such amount shall be added exclusively to bills of customers receiving service within the territorial limits of the authority imposing the fee(s) or incremental cost(s). Such charge to customer bills shall include any and all incremental costs incurred by the Company as a direct result of the local legislative authority's ordinance, franchise or other means including but not limited to distribution, transmission, generation, and other construction and facility costs (Incremental Local Investments) that are outside the Company's regular system-wide construction plans absent the local legislative authority's ordinance, franchise, or other means.

Where more than one such fee or incremental cost is imposed, each of the charges applicable to each customer shall be added to the customer's bill and listed separately.

Where the local legislative authority imposes a flat, fixed amount on the Company, the charge applied to the bills of customers receiving service within the territorial boundaries of that authority, shall be in the form of a flat dollar amount.

The amount of such charge(s) added to the customer's bill shall be equal to the amount(s) imposed by terms of the ordinance, franchise or other directive agreed to by the Company, or otherwise ordered by the Kentucky Public Service Commission.

Electricity Emergency Procedures for Long-Term Fuel Shortages
(Electric Tariff Sheet No. 98)

Current Applicability:
In the event of an energy emergency which necessitates curtailment of electricity consumption, Duke Energy Kentucky, Inc. and consumers of electric energy supplied by the Company shall take actions set forth herein, except where the Kentucky Public Service Commission (Commission) or other authority having jurisdiction in the matter orders otherwise.

Proposed Applicability:
(The Company proposes to cancel this tariff and include Long-Term Fuel Shortages in Emergency Electric Procedures, Electric Tariff Sheet No. 100.)

Real Time Pricing Program- Rate RTP
(Electric Tariff Sheet No. 99)

	Current Rate	Proposed Rate
Energy Delivery Charge (Credit) per kWh from Customer Base Load		
Secondary Service	1.8119¢	2.4809¢
Primary Service	1.4956¢	2.0898¢
Transmission Service	0.6575¢	0.8139¢
Program Charge per billing period	$183.00	$183.00

Emergency Electric Procedures
(Electric Tariff Sheet No. 100)

Proposed Long-Term Fuel Shortage or Severe Weather
Electricity emergency procedures may be necessary if there is a shortage in the electric energy supply to meet the requirements of consumers of electric energy in the service area of the Company. The procedures set forth the actions to be taken by the Company and consumers of electric energy in the event of a long-term fuel shortage for electric generation or severe weather jeopardizing electric service to the Company's customers.

In the event of a long-term fuel shortage such as a situation resulting from a coal strike, the steps above under sections III and IV may be utilized as permitted by contractual commitments or by order of the regulatory authority having jurisdiction such as PJM or NERC.

Rider ILIC – Incremental Local Investment Charge
(Electric Tariff Sheet No. 126)

Proposed Applicability:
There shall be a monthly surcharge added to customer bills to recover any incremental costs incurred by the Company as a direct result of a city or other local legislative authority's (Public Authority) ordinance, franchise or other directive including but not limited to distribution, transmission, generation, and other construction and facility costs (Incremental Local Investments) that are outside the Company's regular system-wide construction plans absent the Public Authority's ordinance, franchise, or other directive. The Kentucky Public Service Commission shall determine whether such a charge shall be included on all customer bills or only on those customers within the boundaries of the Public Authority imposing such costs.

The foregoing rates reflect a proposed increase in electric revenues of approximately $75,176,777 or 17.84% over current total electric revenues to Duke Energy Kentucky. The estimated amount of increase per customer class is as follows:

	Total Increase ($)	Total Increase (%)
Rate RS – Residential Service:	$37,409,050	21.2%
Rate DS – Service at Distribution Voltage	$19,283,571	15.9%
Rate DT-Time of Day Rate for Service at Distribution Voltage	$15,504,529	15.7%
Rate EH – Optional Rate for Electric Space Heating	$265,229	15.9%
Rate SP – Seasonal Sports Service	$4,311	16.0%
Rate GS-FL – General Service Rate for Small Fixed Loads	$128,540	16.0%
Rate DP – Service at Primary Distribution Voltage	$171,805	13.1%
Rate TT, Time-of-Day Rate for Service at Transmission Voltage	$1,512,465	10.1%
Rate SL – Street Lighting Service	$380,192	30.3%
Rate TL – Traffic Lighting Service	$7,395	7.4%
Rate UOLS – Unmetered Outdoor Lighting Electric Service	$126,844	31.2%
Rate NSU – Street Lighting Service for Non-Standard Units	$26,526	34.8%
Rate SC – Street Lighting Service – Customer Owned	$1,593	31.2%
Rate SE – Street Lighting Service – Overhead Equivalent	$80,613	34.5%
Rate LED – Street Lighting Service – LED Outdoor Lighting	-$6,479	-33.0%
Rate RTP – Experimental Real Time Pricing Program	$87,178	7.4%
Interdepartmental	$12,367	17.2%
Special Contracts	$145,895	16.0%
Reconnection Charges	-$2,766	-4.8%
Rate DPA - Pole and Line Attachments	$37,919	17.5%

The average monthly bill for each customer class to which the proposed rates will apply will increase approximately as follows:

	Average kWh/Bill	Monthly Increase ($)	Percent Increase (%)
Rate RS – Residential Service:	921	$23.08	21.2%
Rate DS – Service at Distribution Voltage	7,333	$143.15	15.9%
Rate DT-Time of Day Rate for Service at Distribution Voltage	575,416	$5,157.84	12.0%
Rate EH – Optional Rate for Electric Space Heating	26,250	$352.54	15.9%
Rate SP – Seasonal Sports Service	1,242	$26.06	19.0%
Rate GS-FL – General Service Rate for Small Fixed Loads	590	$9.33	16.5%
Rate DP – Service at Primary Distribution Voltage	57,693	$797.81	13.2%
Rate TT, Time-of-Day Rate for Service at Transmission Voltage	1,234,076	$11,194.52	10.1%
Rate SL – Street Lighting Service *	77	$3.77	30.4%
Rate TL – Traffic Lighting Service *	14	$0.07	7.4%
Rate UOLS – Unmetered Outdoor Lighting Electric Service *	66	$1.15	31.0%
Rate NSU – Street Lighting Service for Non-Standard Units*	49	$3.24	34.7%
Rate SC – Street Lighting Service – Customer Owned *	44	$0.78	31.6%
Rate SE – Street Lighting Service – Overhead Equivalent *	60	$3.41	34.6%
Rate LED – Street Lighting Service – Led Outdoor Lighting *	24	-$5.63	-33.0%
Rate RTP – Experimental Real Time Pricing Program	293,893	$208.77	1.0%
Interdepartmental	N/A	$1,030.58	17.2%
Reconnection Charges (per remote reconnection)	N/A	-$0.28	-4.8%
Rate DPA - Pole and Line Attachments (per attachment)	N/A	$0.12	17.4%

*For lighting schedules, values represent average monthly kWh usage per fixture.

The rates contained in this notice are the rates proposed by Duke Energy Kentucky; however, the Kentucky Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice. Such action may result in rates for consumers other than the rates in this notice.

Any corporation, association, body politic or person with a substantial interest in the matter may, by written request within thirty (30) days after publication of this notice of the proposed rate changes, request leave to intervene; intervention may be granted beyond the thirty (30) day period for good cause shown. Such motion shall be submitted to the Kentucky Public Service Commission, P. O. Box 615, 211 Sower Boulevard, Frankfort, Kentucky 40602-0615, and shall set forth the grounds for the request including the status and interest of the party. If the Commission does not receive a written request for intervention within thirty (30) days of the initial publication the Commission may take final action on the application.

Intervenors may obtain copies of the application and other filings made by the Company by requesting same through email at DEKInquiries@duke-energy.com or by telephone at (513) 287-4366. A copy of the application and other filings made by the Company is available for public inspection through the Commission's website at http://psc.ky.gov, at the Commission's office at 211 Sower Boulevard, Frankfort, Kentucky, Monday through Friday, 8:00 am. To 4:30 p.m., and at the following Company offices: 1262 Cox Road, Erlanger, Kentucky 41018. Comments regarding the application may be submitted to the Public Service Commission through its website, or by mail at the following Commission address.

.

For further information contact:

PUBLIC SERVICE COMMISSION
COMMONWEALTH OF KENTUCKY
P. O. BOX 615
211 SOWER BOULEVARD
FRANKFORT, KENTUCKY 40602-0615
(502) 564-3940

DUKE ENERGY KENTUCKY
1262 COX ROAD
ERLANGER, KENTUCKY 41018
(513) 287-4366

List of Newspapers in Duke Energy Kentucky Territory

Falmouth Outlook
Kentucky Enquirer
Gallatin County News
Grant County News

807 KAR 5:001, SECTION 16(2)

Description of Filing Requirement:

Notice of intent. A utility with gross annual revenues greater than $5,000,000 shall notify the commission in writing of its intent to file a rate application at least thirty (30) days, but not more than sixty (60) days, prior to filing its application.

(a) The notice of intent shall state if the rate application will be supported by a historical test period or a fully forecasted test period.

(b) Upon filing the notice of intent, an application may be made to the commission for permission to use an abbreviated form of newspaper notice of proposed rate increases provided the notice includes a coupon that may be used to obtain a copy from the applicant of the full schedule of increases or rate changes.

(c) Upon filing the notice of intent with the commission, the applicant shall mail to the Attorney General's Office of Rate Intervention a copy of the notice of intent or send by electronic mail in a portable document format, to rateintervention@ag.ky.gov.

Response:

See Duke Energy Kentucky’s response to Filing Requirement KRS 278.180 [Tab 1].

Sponsoring Witness:

Amy B. Spiller

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(3)

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807 KAR 5:001, SECTION 16(3)

Description of Filing Requirement:

Notice given pursuant to Section 17 of this administrative regulation shall satisfy the requirements of 807 KAR 5:051, Section 2.

Response:

Notice given pursuant to 807 KAR 5:001, Section 17 satisfies the requirements of 807 KAR 5:051, Section 2. A copy of the customer notice is attached in response to Filing Requirement, 807 KAR 5:001, Section 16(1)(b)(5) [Tab 12].

Sponsoring Witness:

Amy B. Spiller

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(6)(a)

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807 KAR 5:001, SECTION 16(6)(a)

Description of Filing Requirement:

The financial data for the forecasted period shall be presented in the form of pro forma adjustments to the base period.

Response:

See Schedules D-2.1 through D-2.15 located in Schedule Book.

Witness Responsible:

Grady “Tripp” S. Carpenter

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(6)(b)

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807 KAR 5:001, SECTION 16(6)(b)

Description of Filing Requirement:

Forecasted adjustments shall be limited to the twelve (12) months immediately following the suspension period.

Response:

See Schedules D-2.16 through D-2.31 for adjustments to the forecasted period located in Schedule Book. These adjustments are limited to the twelve (12) months immediately following the suspension period.

Witness Responsible:

Grady “Tripp” S. Carpenter – Schedule D-2.16
Lisa D. Steinkuhl – Schedules D-2.17 thru D-2.23, D-2.25 thru D-2.31
Huyen C. Dang – Schedule D-2.24

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(6)(c)

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807 KAR 5:001, SECTION 16(6)(c)

Description of Filing Requirement:

Capitalization and net investment rate base shall be based on a thirteen (13) month average for the forecasted period.

Response:

Capitalization and Net Investment Rate Base for the Forecasted Period are based on a thirteen-month average.

Witness Responsible:

Lisa D. Steinkuhl

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(6)(d)

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807 KAR 5:001, SECTION 16(6)(d)

Description of Filing Requirement:

After an application based on a forecasted test period is filed, there shall be no revisions to the forecast, except for the correction of mathematical errors, unless the revisions reflect statutory or regulatory enactments that could not, with reasonable diligence, have been included in the forecast on the date it was filed. There shall be no revisions filed within thirty (30) days of a scheduled hearing on the rate application.

Response:

The Company will comply with this requirement.

Witness Responsible:

Grady “Tripp” S. Carpenter

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(6)(e)

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807 KAR 5:001, SECTION 16(6)(e)

Description of Filing Requirement:

The commission may require the utility to prepare an alternative forecast based on a reasonable number of changes in the variables, assumptions, and other factors used as the basis for the utility's forecast.

Response:

The Company will prepare an alternative forecast if requested by the Commission.

Witness Responsible:

Grady “Tripp” S. Carpenter

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(6)(f)

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807 KAR 5:001, SECTION 16(6)(f)

Description of Filing Requirement:

The utility shall provide a reconciliation of the rate base and capital use to determine its revenue requirements.

Response:

See attached.

Witness Responsible:

Lisa D. Steinkuhl

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2022-00372
RECONCILIATION OF CAPITALIZATION AND RATE BASE
THIRTEEN MONTH AVERAGE BALANCE ENDING JUNE 30, 2024

FR 16(6)(f) Forecast Period
PAGE 1 OF 3
WITNESS RESPONSIBLE:
L. D. STEINKUHL

Line No.	Description	Source	Amount
1	Capitalization Allocated to Electric Operations	Page 2 of 3	1,206,071,964
2	Adjustments to Plant in Service	Sch. B-2.2 & B-3.1	(52,149,057)
3	Assets per Books not included in Rate Base:		
4	Other Property and Investments	Schedule B-8	(10,659,171)
5	CWIP	Sch. B-4	(33,199,605)
6	Cash	Schedule B-8	(5,737,739)
7	Other Current Assets	Schedule B-8	(4,985,024)
8	Other Regulatory Assets	Schedule B-8	(107,917,270)
9	Other Deferred Debits	Schedule B-8	(46,074,976)
10	Subtotal		(208,573,785)
11	Liabilities per Books not included in Rate Base:		
12	Other Current liabilities	Schedule B-8	53,211,843
13	Other Non-current liabilities	Schedule B-8	33,549,935
14	Deferred Credits	Schedule B-8	113,069,748
15	Subtotal		199,831,526
16	Items included in Rate Base:		
17	Cash Working Capital Formula	Sch.B-5	5,424,742
18	Depreciation adjustment not included in capitalization	Sch. D-2.24	13,982,274
19	Capitalization / Rate Base Differences		12,087,202
20	Subtotal		31,494,217
21	Total Variance		(29,397,099)
22	Electric Rate Base	Schedule B-1	1,176,674,865

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2022-00372
RECONCILIATION OF CAPITALIZATION AND RATE BASE
THIRTEEN MONTH AVERAGE BALANCE ENDING JUNE 30, 2024

FR 16(6)(f) Forecast Period
PAGE 2 OF 3
WITNESS RESPONSIBLE:
L. D. STEINKUHL

Line No.	Description		Capitalization Total	Capitalization Electric
1	Total Forecasted Period Capitalization	(1)	1,839,136,542	
2				
3	Less: Gas Non-jurisdictional Rate Base	(2)	130,118	
4	Electric Non-jurisdictional Rate Base	(2)	(2,772,366)	
5	Non-jurisdictional Rate Base	(2)	(19,793,603)	
6				
7	Jurisdictional Capitalization		1,861,572,393	
8				
9	Electric Jurisdictional Rate Base Allocation %	(2)	64.614%	1,202,836,386
10				
11	Plus: Jurisdictional Electric ITC	(3)		3,235,578
12				
13	Total Allocated Capitalization			1,206,071,964

Notes:
(1) Schedule J-1, page 1.
(2) Page 3 of 3.
(3) Schedule B-6, page 1.

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2022-00372
RECONCILIATION OF CAPITALIZATION AND RATE BASE
THIRTEEN MONTH AVERAGE BALANCE ENDING JUNE 30, 2024

FR 16(6)(f) Forecast Period
PAGE 3 OF 3
WITNESS RESPONSIBLE:
L. D. STEINKUHL

Line No.	Description	Schedule Reference	Total Company	Gas Excl. of Facilities Devoted to Other Than DE-Kentucky Custs.	Gas Non-Juris.	Electric Jurisdictional	Electric Non-Juris.	Non-Jurisdictional
1	Total Utility Plant in Service (Accts 101 & 106) (B)	Sch B-2, (C)	3,154,586,870	907,524,393	0	2,247,062,477	0	0
2								
3	Additions:							
4	Construction Work in Progress (Account 107)	Sch B-4, (C)	101,375,767	68,176,162		33,199,605	0	0
5								
6	Fuel Inventory	Sch B-5	26,060,565	0	0	26,060,565	0	0
7								
8	Materials & Supplies -							
9	Propane Inventory (Account 151) (B)	WPB-5.1b	0	0	0	0	0	0
10	Other Material and Supplies (Accts. 154 & 163) (B)	WPB-5.1c	18,994,569	318,780	0	18,675,789	0	0
11	Total Materials & Supplies		18,994,569	318,780	0	18,675,789	0	0
12								
13	Gas Stored Underground (Account 164) (B)	WPB-5.1f	7,060,122	7,060,122	0	0	0	0
14								
15	Prepayments (Account 165) (B)	WPB-5.1e	1,131,657	37,145	133,745	497,555	463,212	0
16								
17	Emission Allowances (Account 158)	WPB-5.1i	0	0	0	0	0	0
18								
19	Cash Working Capital Allowance	WPB-5.1a	5,424,742	0	0	5,424,742	0	0
20								
21	Other Rate Base Items	WPF-6a	0	0	0	0	0	0
22	Total Additions		160,047,422	75,592,209	133,745	83,858,256	463,212	0
23								
24	Deductions:							
25	Reserve for Accumulated Depreciation (Acct 108) (B)	Sch B-3.2, (C)	1,056,876,937	207,022,272	0	849,854,665 (A)	0	0
26								
27	Accum. Deferred Income Taxes (Accts 190, 282, & 283) (B)	Sch B-6, WPB-6a	310,453,309	77,799,520	0	212,860,186	0	19,793,603
28								
29	Customer Advances for Construction (Account 252)	WPB-6a	1,855,906	1,855,906	0	0	0	0
30								
31	Total Regulatory Liability - Excess Deferred Taxes	Sch B-6	81,326,750	30,007,416	0	51,319,334	0	0
32								
33	Investment Tax Credits	Sch B-6	3,239,205	0	3,627	0	3,235,578	0
34	Total Deductions		1,453,752,107	316,685,114	3,627	1,114,034,185	3,235,578	19,793,603
35								
36	Net Original Cost Rate Base		1,860,882,185	666,431,488	130,118	1,216,886,548	(2,772,366)	(19,793,603)
37								
38	Jurisdictional Rate Base Ratio		100.000%	35.813%	0.007%	65.393%	-0.149%	-1.064%
39								
40	Jurisdictional Rate Base Ratio - Excluding Non-Jurisdictional		100.000%	35.386%		64.614%		

Notes:
(A) Does not include depreciation annualization adjustment per Commission precedent.
(B) Adjusted for non-jurisdictional gas plant.
(C) Company records.

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(a)

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807 KAR 5:001, SECTION 16(7)(a)

Description of Filing Requirement:

The written testimony of each witness the utility proposes to use to support its application, which shall include testimony from the utility's chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program.

Response:

All testimony is provided under separate cover. Also, please see the Direct Testimony of Amy B. Spiller, Duke Energy Kentucky's chief officer in charge of operations, for an overview discussion of efficiency and productivity improvements.

Sponsoring Witness:

All Witnesses

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(b)

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807 KAR 5:001, SECTION 16(7)(b)

Description of Filing Requirement:

The utility's most recent capital construction budget containing at minimum a three (3) year forecast of construction expenditures.

Response:

See attached.

Sponsoring Witnesses:

Grady “Tripp” S. Carpenter
Nick J. Melillo
William C. Luke

Duke Energy Kentucky, Inc.
Case No. 2022-00372
Capital Expenditure Budget
Years 2022 - 2024

Line No.	Project ID/Description	CWIP Balance @ 12/31/21	Projected Expenditures (includes AFUDC) 2022	2023	2024
1	NORMAL RECURRING CONSTRUCTION	77,984,860	84,574,922	112,464,584	90,300,358
2					
3	DCAPINC - Taylor Mill Sub - DKY2135 -Tier 1	0	0	1,232,183	12,142,532
4	M190309 - Hebron-Oakbrook-Install 69 kV Circuit	0	195,652	6,480,644	13,078,184
5	WD301205 WGS CT3 Overhaul No 3	0	0	0	16,868,503
6					
7	TOTAL	77,984,860	84,770,574	120,177,412	132,389,577

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(c)

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807 KAR 5:001, SECTION 16(7)(c)

Description of Filing Requirement:

A complete description, which may be filed in written testimony form, of all factors used in preparing the utility's forecast period. All econometric models, variables, assumptions, escalation factors, contingency provisions, and changes in activity levels shall be quantified, explained, and properly supported.

Response:

Attached are a copy of the Confidential Budget Guidelines for 2022 and a summary of the assumptions that were used in developing the projected data in the base and forecasted test periods. Descriptions of the factors used in preparing the forecasted test period are also incorporated in each witness' pre-filed testimony.

All confidential information is being provided under seal pursuant to a Petition for Confidential Treatment that is being filed simultaneously with this Application.

Sponsoring Witness:

Grady "Tripp" S. Carpenter

CONFIDENTIAL PROPRIETARY TRADE SECRET

FR 16(7)(c) CONFIDENTIAL ATTACHMENT

BEING FILED UNDER SEAL

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(d)

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807 KAR 5:001, SECTION 16(7)(d)

Description of Filing Requirement:

The utility's annual and monthly budget for the twelve (12) months preceding the Filing Date, the Base Period, and Forecasted Period.

Response:

See the attached for the Company's official 202, 20221 and 2023 operating budgets which include the 12 months preceding the Filing Date (December 2021 - November 2022) and the Base Period (March 2022 – February 2023). The requested annual budget for the 12 months of the Forecasted Test Period is provided in Schedule C-1. The monthly revenue and monthly O&M amounts are shown in Work Papers WPC-2d and WPC-2.1a, respectively. This data is comprised of Duke Energy Kentucky's 2023 annual budget and extended through June 2024 as described in the testimony of Mr. Carpenter.

Sponsoring Witness: Grady "Tripp" S. Carpenter

Duke Energy Segment Reporting

DE Kentucky Electric
Income Statement for Budget
Periodic

	Jan 2021 Budget Periodic	Feb 2021 Budget Periodic	Mar 2021 Budget Periodic	Apr 2021 Budget Periodic	May 2021 Budget Periodic	Jun 2021 Budget Periodic	Jul 2021 Budget Periodic	Aug 2021 Budget Periodic	Sep 2021 Budget Periodic	Oct 2021 Budget Periodic	Nov 2021 Budget Periodic	Dec 2021 Budget Periodic	Dec 2021 Budget YTD
Operating Revenue													
Regulated Electric	32,680,665	31,991,812	30,346,843	26,992,819	32,398,023	34,709,958	35,556,957	35,543,368	31,318,257	29,710,032	30,774,713	31,967,839	383,991,287
Total Operating Revenues	**32,680,665**	**31,991,812**	**30,346,843**	**26,992,819**	**32,398,023**	**34,709,958**	**35,556,957**	**35,543,368**	**31,318,257**	**29,710,032**	**30,774,713**	**31,967,839**	**383,991,287**
Operating Expenses													
Fuel used in Electric Generation and Purchased Power	8,794,280	8,510,361	8,850,787	6,449,584	9,524,705	10,066,797	9,146,370	9,408,246	8,244,736	7,519,796	7,596,939	8,110,645	102,223,246
Operations, Maintenance and Other	10,118,952	9,866,312	11,631,219	12,404,151	11,156,602	10,721,230	11,179,478	10,391,654	10,404,421	10,121,282	10,058,776	9,715,397	127,769,475
Depreciation and Amortization	6,123,797	6,121,524	6,360,088	6,401,046	6,399,020	6,412,088	6,471,304	6,471,142	6,472,379	6,487,287	6,463,000	6,463,386	76,646,062
Property and Other Taxes	1,312,944	1,312,846	1,311,804	1,306,169	1,311,131	1,313,852	1,347,044	1,315,920	1,314,057	1,315,189	1,316,574	1,345,267	15,822,797
Total Operating Expenses	**26,349,974**	**25,811,043**	**28,153,899**	**26,560,950**	**28,391,458**	**28,513,967**	**28,144,197**	**27,586,962**	**26,435,593**	**25,443,554**	**25,435,289**	**25,634,695**	**322,461,580**
Operating Income	**6,330,692**	**6,180,769**	**2,192,944**	**431,869**	**4,006,565**	**6,195,991**	**7,412,760**	**7,956,406**	**4,882,664**	**4,266,479**	**5,339,424**	**6,333,144**	**61,529,707**
Other Income and Expenses													
71XX_OTHER_INCOME - Other Income	73,937	73,937	73,937	73,937	73,937	73,937	73,937	73,937	73,937	73,937	73,937	73,937	887,244
7311_AFUDC_OTH_DF_RT - AFUDC and Other Deferred	70,122	83,259	82,407	84,420	93,270	84,608	78,200	81,633	83,415	86,182	90,126	89,877	1,007,519
7312_DEF_RETURN -Deferred Returns	67,544	67,070	66,592	66,111	65,627	65,140	64,649	64,155	63,658	63,157	62,653	62,145	778,501
7330_INTERCO_INT - Intercompany Interest Income	111,727	98,094	86,645	56,721	36,469	41,688	97,279	99,134	88,527	84,494	74,625	106,229	981,633
Other Income and Expenses	**323,330**	**322,360**	**309,581**	**281,189**	**269,303**	**265,373**	**314,065**	**318,859**	**309,537**	**307,770**	**301,341**	**332,188**	**3,654,897**
Earnings Before Interest Expense and Taxes	6,654,022	6,503,129	2,502,526	713,058	4,275,868	6,461,365	7,726,825	8,275,264	5,192,200	4,574,248	5,640,765	6,665,332	65,184,604
Interest Expense	1,611,443	1,574,041	1,596,505	1,598,363	1,558,701	1,614,858	1,612,926	1,574,410	1,684,270	1,676,161	1,636,771	1,682,805	19,421,253
Earnings From Continuing Operations Before Income Taxes	5,042,579	4,929,088	906,021	(885,305)	2,717,168	4,846,507	6,113,900	6,700,855	3,507,930	2,898,088	4,003,995	4,982,526	45,763,351
Income Tax Expense (Benefit) From Continuing Operations	974,859	943,263	(177,036)	(502,335)	391,285	1,392,216	1,240,997	1,385,142	379,834	438,233	712,515	820,097	7,999,071
Income From Continuing Operations Attributable to Duke E	**4,067,720**	**3,985,825**	**1,083,057**	**(382,970)**	**2,325,882**	**3,454,290**	**4,872,903**	**5,315,713**	**3,128,096**	**2,459,855**	**3,291,479**	**4,162,429**	**37,764,279**
Income (Loss) From Continuing Operations	**4,067,720**	**3,985,825**	**1,083,057**	**(382,970)**	**2,325,882**	**3,454,290**	**4,872,903**	**5,315,713**	**3,128,096**	**2,459,855**	**3,291,479**	**4,162,429**	**37,764,279**
Net Inc Bfr Ext and Chg in Acct. Prin.	**4,067,720**	**3,985,825**	**1,083,057**	**(382,970)**	**2,325,882**	**3,454,290**	**4,872,903**	**5,315,713**	**3,128,096**	**2,459,855**	**3,291,479**	**4,162,429**	**37,764,279**

Duke Energy Segment Reporting

DE Kentucky Electric
Income Statement for Budget
Periodic

	Jan 2021 Budget Periodic	Feb 2021 Budget Periodic	Mar 2021 Budget Periodic	Apr 2021 Budget Periodic	May 2021 Budget Periodic	Jun 2021 Budget Periodic	Jul 2021 Budget Periodic	Aug 2021 Budget Periodic	Sep 2021 Budget Periodic	Oct 2021 Budget Periodic	Nov 2021 Budget Periodic	Dec 2021 Budget Periodic	Dec 2021 Budget YTD
Consolidated Net Income	4,067,720	3,985,825	1,083,057	(382,970)	2,325,882	3,454,290	4,872,903	5,315,713	3,128,096	2,459,855	3,291,479	4,162,429	37,764,279
Less: Net (Loss) Income Attributable to Noncontrolling Intere	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Income Attributable to Company	4,067,720	3,985,825	1,083,057	(382,970)	2,325,882	3,454,290	4,872,903	5,315,713	3,128,096	2,459,855	3,291,479	4,162,429	37,764,279
Less: Preferred Dividends	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Income Attributable to Controlling Interest	4,067,720	3,985,825	1,083,057	(382,970)	2,325,882	3,454,290	4,872,903	5,315,713	3,128,096	2,459,855	3,291,479	4,162,429	37,764,279

Duke Energy Segment Reporting

DE Kentucky Electric
Income Statement for Budget
Periodic

	Jan 2022 Budget Periodic	Feb 2022 Budget Periodic	Mar 2022 Budget Periodic	Apr 2022 Budget Periodic	May 2022 Budget Periodic	Jun 2022 Budget Periodic	Jul 2022 Budget Periodic	Aug 2022 Budget Periodic	Sep 2022 Budget Periodic	Oct 2022 Budget Periodic	Nov 2022 Budget Periodic	Dec 2022 Budget Periodic	Dec 2021 Budget YTD
Operating Revenue													
Regulated Electric	29,482,484	33,750,859	33,861,023	30,237,232	30,000,523	35,583,703	40,266,334	37,729,301	33,969,618	29,452,246	30,901,915	37,232,922	402,468,161
Total Operating Revenues	**29,482,484**	**33,750,859**	**33,861,023**	**30,237,232**	**30,000,523**	**35,583,703**	**40,266,334**	**37,729,301**	**33,969,618**	**29,452,246**	**30,901,915**	**37,232,922**	**402,468,161**
Operating Expenses													
Fuel used in Electric Generation and Purchased Power	5,864,301	10,661,783	13,117,470	9,989,204	8,797,437	11,234,289	13,376,134	11,481,472	11,070,439	8,312,011	9,387,467	14,371,804	127,663,813
Operations, Maintenance and Other	10,279,474	9,882,119	10,848,386	9,908,795	9,921,490	10,158,975	10,985,060	10,651,359	10,434,485	10,836,970	10,377,108	14,163,422	128,447,644
Depreciation and Amortization	5,716,836	5,725,584	5,721,644	5,730,455	5,723,647	5,724,620	5,758,681	5,758,893	5,742,804	5,752,914	5,795,582	5,794,973	68,946,634
Property and Other Taxes	1,461,077	1,461,026	1,463,111	1,467,025	1,463,734	1,466,047	1,496,319	1,466,247	1,466,637	1,453,167	1,465,659	1,495,559	17,625,609
Total Operating Expenses	**23,321,687**	**27,730,512**	**31,150,611**	**27,095,479**	**25,906,308**	**28,583,932**	**31,616,195**	**29,357,972**	**28,714,365**	**26,355,063**	**27,025,816**	**35,825,758**	**342,683,700**
Operating Income	**6,160,797**	**6,020,347**	**2,710,412**	**3,141,753**	**4,094,215**	**6,999,772**	**8,650,139**	**8,371,329**	**5,255,252**	**3,097,183**	**3,876,099**	**1,407,163**	**59,784,461**
Other Income and Expenses													
71XX_OTHER_INCOME - Other Income	69,896	69,896	69,896	69,896	69,896	69,896	69,896	69,896	69,896	69,896	69,896	69,896	838,752
7311_AFUDC_OTH_DF_RT - AFUDC and Other Deferred Return	105,424	114,186	117,885	122,995	128,467	130,094	131,892	137,262	141,478	139,824	138,653	128,534	1,536,694
7312_DEF_RETURN -Deferred Returns	60,516	60,091	59,663	59,232	58,799	58,362	57,922	57,480	57,035	56,585	56,134	55,679	697,500
7330_INTERCO_INT - Intercompany Interest Income	86,860	91,577	87,998	55,644	50,338	60,808	53,196	61,690	62,515	60,608	60,437	83,020	814,693
Other Income and Expenses	**322,696**	**335,751**	**335,442**	**307,767**	**307,500**	**319,161**	**312,907**	**326,328**	**330,924**	**326,913**	**325,120**	**337,129**	**3,887,639**
Earnings Before Interest Expense and Taxes	6,483,494	6,356,097	3,045,854	3,449,520	4,401,715	7,318,933	8,963,046	8,697,658	5,586,176	3,424,097	4,201,219	1,744,293	63,672,101
Interest Expense	1,612,454	1,598,249	1,651,385	1,623,005	1,585,529	1,648,624	1,633,323	1,595,671	1,661,196	1,631,007	1,596,561	1,665,292	19,502,296
Earnings From Continuing Operations Before Income Taxes	4,871,040	4,757,848	1,394,469	1,826,515	2,816,187	5,670,309	7,329,723	7,101,987	3,924,980	1,793,090	2,604,658	79,000	44,169,804
Income Tax Expense (Benefit) From Continuing Operations	818,088	792,008	(642,432)	62,582	306,435	1,385,506	1,435,746	1,370,320	490,117	46,644	251,796	(48,143)	6,268,665
Income From Continuing Operations Attributable to Duke Energy Corp	**4,052,952**	**3,965,840**	**2,036,901**	**1,763,933**	**2,509,751**	**4,284,803**	**5,893,977**	**5,731,667**	**3,434,864**	**1,746,446**	**2,352,862**	**127,144**	**37,901,139**
Income (Loss) From Continuing Operations	**4,052,952**	**3,965,840**	**2,036,901**	**1,763,933**	**2,509,751**	**4,284,803**	**5,893,977**	**5,731,667**	**3,434,864**	**1,746,446**	**2,352,862**	**127,144**	**37,901,139**
Net Inc Bfr Ext and Chg in Acct. Prin.	**4,052,952**	**3,965,840**	**2,036,901**	**1,763,933**	**2,509,751**	**4,284,803**	**5,893,977**	**5,731,667**	**3,434,864**	**1,746,446**	**2,352,862**	**127,144**	**37,901,139**
Consolidated Net Income	4,052,952	3,965,840	2,036,901	1,763,933	2,509,751	4,284,803	5,893,977	5,731,667	3,434,864	1,746,446	2,352,862	127,144	37,901,139
Less: Net (Loss) Income Attributable to Noncontrolling Interests	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Income Attributable to Company	4,052,952	3,965,840	2,036,901	1,763,933	2,509,751	4,284,803	5,893,977	5,731,667	3,434,864	1,746,446	2,352,862	127,144	37,901,139
Less: Preferred Dividends	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Income Attributable to Controlling Interest	4,052,952	3,965,840	2,036,901	1,763,933	2,509,751	4,284,803	5,893,977	5,731,667	3,434,864	1,746,446	2,352,862	127,144	37,901,139

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Duke Energy Segment Reporting

DE Kentucky Electric
Income Statement for Budget
Periodic

	Jan 2023 Budget Periodic	Feb 2023 Budget Periodic	Mar 2023 Budget Periodic	Apr 2023 Budget Periodic	May 2023 Budget Periodic	Jun 2023 Budget Periodic	Jul 2023 Budget Periodic	Aug 2023 Budget Periodic	Sep 2023 Budget Periodic	Oct 2023 Budget Periodic	Nov 2023 Budget Periodic	Dec 2023 Budget Periodic	Dec 2023 Budget YTD
Operating Revenue													
Regulated Electric	32,866,604	33,353,157	31,489,271	28,402,990	29,993,690	36,571,078	40,137,160	39,602,567	34,127,239	30,810,991	32,350,578	32,841,213	402,546,537
Total Operating Revenues	**32,866,604**	**33,353,157**	**31,489,271**	**28,402,990**	**29,993,690**	**36,571,078**	**40,137,160**	**39,602,567**	**34,127,239**	**30,810,991**	**32,350,578**	**32,841,213**	**402,546,537**
Operating Expenses													
Fuel used in Electric Generation and Purchased Power	9,381,250	9,897,815	10,554,046	8,330,364	8,529,277	12,421,103	13,548,167	13,277,838	11,205,705	9,563,942	10,538,018	10,745,479	127,993,003
Operations, Maintenance and Other	13,907,305	9,906,878	11,524,363	10,370,431	9,663,620	9,181,709	9,960,318	10,592,036	9,886,295	9,760,078	10,490,232	11,126,674	126,369,938
Depreciation and Amortization	5,998,186	5,966,327	5,966,051	5,993,825	5,909,840	5,911,177	5,975,460	5,931,955	5,971,240	6,009,721	6,009,060	6,015,463	71,658,304
Property and Other Taxes	1,741,293	1,741,293	1,741,293	1,741,293	1,741,293	1,741,293	1,741,293	1,741,293	1,741,293	1,741,293	1,741,293	1,741,293	20,895,519
Total Operating Expenses	**31,028,034**	**27,512,314**	**29,785,754**	**26,435,913**	**25,844,030**	**29,255,281**	**31,225,238**	**31,543,122**	**28,804,532**	**27,075,034**	**28,778,604**	**29,628,909**	**346,916,765**
Operating Income	**1,838,571**	**5,840,843**	**1,703,517**	**1,967,077**	**4,149,659**	**7,315,797**	**8,911,922**	**8,059,446**	**5,322,706**	**3,735,957**	**3,571,975**	**3,212,303**	**55,629,772**
Other Income and Expenses													
71XX_OTHER_INCOME - Other Income	79,091	79,091	79,091	79,091	79,091	79,091	79,091	79,091	79,091	79,091	79,091	79,091	949,092
7311_AFUDC_OTH_DF_RT - AFUDC and Other Deferred Return	111,494	115,839	115,880	119,571	126,966	116,334	107,166	108,095	107,322	111,759	117,246	104,804	1,362,477
7312_DEF_RETURN -Deferred Returns													0
7330_INTERCO_INT - Intercompany Interest Income	101,640	111,429	108,897	74,323	66,704	74,642	63,280	70,120	90,285	100,356	90,836	109,938	1,062,449
Other Income and Expenses	**292,225**	**306,359**	**303,868**	**272,985**	**272,762**	**270,067**	**249,537**	**257,306**	**276,697**	**291,206**	**287,173**	**293,833**	**3,374,019**
Earnings Before Interest Expense and Taxes	2,130,796	6,147,201	2,007,385	2,240,061	4,422,421	7,585,864	9,161,459	8,316,752	5,599,404	4,027,163	3,859,147	3,506,137	59,003,790
Interest Expense	1,700,120	1,675,889	1,717,552	1,700,305	1,661,481	1,728,616	1,704,878	1,668,461	1,955,542	1,958,757	1,890,422	1,958,913	21,320,936
Earnings From Continuing Operations Before Income Taxes	430,676	4,471,313	289,833	539,757	2,760,940	5,857,248	7,456,582	6,648,291	3,643,862	2,068,407	1,968,726	1,547,223	37,682,855
Income Tax Expense (Benefit) From Continuing Operations	(171,345)	831,983	(207,630)	(146,508)	403,746	1,176,036	1,575,815	1,374,550	627,749	234,894	208,654	106,865	6,014,808
Income From Continuing Operations Attributable to Duke Energy Corp	**602,021**	**3,639,329**	**497,463**	**686,265**	**2,357,194**	**4,681,212**	**5,880,767**	**5,273,741**	**3,016,113**	**1,833,513**	**1,760,072**	**1,440,358**	**31,668,047**
Income (Loss) From Continuing Operations	**602,021**	**3,639,329**	**497,463**	**686,265**	**2,357,194**	**4,681,212**	**5,880,767**	**5,273,741**	**3,016,113**	**1,833,513**	**1,760,072**	**1,440,358**	**31,668,047**
Net Inc Bfr Ext and Chg in Acct. Prin.	**602,021**	**3,639,329**	**497,463**	**686,265**	**2,357,194**	**4,681,212**	**5,880,767**	**5,273,741**	**3,016,113**	**1,833,513**	**1,760,072**	**1,440,358**	**31,668,047**
Consolidated Net Income	602,021	3,639,329	497,463	686,265	2,357,194	4,681,212	5,880,767	5,273,741	3,016,113	1,833,513	1,760,072	1,440,358	31,668,047
Less: Net (Loss) Income Attributable to Noncontrolling Interests	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Income Attributable to Company	602,021	3,639,329	497,463	686,265	2,357,194	4,681,212	5,880,767	5,273,741	3,016,113	1,833,513	1,760,072	1,440,358	31,668,047
Less: Preferred Dividends	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Income Attributable to Controlling Interest	602,021	3,639,329	497,463	686,265	2,357,194	4,681,212	5,880,767	5,273,741	3,016,113	1,833,513	1,760,072	1,440,358	31,668,047

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DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(e)

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807 KAR 5:001, SECTION 16(7)(e)

Description of Filing Requirement:

A statement of attestation signed by the utility's chief officer in charge of Kentucky operations which shall provide:

(1) that the forecast is reasonable, reliable, made in good faith and that all basic assumptions used in the forecast have been identified and justified;

(2) that the forecast contains the same assumptions and methodologies as used in the forecast prepared for use by management, or an identification and explanation for any differences that exist; and

(3) that productivity and efficiency gains are included in the forecast.

Response:

See attached.

Sponsoring Witness: Amy B. Spiller

AFFIDAVIT OF AMY B. SPILLER

STATE OF OHIO)
)
COUNTY OF HAMILTON)

Now comes Amy B. Spiller, President of Duke Energy Kentucky, Inc., and as required by 807 KAR 5:001, Section 16(7)(e), hereby attests as follows:

1. The forecast used in this rate application is reasonable, reliable, made in good faith, and that all basic assumptions used in the forecast have been identified and justified;
2. The forecast contains the same assumptions and methodologies as used in the forecast prepared for use by management, or an identification and explanation for any differences that exist, if applicable; and
3. Productivity and efficiency gains are included in the forecast.

Further affiant sayeth naught.

Amy B. Spiller, Affiant

Sworn and subscribed before me by Amy B. Spiller on this 30th day of November 2022.

Notary Public

My Commission Expires: July 8, 2027

EMILIE SUNDERMAN
Notary Public
State of Ohio
My Comm. Expires
July 8, 2027

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(f)(1) through (4)

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807 KAR 5:001, SECTION 16(7)(f)(1) through (4)

Description of Filing Requirement:

For each major construction project which constitutes five (5) percent or more of the annual construction budget within the three (3) year forecast the following information shall be filed:

(1) The date the project was started or estimated starting date;

(2) The estimated completion date;

(3) The total estimated cost of construction by year exclusive and inclusive of allowance for funds used during construction ("AFUDC") or interest during construction credit; and,

(4) The most recent available total costs incurred exclusive and inclusive of AFUDC or interest during construction credit.

Response:

See attached.

Sponsoring Witness:

Grady “Tripp” S. Carpenter
Dominic “Nick” J. Melillo
William C. Luke

Duke Energy Kentucky, Inc.
Case No. 2022-00372
Major Construction Projects
Constituting 5% or More of Annual Budget

Line No.	Project ID/Description	Actual or Projected Start Date	Projected Completion Date	Estimated Costs Including AFUDC 2022	Estimated Costs Including AFUDC 2023	Estimated Costs Including AFUDC 2024	Estimated Costs Excluding AFUDC 2022	Estimated Costs Excluding AFUDC 2023	Estimated Costs Excluding AFUDC 2024	Actual Costs To Date incl AFUDC	Actual Costs To Date excl AFUDC
1	DCAPINC - Taylor Mill Sub - DKY2135 -Tier 1	1/1/2023	12/31/2024	0	1,232,183	12,142,532		1,216,791	11,960,063	0	0
2	M190309 - Hebron-Oakbrook-Install 69 kV Circuit	3/1/2022	12/31/2024	195,652	6,480,644	13,078,184	193,208	6,394,800	12,748,011	0	0
3	WD301205 WGS CT3 Overhaul No 3	1/1/2024	4/30/2024	0	0	16,868,503	0	0	16,657,782	0	0

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(g)

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807 KAR 5:001, SECTION 16(7)(g)

Description of Filing Requirement:

For all construction projects which constitute less than five (5) percent of the annual construction budget within the three (3) year forecast, the utility shall file an aggregate of the information requested in paragraph (f) 3 and 4 of this subsection.

Response:

See attached.

Sponsoring Witness:

Grady "Tripp" S. Carpenter
Dominic "Nick" J. Melillo
William C. Luke

Duke Energy Kentucky, Inc.
Case No. 2022-00372
Major Construction Projects
Constituting Less than 5% of Annual Budget

Line No.	Project ID/Description	Actual or Projected Start Date	Projected Completion Date	Estimated Costs Including AFUDC 2022	Estimated Costs Including AFUDC 2023	Estimated Costs Including AFUDC 2024	Estimated Costs Excluding AFUDC 2022	Estimated Costs Excluding AFUDC 2023	Estimated Costs Excluding AFUDC 2024	Actual Costs To Date incl AFUDC	Actual Costs To Date excl AFUDC
1	Sum of all projects not included on 7(f)	Various	Various	84,574,922	112,464,584	90,300,358	83,009,092	111,493,619	89,844,637	77,984,860	76,510,010

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(h)

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807 KAR 5:001, SECTION 16(7)(h)

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

(1) Operating income statement (exclusive of dividends per share or earnings per share);

(2) Balance sheet;

(3) Statement of cash flows;

(4) Revenue requirements necessary to support the forecasted rate of return;

(5) Load forecast including energy and demand (electric);

(6) Access line forecast (telephone);

(7) Mix of generation (electric);

(8) Mix of gas supply (gas);

(9) Employee level;

(10) Labor cost changes;

(11) Capital structure requirements;

(12) Rate base;

(13) Gallons of water projected to be sold (water);

(14) Customer forecast (gas, water);

(15) MCF sales forecasts (gas);

(16) Toll and access forecast of number of calls and number of minutes (telephone); and

(17) A detailed explanation of any other information provided, if applicable.

Response:

Items 6, 13, 16, and 17 are not applicable. For all other items, see attached.

Sponsoring Witnesses:

Grady "Tripp" S. Carpenter – Items 1, 2, 3, 4, 8, 9, 10, 11, 12
Max W. McClellan – Item 5, 14, 15
John D. Swez – Item 7

FR 16(7)(h)(1)

Duke Energy Kentucky, Inc.
Case No. 2022-00372
Projected Income Statement 2022-2024

Line No.	Description	2022	2023	2024
1	Operating Revenue			
2	Electric Revenue	$ 401,225,161	$ 418,696,537	$ 432,466,650
3	Gas Revenue	144,773,990	135,829,851	137,830,637
4	Other Revenue	1,478,000	850,000	850,000
5	Total Operating Revenue	$ 547,477,152	$ 555,376,387	$ 571,147,288
6	Operating Expenses			
7	Fuel & Purchased Power	127,663,813	127,993,003	131,371,519
8	Gas Purchased	61,344,660	51,527,516	48,332,383
9	Operation & Maintenance	154,009,135	149,292,695	151,236,471
10	Depreciation & Amortization	90,456,111	93,284,045	88,548,330
11	Taxes Other Than Income	22,224,888	27,178,777	29,342,585
12	Operating Expenses before Income Tax	$ 455,698,607	$ 449,276,037	$ 448,831,287
13	Pre-Tax Operating Income	$ 91,778,545	$ 106,100,351	$ 122,316,001
14	Other Income	4,283,965	4,591,620	5,155,608
15	Interest Expense	27,489,270	29,508,453	33,111,451
16	State Income Taxes	3,285,050	3,897,796	4,539,862
17	Federal Income Taxes	8,309,203	11,949,918	14,574,710
18	Total Income Taxes	$ 11,594,253	$ 15,847,714	$ 19,114,572
19	Income Available for Common Dividends	$ 56,978,987	$ 65,335,804	$ 75,245,585
20	Average Common Equity	$ 1,033,399,742	$ 1,104,557,138	$ 1,164,847,832
21	Earned Return	5.51%	5.92%	6.46%

FR 16(7)(h)(2)

Duke Energy Kentucky, Inc.
Case No. 2022-00372
Projected Balance Sheet 2022-2024

Line No.	Description	2022	2023	2024
1	**Assets**			
2	Utility plant in service	$ 3,118,609,104	$ 3,288,063,566	$ 3,420,204,865
3	Construction work in progress	79,918,027	78,859,891	115,824,820
4	Total Utility Plant	$ 3,198,527,131	$ 3,366,923,456	$ 3,536,029,686
5	Non-regulated property, plant, and equipment	2,206	2,206	2,206
6	Accumulated depreciation	1,093,090,098	1,125,131,132	1,160,135,788
7	Net Property, Plant, and Equipment	$ 2,105,439,239	$ 2,241,794,531	$ 2,375,896,104
8	Current Assets	138,648,437	140,459,162	141,949,905
9	Other Assets	303,807,587	287,295,810	274,824,567
10	Total Assets	$ 2,547,895,263	$ 2,669,549,503	$ 2,792,670,576
	Liabilities			
11	Total Current Liabilities	231,128,968	148,506,067	249,368,255
12	Long-term debt	704,473,994	834,759,521	789,977,793
13	Accumulated deferred income taxes	277,826,996	286,450,141	298,832,929
14	Excess deferred income taxes	105,793,229	102,020,643	98,248,057
15	Unamortized investment tax credits	4,860,977	4,860,977	4,860,977
16	Other	151,921,862	155,727,114	158,911,940
17	Total Non-Current Liabilities	$ 1,244,877,059	$ 1,383,818,397	$ 1,350,831,696
18	Total Common Stock Equity	1,071,889,236	1,137,225,039	1,192,470,625
19	Total Liabilities	$ 2,547,895,263	$ 2,669,549,503	$ 2,792,670,576

FR 16(7)(h)(3)

Duke Energy Kentucky, Inc.
Case No. 2022-00372
Projected Cash Flow Statement 2022-2024

Line No.	Description	2022	2023	2024
1	Net Income	$ 56,978,987	$ 65,335,804	$ 75,245,585
2	Other Operating Activities	115,000,030	103,445,522	106,372,062
3	Cash from Operating Activities	$ 171,979,017	$ 168,781,326	$ 181,617,647
4	Financing Activities			
5	Change in contributed capital	$ 20,000,000	$ -	$ (20,000,000)
6	Change in short-term debt	(89,708,448)	(12,887,552)	0
7	Issuance of long-term debt	50,000,000	130,000,000	50,000,000
8	Change in non-current capital leases	-	-	-
9	Redemption of long-term debt	-	(75,000,000)	-
10	Dividends on common stock	-	-	-
11	Cash from Financing Actitivies	$ (19,708,448)	$ 42,112,448	$ 30,000,000
12	Investing Activities			
13	Construction Expenditures (net of AFUDC)	$ (153,942,769)	$ (205,103,432)	$ (205,878,882)
14	Acquisitions and other investments	(2,810,347)	(3,508,000)	(3,894,240)
15	Cash from Investing Actitivies	$ (156,753,116)	$ (208,611,432)	$ (209,773,122)
16	Net Increase/(Decrease) in Cash	$ (4,482,547)	$ 2,282,342	$ 1,844,526

FR 16(7)(h)(4)

Duke Energy Kentucky, Inc.
Case No. 2022-00372
Revenue Requirements 2022-2024

Line No.	Description	2022	2023	2024
1	Rate Base	$ 1,178,814,462	$ 1,244,374,640	$ 1,316,668,028
2	Operating Income	$ 55,342,570	$ 52,480,536	$ 61,803,566
3	Earned Rate of Return (Line 2 / Line 1)	4.700%	4.200%	4.700%
4	Rate of Return	7.477%	7.526%	7.526%
5	Required Operating Income (Line 1 x Line 4)	$ 88,139,957	$ 93,651,635	$ 99,092,436
6	Operating Income Deficiency (Line 5 - Line 2)	$ 32,797,387	$ 41,171,099	$ 37,288,870
7	Gross Revenue Conversion Factor	1.3342383	1.3342383	1.3342383
8	Revenue Deficiency (Line 6 x Line 7)	$ 43,759,529	$ 54,932,057	$ 49,752,238

FR 16(7)(h)(5)

Duke Energy Kentucky, Inc.
Case No. 2022-00372
Load Forecast 2022-2024

Line No.	Description	2022	2023	2024
1	KW Demand - Coincident Peak			
2				
3	January	733,350	747,481	747,031
4	February	673,458	687,285	687,388
5	March	633,797	647,044	649,461
6	April	559,390	572,105	574,535
7	May	594,025	607,231	608,542
8	June	709,603	723,095	725,667
9	July	822,036	835,963	840,092
10	August	793,192	806,961	809,922
11	September	690,853	704,306	706,784
12	October	502,668	515,223	515,478
13	November	595,450	607,426	608,355
14	December	689,952	702,644	704,101
15				
16	KWH Sales			
17				
18	January	359,852,180	370,202,250	362,876,330
19	February	333,374,170	343,322,270	346,443,260
20	March	309,565,780	319,176,380	322,786,940
21	April	281,747,980	287,416,900	287,813,320
22	May	299,581,790	305,239,200	305,561,450
23	June	354,377,180	360,228,380	360,733,360
24	July	405,589,590	411,490,630	414,056,520
25	August	394,081,590	400,107,390	402,641,390
26	September	344,541,100	350,748,560	353,266,200
27	October	303,610,430	307,098,490	308,736,700
28	November	304,794,120	308,459,870	309,997,030
29	December	342,600,170	345,913,450	347,752,960

FR 16(7)(h)(7)

Duke Energy Kentucky, Inc.
Case No. 2022-00372
Mix of Generation 2022-2024

Line No.	Description	2022	2023	2024
1	Coal	3,351,614	1,512,280	1,114,920
2	Natural Gas	10,851	10,918	13,785
3	Oil	-	-	-
4	Total Generation (MWH)	3,362,466	1,523,198	1,128,705

FR 16(7)(h)(8)

Duke Energy Kentucky, Inc.
Case No. 2022-00372
Mix of Gas Supply 2022-2024

Line No.	Description	2022	2023	2024
1	Columbia Gas Trans - No Notice	1,067,007	1,067,007	1,067,007
2	Undetermined	8,951,747	8,943,404	8,968,090
3	Propane - Air	45,000	45,000	45,000
4	Total Supply - MCF	10,063,753	10,055,411	10,080,096
5	Columbia Gas Trans - No Notice	$ 4,100,284	$ 4,350,663	$ 3,832,137
6	Undetermined	48,658,573	37,286,111	34,021,756
7	Propane - Air	545,387	545,387	545,387
8	Demand Costs	8,623,929	10,110,395	10,230,609
9	Total Cost	$ 61,928,173	$ 52,292,556	$ 48,629,889

FR 16(7)(h)(9)

Duke Energy Kentucky, Inc.
Case No. 2022-00372
Number of Employees 2022-2024

Line No.	Description	2022	2023	2024
1	Number of employees	158	158	158

This count includes only direct employees of Duke Energy Kentucky, Inc.

FR 16(7)(h)(10)

Duke Energy Kentucky, Inc.
Case No. 2022-00372
Labor Cost Changes 2022-2024

Line No.	Description	2022	2023	2024
1	Total Labor Costs:			
2				
3	Gas O&M Expense	$ 8,985,172	$ 8,669,226	$ 8,755,918
4	Electric O&M Expense	27,721,238	27,868,881	28,147,570
5	Total O&M	$ 36,706,410	$ 36,538,107	$ 36,903,488
6				
7	Gas Capital	$ 6,466,562	$ 6,036,839	$ 6,097,207
8	Electric Capital	12,850,557	11,656,375	11,772,939
9	Non-jurisdictional Capital	-	-	-
10	Total Capital	$ 19,317,119	$ 17,693,213	$ 17,870,146
11				
12	Total	$ 56,023,530	$ 54,231,320	$ 54,773,634

Includes incentives (direct & allocated).

FR 16(7)(h)(11)

Duke Energy Kentucky, Inc.
Case No. 2022-00372
Capital Structure Requirements 2022-2024

Line No.	Description	2022		2023		2024	
1	Common Equity	$ 1,071,889,236	57.497%	$ 1,137,225,039	57.669%	$ 1,192,470,625	57.399%
2	Long-term Debt	704,473,994	37.788%	834,759,521	42.330%	789,977,793	38.026%
3	Short-term Debt	87,892,163	4.715%	22,135	0.001%	95,039,390	4.575%
4	Total Capital	$ 1,864,255,392	100.00%	$ 1,972,006,695	100.00%	$ 2,077,487,807	100.00%

FR 16(7)(h)(12)

Duke Energy Kentucky, Inc.
Case No. 2022-00372
Rate Base 2022-2024

Line No.	Description	2022	2023	2024
1	Adjusted Jurisdictional Plant in Service	$ 2,255,409,616	$ 2,350,548,998	$ 2,432,168,799
2	Accumulated Depreciation and Amortization	(899,218,782)	(918,277,870)	(939,397,400)
3	Net Plant in Service (Line 1 + Line 2)	$ 1,356,190,833	$ 1,432,271,128	$ 1,492,771,399
4	Construction Work in Progress	45,544,920	37,965,153	55,982,323
5	Cash Working Capital Allowance	16,220,280	15,944,495	16,186,690
6	Other Working Capital Allowances	44,381,595	44,381,595	44,381,595
7	Other Items:			
8	Customers' Advances for Construction	0	0	0
9	Investment Tax Credits	(4,536,501)	(4,536,501)	(4,536,501)
10	Deferred Income Taxes	(212,321,839)	(218,128,554)	(227,736,952)
11	Excess Deferred Income Taxes	(66,664,826)	(63,522,676)	(60,380,526)
12	Other Rate Base Adjustments	0	0	0
13	Jurisdictional Rate Base (Line 3 through Line 11)	$ 1,178,814,462	$ 1,244,374,640	$ 1,316,668,028

FR 16(7)(h)(14)

Duke Energy Kentucky, Inc.
Case No. 2022-00372
Customer Forecast 2022-2024

Line No.	Description	2022	2023	2024
1	Residential	131,957	133,079	134,170
2	Commercial	13,904	13,941	13,975
3	Industrial	352	348	345
4	Other	1,405	1,414	1,424
5	Total Electric Retail	147,618	148,781	149,913
6	Residential	95,647	96,368	97,121
7	Commercial	7,196	7,250	7,307
8	Industrial	207	209	211
9	Other	317	319	322
10	Total Full Requirements	103,367	104,146	104,960
11				
12	Transportation			
13	Commercial	42	43	43
14	Industrial	37	37	37
15	Other	35	35	36
16	Total Transportation	115	115	116
17				
18	Total Gas Retail (Line 10 + Line 16)	103,481	104,262	105,076

FR 16(7)(h)(15)

Duke Energy Kentucky, Inc.
Case No. 2022-00372
MCF Sales Forecast 2022-2024

Line No.	Description	2022	2023	2024
1	Residential	6,193,134	6,212,339	6,236,623
2	Commercial	3,093,033	3,093,701	3,152,719
3	Industrial	280,033	263,033	264,828
4	Other	396,607	398,430	401,289
5	Interdepartmental	4,148	4,152	4,166
6	Total Retail	9,966,955	9,971,654	10,059,626
7	Transportation			
8	Commercial	865,819	1,076,220	1,091,135
9	Industrial	1,706,550	1,596,372	1,611,043
10	Other	1,707,390	1,714,198	1,722,400
11	Total Transportation	4,279,759	4,386,790	4,424,577
12	Total MCF Sales	14,246,714	14,358,445	14,484,203

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(i)

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807 KAR 5:001, SECTION 16(7)(i)

Description of Filing Requirement:

The most recent Federal Energy Regulatory Commission or Federal Communication Commission audit reports.

Response:

See attached.

Witness Responsible:

Danielle L. Weatherston

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. PA14-2-000
April 1, 2016

Duke Energy Corporation
Attention: Mr. Brian D. Savoy
Senior Vice President, Chief Accounting
Officer and Controller
550 South Tryon St.
Charlotte, NC 28202

Dear Mr. Savoy:

1. The Division of Audits and Accounting (DAA) within the Office of Enforcement (OE) of the Federal Energy Regulatory Commission (Commission) has completed an audit of Duke Energy Corporation (Duke Energy) and its public utility subsidiaries. The audit covered the period from January 1, 2011 through January 31, 2016.

2. The audit evaluated Duke Energy's compliance with conditions and requirements established in Commission orders authorizing the merger of Duke Energy and Progress Energy, Inc. The audit also evaluated each Duke Energy public utility subsidiary's compliance with: (1) tariff requirements governing its transmission formula rate; (2) accounting regulations in 18 C.F.R. Part 101, Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act; and (3) financial reporting regulations in 18 C.F.R. Part 141, Statements and Reports. The enclosed audit report contains eight findings and 37 recommendations that require Duke Energy to take corrective action.

3. On March 30, 2016, you notified DAA that Duke Energy does not contest the audit report or any of its recommendations. A copy of your verbatim response is included as an appendix to this report. I hereby approve the audit report.

4. Duke Energy should submit its implementation plan to comply with the recommendations within 30 days of this letter order. Duke Energy should make quarterly submissions to DAA describing the progress made to comply with the recommendations, including the completion date for each corrective action. As directed by the audit report, these submissions should be made no later than 30 days after the end of each calendar quarter, beginning with the first quarter after this audit report is issued, and continuing until all the corrective actions are completed.

5. The Commission delegated authority to act on this matter to the Director of OE under 18 C.F.R. § 375.311 (2015). This letter order constitutes final agency action. Duke Energy may file a request for rehearing with the Commission within 30 days of the date of this order under 18 C.F.R. § 385.713 (2015).

6. This letter order is without prejudice to the Commission's right to require hereafter any adjustments it may consider proper from additional information that may come to its attention. In addition, any instance of noncompliance not addressed herein or that may occur in the future may also be subject to investigation and appropriate remedies.

7. I appreciate the courtesies extended to the auditors. If you have any questions, please contact Mr. Bryan K. Craig, Director and Chief Accountant, Division of Audits and Accounting at (202) 502-8741.

Sincerely,

Larry R. Parkinson
Director
Office of Enforcement

Enclosure

Federal Energy Regulatory Commission
Office of Enforcement
Division of Audits and Accounting

AUDIT REPORT

Audit of Duke Energy Corporation and its Public Utility Subsidiaries' Compliance with:

- Conditions in Commission Merger Authorization Orders;
- Transmission Formula Rate Tariff Requirements; and
- Accounting and Financial Reporting Regulations.

Docket No. PA14-2-000
March 29, 2016

Table of Contents

I. Executive Summary

A. Overview

The Division of Audits and Accounting (DAA) in the Office of Enforcement has completed an audit of Duke Energy Corporation (Duke Energy) and its public utility subsidiaries'[1] (collectively, Duke Companies) compliance with conditions and requirements established in Commission orders authorizing the merger of Duke Energy and Progress Energy, Inc. (Progress Energy).[2] The audit also evaluated each Duke Energy public utility subsidiary's compliance with: (1) tariff requirements governing its transmission formula rate; (2) accounting regulations in 18 C.F.R. Part 101, Uniform System of Accounts (USofA) Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act; and (3) financial reporting regulations in 18 C.F.R. Part 141, Statements and Reports. The audit covered the period January 1, 2011 through January 31, 2016.

B. Duke Energy Corporation

Duke Energy is a public utility holding company headquartered in Charlotte, NC. It is engaged in energy production, trade, transmission, and distribution through its six public utility subsidiaries that operate in the Southeast and Midwest regions of the United States. In 2014, Duke Energy was the largest electric utility in the nation. The company had 7.3 million retail electric and 500,000 natural gas customers, 32,400 miles of transmission lines, 57,500 MW of generating capacity, and total operating revenue of $23.9 billion. Its service area covered about 95,000 square miles and had an estimated population of 23 million. Regulated operations accounted for over 90 percent of the company's total revenue, and commercial power generation and international operations provided most of the remainder.

[1] The Duke Energy public utility subsidiaries are: Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP), Duke Energy Florida, LLC (DEF), Duke Energy Indiana, LLC (DEI), Duke Energy Ohio, Inc. (DEO), and Duke Energy Kentucky, Inc. (DEK).

[2] *Duke Energy Corp. and Progress Energy, Inc.*, 136 FERC ¶ 61,245 (2011) (Merger Order), *order on compliance*, 137 FERC ¶ 61,210 (2011), *order on compliance*, 139 FERC ¶ 61,194 (2012) (June 8 Compliance Order), *order on compliance*, 149 FERC ¶ 61,078 (2014) (October 29 Compliance Order).

C. Summary of Compliance Findings

Audit staff identified eight findings of noncompliance. Below is a summary of audit staff's compliance findings. Details are in section IV of this report.

- *Accounting for Merger Transaction Costs* – Duke Companies did not file merger transaction accounting entries with the Commission as required by the Merger Order, and the companies recorded merger transaction costs in operating accounts, contrary to the Commission's long-standing policy that such costs be recorded in nonoperating accounts. By not filing the accounting entries, Duke Companies prevented Commission review of the merger accounting and correction of any entries that were not in accordance with Commission accounting requirements.

- *Merger Transaction Internal Labor Costs* – Duke Companies improperly included approximately $31.4 million of merger transaction internal labor costs in wholesale power and transmission formula rate service cost determinations without first submitting a section 205 filing demonstrating that the costs were offset by quantified savings produced by the merger. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $17.5 million.

- *Merger Transaction Outside Services and Related Costs* – Duke Companies incorrectly included $1.5 million of merger transaction outside services and related costs in wholesale power and transmission formula rate service cost determinations without first submitting a section 205 filing demonstrating the costs were offset by quantified savings produced by the merger. In addition, the companies recorded the merger transaction costs in operating accounts, contrary to the Commission's long-standing policy that such costs be recorded in nonoperating accounts. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $745,000.

- *Use of the Consolidation Method of Accounting* – DEC and DEP accounted for investments in subsidiaries on a consolidated basis in their FERC Form No. 1, Annual Reports (Form No. 1), contrary to the Commission's long-standing accounting policy.

- *Accounting for Sales of Accounts Receivable* – DEC, DEP, and DEF misclassified an estimated $94.7 million of nonoperating expenses and receivables arising from transactions with their subsidiaries during the audit period. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $61 million.

- *Accounting for Lobbying Expenses:* Duke Companies recorded approximately $2.4 million of lobbying expenses in above-the-line operating accounts from 2011 through 2013. As a consequence, Duke Companies improperly included these costs in wholesale power and transmission formula rate service cost determinations.

- *Allocation of Lobbyist Labor Costs:* Duke Companies accounted for the labor costs of internal lobbyists and their support staff in operating accounts that lacked support for inclusion in the accounts. Improper accounting for the costs can lead to inappropriate recovery of the costs through rates charged and billed to customers.

- *Nonutility Expenses in Operating Accounts:* Duke Companies recorded approximately $490,000 of nonutility expenses in operating accounts in 2014. As a result, inappropriate costs were included in wholesale power and transmission formula rate service cost determinations and charged to customers.

D. Summary of Recommendations

Audit staff's recommendations to remedy the findings are summarized below with details in section IV of this report. Audit staff recommends that Duke Companies:

Accounting for Merger Transaction Costs

1. Revise accounting policies and procedures to appropriately account for merger transactions consistent with Commission accounting requirements.

2. Develop written policies and procedures to timely identify proposed accounting transactions that would trigger a notification to the Commission.

3. Develop written policies and procedures to submit accounting questions of doubtful interpretation to the Commission.

4. Provide training to employees on compliance with the merger cost accounting conditions and the revised policies, procedures, and controls for complying with the conditions. Also, develop a training program that supports the provision of periodic training in this area.

Merger Transaction Internal Labor Costs

5. Revise all policies and procedures for tracking, accounting, and excluding merger transaction costs from wholesale power and transmission formula rates, including amounts previously charged to utility plant, accumulated deferred income taxes, construction work in progress with the associated capitalized cost of funds used during construction (AFUDC), and maintenance and operating expense accounts, and future charges to such accounts for any transaction to which a FERC hold harmless obligation applies. The revised procedures should hold customers harmless from all merger transaction costs consistent with requirements of the Merger Order. Among other things, the revised policies and procedures should include an annual review of each subsidiary's merger transaction cost adjustments as well as periodic evaluations within the year, as needed and appropriate.

6. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the inclusion of merger transaction internal labor and related costs in wholesale power and transmission formula rates during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

7. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

8. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Merger Transaction Outside Services and Related Costs

9. Revise accounting policies and procedures to appropriately account for merger transaction costs consistent with Commission accounting requirements.

10. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the inclusion of merger transaction outside services and related costs in wholesale power and transmission formula rate charges during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

11. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

12. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Use of the Consolidation Method of Accounting

13. Review and, as needed, revise accounting policies, practices, and procedures to ensure that investments in subsidiaries are accounted for consistent with the Commission's equity method accounting requirements.

14. Evaluate the accounting applied to Duke Companies' existing subsidiaries and notify DAA of any areas of noncompliance with Commission accounting requirements.

15. Revise documented policies, procedures and processes to ensure timely notice is provided to relevant regulators regarding instances of noncompliance with regulations, rules, and orders.

16. Provide training to staff on procedures, practices, and available tools to transparently or anonymously report instances of noncompliance to senior management, the Board of Directors, and relevant regulators.

Accounting for Sales of Accounts Receivable

17. Revise procedures to ensure that all costs and account balances associated with the sale of accounts receivable are accounted for in accordance with Commission accounting regulations. Among other things, the corrected accounting should ensure that all losses associated with receivable sales are recorded in Account 426.5.

18. Provide the revised procedures to DAA for review within 60 days of receiving the final audit report.

19. Recalculate charges to wholesale power and transmission customers of DEC, DEP, and DEF and submit the recalculations in a refund analysis to DAA for review within 60 days of receiving the final audit report. The refund analysis should explain and detail the: (1) return of collection service billings charged in 2014; (2) return of losses on the sales included in rates; (3) determinative components of the refund; (4) refund method; (5) period(s) refunds will be

made; and (6) interest calculated in accordance with section 35.19 of Commission regulations.

20. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

21. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Accounting for Lobbying Expenses

22. Establish and implement written procedures governing the methods used to account for, track, report, and review lobbying costs incurred.

23. Provide training on Commission accounting requirements and the impact of accounting on cost-of-service rate determinations to employees involved in lobbying and lobbying-related work, and those with oversight responsibility for lobbying cost allocations. Also, develop a training program that supports the provision of periodic training in this area.

24. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the improper inclusion of lobbying cost in operating accounts during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

25. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

26. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Allocation of Lobbyist Labor Costs

27. Revise written policies and procedures to create a process to document and verify appropriate allocation of lobbying and lobbying-related costs, and maintain auditable support for the cost included in rate determinations.

28. Retain an independent third-party entity to conduct a representative labor time study to determine an appropriate allocation of internal lobbyist labor, support

staff, and associated costs that should be accounted for in operating and nonoperating accounts based on time spent by employees engaged in the activities. Provide the study results to audit staff within 180 days of the date of the final audit report.

29. Include the results of the labor time study in the determination of lobbying-related labor cost allocations as of January 1, 2016.

30. Implement policies and procedures to perform a labor time study biennially using an independent third-party or internal company resources that are able to attest to the results of the study. Revise the lobbying-related labor cost allocations based on the results of the study.

Nonutility Expenses in Operating Accounts

31. Develop and implement written policies, procedures, and controls to ensure proper accounting and reporting of nonutility expenses.

32. Provide training for employees involved in the invoicing process on Commission accounting requirements and the impact of the accounting on cost-of-service rate determinations.

33. Within 60 days of receiving the final audit report, provide documentation supporting the analysis performed of invoiced expenses recorded to administrative and general (A&G) accounts in 2014 that identified misclassified nonutility expenses included in A&G accounts. Develop an estimate of misclassified nonutility expenses accounted for in operating accounts in 2011 through 2013 and 2015.

34. Implement policies and procedures to provide periodic audits or reviews of A&G transactions by external or internal auditors.

35. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the improper inclusion of identified and estimated nonutility expenses in charges to wholesale power and transmission customers during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made. Include the results of the invoice analysis in the refund analysis.

36. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

37. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

E. Implementation of Recommendations

Audit staff further recommends that Duke Companies submit the following for audit staff's review:

- A plan for implementing the audit recommendations within 30 days after the final audit report is issued;

- Quarterly reports describing progress in completing each corrective action recommended in the final audit report. Quarterly nonpublic submissions should be made no later than 30 days after the end of each calendar quarter, beginning with the first quarter after the final audit report is issued, and continuing until all recommended corrective actions are completed; and

- Copies of any written policies and procedures developed in response to recommendations in the audit report. These documents should be submitted in the first quarterly filing after Duke Companies complete such policies and procedures.

II. Background

A. Merger of Duke Energy and Progress Energy

On January 10, 2011, Duke Energy and Progress Energy announced their intention to merge in a stock-for-stock transaction under which Progress Energy would become a wholly owned subsidiary of Duke Energy, and the shareholders of Progress Energy would become shareholders of Duke Energy. At the time, the transaction was valued at over $31 billion. The merger was poised to create the largest U.S. electric utility in history with over seven million electric customers and operations in six states.

Following the announcement, on April 4, 2011, Duke Energy, Progress Energy, and their public utility subsidiaries (collectively, Duke Companies) filed an application with the Commission seeking authorization for the merger transaction under section 203 of the Federal Power Act (FPA)[3] and Part 33 of Commission regulations.[4] To receive authorization for the transaction, the companies committed to hold transmission and wholesale requirements customers harmless from the costs of the transaction for five years. The companies also contended that the transaction would not adversely affect competition, and thus there were no market power concerns associated with the transaction.

On September 30, 2011, the Commission found that the transaction, as proposed in the application, would result in significant screen failures in the horizontal market power analysis and have an adverse effect on competition.[5] As such, the Commission authorized the transaction subject to conditions. Among other things, the transaction was conditioned on Duke Companies holding transmission and wholesale requirements customers harmless from the costs of the transaction, and submitting proposed market power mitigation measures that the Commission approves. The Commission advised Duke Companies that sufficient mitigation measures could include membership in a regional transmission organization, implementing an independent coordinator of transmission arrangement, actual or virtual divestiture of generation, and/or transmission upgrades to provide greater market access to third-party energy suppliers.

Further, the Commission stated that the hold harmless commitment included all merger transaction costs, not only costs related to consummating the transaction.[6] To recover merger transaction costs through wholesale requirement or transmission rates, the

[3] 16 U.S.C. § 824b (2012).

[4] 18 C.F.R. Part 33.

[5] Merger Order, 136 FERC ¶ 61,245 at PP 145-146.

[6] *Id.* P 169.

companies were required to submit a filing to the Commission that identified merger costs to be recovered and demonstrated that the costs were exceeded by savings produced by the transaction.[7] Duke Companies did not submit a filing to recover merger transaction costs during the audit period. However, as discussed in detail below, the companies recovered merger transaction costs through rates charged.

Consistent with the Commission's merger authorization condition that required Duke Companies to submit proposed market power mitigation measures for approval, the companies submitted an initial compliance filing on October 17, 2011, which proposed to mitigate market power through virtual divestiture of generation. The filing proposed a must-offer obligation under which Duke Companies would sell specified quantities of energy at cost-based rates to entities directly or indirectly serving load in the DEC and DEP Balancing Authority Areas (BAAs). The Commission rejected the filing on the grounds that the market power mitigation proposals did not remedy the market power concerns identified in the Merger Order.[8]

A revised compliance filing was submitted by Duke Companies on March 26, 2012 that proposed permanent and interim market power mitigation measures. To permanently mitigate market power, Duke Companies proposed to build seven transmission expansion projects (TEPs), expedite completion of an eighth project that was already planned, and set aside 25 MW of transfer capacity on their transmission systems for use by third parties (Stub Mitigation). During construction of the TEPs, as an interim measure to protect against potential market power concerns, Duke Companies proposed to enter into power sale agreements with three unaffiliated firms – Cargill Power Marketing, EDF Trading, and Morgan Stanley Capital Markets – to which the companies would sell power during all periods requiring mitigation. The companies also proposed to hire an independent monitor, Potomac Economics Ltd. (Potomac Economics), to verify compliance with the provisions of the power sale agreements.

The Commission accepted the revised compliance filing on June 8, 2012, subject to certain revisions and conditions, which included, among other things, requirements to hold customers harmless from the cost of the mitigation actions and to expand Potomac Economics' duties to verify that the TEPs were completed within the prescribed scope and timeline.[9] The merger was consummated on July 2, 2012.

On December 6, 2013, after the merger was consummated, Duke Companies submitted a motion to supplement its March 26, 2012 compliance filing, due to newly identified information that affected calculation of the impact of the market power

[7] *Id.* P 170.

[8] *Duke Energy Corp.*, 137 FERC ¶ 61,210 (2011).

[9] *See* June 8 Compliance Order, 139 FERC ¶ 61,194 at P 113.

mitigation measures. In the filing, Duke Companies offered to increase the Stub Mitigation by 104 MW (thereby raising the total amount of the transmission set-aside to 129 MW), repair out of service phase-shifting transformers at DEC's Rockingham substation and return them to service, and operate the transformers so as to create additional import capability on the transmission system. The Commission granted the motion and accepted the supplementary compliance filing subject to conditions on October 29, 2014.[10] Moreover, the Commission reiterated its requirement that transmission and wholesale requirements customers be held harmless from costs associated with repairing the transformers and returning them to service.

B. Duke Energy's Public Utility Subsidiaries

During the audit period, the Duke Companies provided electricity service in portions of North Carolina, South Carolina, Florida, Indiana, Ohio, and Kentucky. DEO and DEK also provided natural gas service in portions of Ohio and Kentucky. The following describes the services provided by each company, its open access transmission tariff (OATT), membership in an independent system operator (ISO) or regional transmission organization (RTO), transmission formula rate, and market-based rate authority.

Duke Energy Carolinas, LLC

DEC is a vertically integrated public utility that generates, transmits, distributes, and sells electricity to 2.5 million customers in a 24,000 square mile service area in North and South Carolina. DEC owns 8,302 miles of transmission lines and 19,600 MW of generating capacity.

DEC provided open access transmission service under a Commission-approved OATT at cost-based stated rates from 1995 through 2011.[11] In 2011, DEC began recovery of its transmission service cost pursuant to a formula rate that became effective June 1, 2011.[12] However, on March 26, 2012, in connection with the merger transaction, DEC, DEP, and DEF filed for approval of a Joint OATT under section 205 of the FPA and Part 35 of the Commission's regulations. The filing was conditionally accepted by the Commission on June 8, 2012.[13]

[10] October 29 Compliance Order, 149 FERC ¶ 61,078 (2014).

[11] *Duke Power Co.*, 73 FERC ¶ 61,309 (1995) (Duke Power Order).

[12] *Duke Energy Carolinas, LLC*, 137 FERC ¶ 61,058 (2011).

[13] *Duke Energy Corp.*, 139 FERC ¶ 61,193 (2012).

The Joint OATT provided for transmission service at non pancaked rates for transactions involving the combined transmission systems of the companies. DEC's transmission formula rate is incorporated as Schedule 10-B of the Joint OATT. DEC's formula rate implementation protocols are incorporated as Exhibit A of the Joint OATT, and the formula rate template and formula rate principles are contained in Exhibit B. DEC does not belong to an ISO or RTO.

DEC has wholesale power sale agreements with cost-based rates determined under a formula, and it has Commission authorization to make wholesale sales at market-based rates outside its and DEP's BAAs and Peninsular Florida.

Duke Energy Progress, LLC

DEP is a vertically integrated public utility that generates, transmits, distributes, and sells electricity to 1.5 million customers in a 32,000 square mile service area in North and South Carolina. DEP owns 6,981 miles of transmission lines and 12,200 MW of generating capacity.

DEP provided open access transmission service under a Commission-approved OATT at cost-based stated rates from 1996 through 2008. In 2008, DEP began recovery of its transmission service cost pursuant to a formula rate that became effective July 1, 2008.[14] Since the merger, DEP has provided transmission service under the Joint OATT with DEC and DEF. DEP's transmission formula rate is incorporated in Attachment H of the Joint OATT. The formula rate template is incorporated as Attachment H-1 of the Joint OATT, and the implementation protocols as Attachment H-2. DEP does not belong to an ISO or RTO.

DEP has wholesale power sale agreements with cost-based rates determined under a formula, and it has Commission authorization to sell energy and capacity at market-based rates outside its and DEC's BAAs and Peninsular Florida.

Duke Energy Florida, LLC

DEF is a vertically integrated public utility that generates, transmits, and delivers electricity to 1.7 million customers in a 13,000 square mile area in central and southern Florida. DEF owns 4,424 miles of transmission lines and 1,200 MW of generating capacity.

[14] *Carolina Power and Light Co.*, Docket No. ER08-889-000 (June 27, 2008) (delegated letter order).

DEF provided open access transmission service under a Commission-approved OATT at cost-based stated rates from 1996 through 2008. In 2008, DEF began recovery of its transmission service cost pursuant to a formula rate that became effective January 1, 2008.[15] Since the merger, DEF has provided transmission service under the Joint OATT with DEC and DEP. DEF's transmission formula rate is incorporated as Schedule 10-A of the Joint OATT. The implementation protocols are designated as Schedule 10-A.1 of the Joint OATT, and the formula rate template as Schedule 10-A.2. DEF does not belong to an ISO or RTO. Additionally, DEF has Commission authorization to sell energy and capacity outside the DEC and DEP BAAs and Peninsular Florida.

Duke Energy Indiana, LLC

DEI is a vertically integrated utility that generates, transmits, distributes, and sells electricity to 810,000 customers within a 23,000 square mile service territory in central, north central, and southern Indiana. DEI owns 7,500 MW of generating capacity and 4,815 miles of transmission lines.

DEI became a member of the Midcontinent Independent System Operator, Inc., (MISO) in 1997 and recovered its cost of transmission service pursuant to cost-based stated rates. In 1998, DEI began to recover its transmission service cost pursuant to a transmission formula rate. DEI's transmission formula rate template is included at Attachment O of the MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff. Additionally, DEI has Commission authorization to sell power at market-based rates outside the DEC and DEP BAAs and Peninsular Florida.

Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.

DEO is the direct parent of DEK. The companies are combination electric and gas utilities that transmit, distribute, and sell electricity at retail and wholesale, and distribute and sell natural gas at retail in southwestern Ohio and northern Kentucky, respectively. DEO owns 1,879 miles of transmission lines. The company divested its generating assets pursuant to Ohio's electric restructuring program and received Commission authorization for the divestiture.[16] DEK owns 102 miles of transmission lines and about 1,200 MW of generating capacity.

[15] *Florida Power Corp.*, Docket No. ER08-105-000 (Dec. 17, 2007) (delegated letter order).

[16] *See Dynegy Resource I, LLC*, 150 FERC ¶ 61,232 (2015).

DEO and DEK were members of MISO until January 1, 2012, when they withdrew their membership and joined PJM Interconnection, L.L.C. (PJM).[17] The companies recover transmission service costs pursuant to a transmission formula rate under the PJM OATT. DEO and DEK's transmission formula rate is incorporated as Attachment H-22 of the PJM OATT. The formula rate template is incorporated as Attachment H-22A of the OATT, and the implementation protocols as Attachment H-22B. Additionally, DEO and DEK have Commission authorization to sell power at market-based rates outside the DEC and DEP BAAs and Peninsular Florida.

[17] The Commission conditionally authorized the move in an order issued October 21, 2010. *See Duke Energy Ohio, Inc.*, 133 FERC ¶ 61,058 (2010).

III. Introduction

A. Objectives

The audit evaluated Duke Companies' compliance with conditions established in the Merger Order and associated orders on compliance, requirements of each company's transmission formula rate tariff, and accounting and financial reporting regulations. The audit covered the period January 1, 2011 through January 31, 2016.

B. Scope and Methodology

Audit staff performed specific actions to facilitate the audit and evaluate compliance with the audit objectives. Audit staff also reviewed the effectiveness of Duke Companies' compliance program in relation to the audit objectives and other key factors. To address overall audit objectives, audit staff:

- Conducted an extensive review of publicly available materials to understand the companies' corporate structure and organization, operations, financial accounting and reporting activities, and other key regulatory and business activities, both before and after the merger. Examples of materials and documentation reviewed include Commission rules, regulations, and orders, Form No. 1 reports, FERC Form No. 65, Notification of Holding Company Status, formula rate filings, the Commission's enforcement hotline calls and company self-reports, company-related web sites, and relevant media sources. This also included a review of filings with other government agencies, such as the Securities and Exchange Commission Forms 10-K and 10-Q, Annual and Quarterly Reports;

- Evaluated the companies' internal policies and procedures relevant to the audit objectives;

- Conferred with other Commission staff on various compliance issues to ensure audit findings were consistent with Commission precedent and policy. For example, audit staff communicated with staff from other divisions within the Office of Enforcement and staff from the Office of Energy Market Regulation and Office of General Counsel;

- Conducted two site visits to Duke Energy's headquarters in Charlotte, NC. The visits enabled audit staff to further understand the company's corporate structure, functions, operations, accounting systems and practices, transmission planning and cost-estimating procedures, formula rate, internal audit function, and regulatory and corporate compliance programs. While on site, audit staff interviewed employees and managers responsible for performing tasks within the audit scope, sampled and tested documents to verify compliance with Commission orders related to merger conditions, accounting regulations, financial reporting, transmission formula rates, and related matters. Additionally, audit staff also interviewed compliance program staff, senior officials, internal auditors, and employees who fulfill day-to-day compliance activities for the purposes of carrying out regulatory oversight responsibilities;

- Conducted teleconferences to discuss audit objectives and scope, data requests and responses, technical and administrative matters, compliance concerns, and held a closing conference to discuss the completion of audit fieldwork and results; and

- Issued data requests to gather information not available through public means. This information related to internal policies and procedures, business practices, reporting activities, corporate compliance, internal and external audit reports, merger order conditions and compliance, transaction and operational data, and other pertinent information. Audit staff used this information as underlying support for testing and evaluating compliance with Commission requirements relevant to the audit scope and objectives.

Further, audit staff performed these specific actions to facilitate the testing and evaluation of compliance with relevant requirements for the audit scope areas. A summary of these actions follows.

Compliance with Merger Conditions

To evaluate compliance with the hold harmless and market power mitigation conditions established in the Merger Order and associated compliance orders, audit staff performed audit fieldwork applicable to the merger. Audit staff performed the following steps:

- Reviewed the merger application, supporting testimony and exhibits to understand the context, terms, and conditions of the merger proposal and commitment to hold transmission and wholesale requirements customers harmless from costs of the transaction. Reviewed intervenor comments and protests, and responses to the comments and protests, and also reviewed Duke Companies' compliance filings, intervenor responses, and answers to the responses;

- Evaluated Duke Companies' responses to Commission staff's delegated data requests that sought information regarding the merger application and compliance filings;

- Examined the companies' policies and procedures associated with tracking and accounting for merger transaction costs incurred prior to and following consummation of the merger;

- Performed a comparative analysis of Duke Energy and Progress Energy's accounting for costs of the merger prior to and after its consummation and the companies' policies associated with the accounting;

- Reviewed actions taken by the companies to maintain compliance with merger conditions;

- Analyzed the companies' procedures to ensure compliance with hold harmless conditions and to account for merger transaction costs;

- Conducted sample-based tests of internal costs and external contracted costs incurred by the companies to assess the accounting for the costs and the impact on wholesale rate determinations;

- Obtained information on staff involved in merger activities, including employee names, positions, salaries, work performed on merger activities, and time spent on merger-related activities;

- Reviewed documentation and supporting evidence of merger transaction costs and performed substantive tests of sample data;

- Inspected reports submitted by Potomac Economics regarding the Rockingham phase shifters and other relevant Commission filings;

- Evaluated expenses incurred to repair the Rockingham phase shifters to assess the accounting for the costs and impacts on wholesale rate determinations; and

- Examined costs incurred to operate the TEPs – including the Rockingham phase shifters – from 2012 through Q1 2015 to evaluate the accounting used to record cost of activity and the resulting impact on wholesale rate determinations.

Furthermore, audit staff conducted the following additional steps to evaluate Duke Companies' compliance with the market power mitigation conditions:

- Reviewed the companies' contract with Potomac Economics to ascertain whether the independent monitor had sufficient oversight authority and timely access to data needed to monitor compliance with interim and permanent market power mitigation measures;

- Examined the quarterly independent monitoring reports prepared by Potomac Economics detailing Duke Companies' compliance with interim and permanent market power mitigation conditions;

- Interviewed personnel responsible for reporting the status of TEP construction to Potomac Economics, and reviewed a sample of email communications between the parties;

- Interviewed personnel involved with TEP planning, engineering and design, purchasing and contracting, construction, and project management to verify that the projects were completed as required and to ascertain the amount of labor time employees spent on the projects;

- Identified scope changes made to the TEP plans and assessed the impact of changes on project cost and expected performance of the transmission system;

- Examined a sample of information that Potomac Economics relied on to conclude that the TEPs were placed into service. This information included data from the supervisory control and data acquisition (SCADA) system on the operation of the constructed projects and associated work orders;

- Analyzed photographs of TEP equipment nameplates for asset identification and facility ratings for a sample of major equipment installed, and compared nameplate information to construction work orders and internal company correspondence related to the TEPs;

- Reviewed Duke Companies' written procedures that governed implementation of the power sales agreements required by the Commission's interim market power mitigation measures. Also, interviewed personnel responsible for developing and implementing the agreements, and reviewed Potomac Economics' seasonal and event-based reports to the Commission on the company's performance under the agreements;

- Analyzed a sample of transaction data on power sales DEC and DEP made under the power sale agreements and reviewed transmission schedules on the Open Access Same-time Information System (OASIS) to verify the energy was scheduled and delivered;

- Interviewed power marketing personnel to gain information on operating procedures and processes used to comply with the requirement to set aside firm transmission capacity on the DEC-DEP interface (i.e., Stub Mitigation requirement);

- Reviewed Potomac Economics' reports on the Stub Mitigation requirement and analyzed a sample of data from OASIS regarding transmission offerings and requests for firm transmission service on the DEC-DEP interface;

- Evaluated the DEC-DEP Joint Dispatch Agreement (JDA) and associated operating procedures to understand the methods used to forecast load and determine the mix of generating resources needed to meet load demand on daily and weekly bases;

- Interviewed power marketing employees responsible for scheduling power between the DEC and DEP BAAs, and examined a sample of transactions that involved dispatch of generating resources, reserving and scheduling transmission service consistent with the JDA, and operating the respective BAAs separately. Also, tested a sample of OASIS transmission reservations and schedules to evaluate DEC and DEP's reservations of point-to-point and network transmission service to transmit energy and capacity between the two BAAs; and

- Identified instances in which DEC and DEP used network transmission to deliver power to their respective BAAs, and evaluated these transactions to assess compliance with conditions that restricted certain transactions in the BAAs.

Transmission Formula Rates

To evaluate compliance with the requirements of each company's transmission formula rate tariff, audit staff:

- Reviewed the initial applications filed seeking approval of each company's transmission formula rate tariff, intervenor responses to the filings, any associated settlement agreements with wholesale customers and interested parties, and the Commission orders that approved the transmission formula rate tariffs;

- Examined the transmission formula rate templates and all appendices and attachments used to compute key inputs to the annual transmission revenue requirement and associated formula rate protocols;

- Interviewed employees responsible for populating each public utility's transmission formula rate template, verifying data and calculations, and reviewing and obtaining management approval of the calculated transmission service rates;

- Assessed the adequacy of management oversight and verification controls that support performance of key activities;

- Evaluated data responses and conducted conference calls to understand the accounting for major items affecting the formula rate, including miscellaneous deferred debits, income taxes, and others. Also, reviewed these items to determine compliance with relevant accounting regulations, instructions, and definitions;

- Reviewed annual informational and true-up filings submitted after the initial rate years and during the audit period. Reconciled the Form No. 1 data with formula rate calculations and evaluated discrepancies. Conducted a detailed analysis of supporting worksheets and attachments to evaluate the calculation of transmission formula rate inputs;

- Analyzed footnotes included in each company's Form No. 1 to determine whether information disclosed provided for a reconciliation of publicly available data to balances used to calculate the transmission service rates;

- Performed procedures to verify that transmission formula rate inputs were supported by data reported in each company's Form No. 1;

- Evaluated the companies' accounting for merger transaction costs by assessing documented policies, operating processes, and procedures, and tested a sample of invoices and work orders that included merger activities and associated costs. Analyzed the accounting for the costs and the impact on transmission rate determinations;

- Checked plant balances used to calculate transmission revenue requirements, sampled work order charges included in construction work in progress and plant balances, and performed tests on amortized pre-commercial costs;

- Tested a sample of depreciation accruals on utility plant to assess the depreciation rates applied to the plant; and

- Performed substantive tests on a sample of invoices and work orders that included nonutility expenses, and evaluated the impact of identified misclassified items on transmission rate determinations.

Accounting and Reporting

To evaluate compliance with the Commission's accounting and reporting regulations in the USofA under 18 C.F.R. Parts 101 and 141, audit staff performed the following with respect to the merger:

- Conducted interviews and teleconferences and met with company staff to discuss accounting policies, procedures, and practices. These interviews included discussions with employees involved in the operation of each public utility subsidiary's financial accounting systems to assess the adequacy of accounting and reporting oversight controls related to the merger, and employees in leadership positions responsible for day-to-day oversight of merger activities to understand how merger-related labor was reported on timesheets;

- Examined procedures for preparing, reviewing, and obtaining management approval of the Form No. 1 reports. Reviewed disclosures in the reports to understand major accounting policies;

- Reviewed and evaluated the processes, procedures, and controls the companies used before and after merger consummation to track and account for merger transaction costs;

- Evaluated the Form No. 1 and Securities and Exchange Commission 10-K notes and disclosures related to tracking, accounting, and reporting merger transaction costs;

- Analyzed the companies' accounting entries that recorded merger-related labor, goodwill, TEP project costs and impairments, and the income tax effects of the transaction;

- Reviewed third-party lobbying expenditure disclosures, press articles, meeting schedules, and agendas of internal lobbyists. Interviewed internal lobbyists and support staff to understand the nature and extent of the companies' lobbying activities;

- Tested a sample of work orders, invoices, and associated accounting detail records that support internal lobbyists' labor costs incurred;

- Assessed the impact on wholesale rates of merger and other costs incurred by the companies that were reported in the Form No. 1;

- Tested a sample of FERC accounts for compliance with the Merger Order as well as the companies' internal policies and procedures; and

- Evaluated certain income statement and balance sheet accounts and balances reported in the companies' Form No. 1 reports for 2012 through 2014.

IV. Findings and Recommendations

1. Accounting for Merger Transaction Costs

Duke Companies did not file merger transaction accounting entries with the Commission as required by the Merger Order, and the companies recorded merger transaction costs in operating accounts, contrary to the Commission's long-standing policy that such costs be recorded in nonoperating accounts. By not filing the accounting entries, Duke Companies prevented Commission review of the merger accounting and correction of any entries that were not in accordance with Commission accounting requirements.

Pertinent Guidance

The Commission's September 30, 2011 order conditionally authorizing the Proposed Transaction established the following requirement concerning the submission of accounting entries related to the merger:

> To the extent any applicant that is subject to the Commission's Uniform System of Accounts records any aspect of the Proposed Transaction in its accounts, it is directed to file its accounting entries with the Commission within six months of the consummation of the Proposed Transaction. Further, if the accounting entities are recorded six months after the consummation of the Proposed Transaction, the applicant must file those accounting entries with the Commission within 60 days from the date they were recorded. The accounting submission must provide all accounting entries related to the Proposed Transaction, including narrative explanations describing the basis, and the rate impact, of such entries.[18]

The Commission's long-standing precedent stipulates that transaction costs incurred by public utilities associated with a merger are nonoperating in nature and should be charged to Account 426.5, Other Deductions, to the extent the costs are not retained by the parent holding company. For example, in *Allegheny Energy, Inc.*, the Commission stated in part:

> The Commission has previously determined that merger transaction costs are considered non-operating in nature and should be recorded in

[18] Merger Order, 136 FERC ¶ 61,245 at P 190.

Account 426.5, Other Deductions.[19]

18 C.F.R. Part 101, Account 426.5, Other Deductions, states:

> This account shall include other miscellaneous expenses which are nonoperating in nature, but which are properly deductible before determining total income before interest charges.

18 C.F.R. Part 101, General Instruction No. 5, Submittal of Questions, states:

> To maintain uniformity of accounting, utilities shall submit questions of doubtful interpretation to the Commission for consideration and decision.

Background

In the Merger Order, the Commission authorized Duke Companies to merge, subject to conditions. With respect to accounting, the Merger Order stated that if any Duke Energy subsidiary subject to the USofA recorded any aspect of the merger on its books, the subsidiary must file the accounting entries with the Commission within 60 days of consummation of the transaction. The Commission noted that such accounting entries include entries related to transaction costs, merger premiums, acquisition adjustments, goodwill, or any cost related to the merger.[20]

Moreover, pursuant to long-standing Commission precedent, merger transaction costs are considered nonoperating in nature and are required to be recorded to Account 426.5, Other Deductions. The text of Account 426.5 states that the account shall include expenses that are nonoperating in nature. Audit staff evaluated Duke Companies' accounting for the merger and found that the companies recorded merger transaction costs on their books. Further, contrary to the requirements of the Merger Order and Commission accounting rules, Duke Companies neither filed accounting entries with the Commission that reflected the recording of the transaction costs on the companies' books nor accounted for nonoperating merger transaction costs in Account 426.5.

[19] *See Allegheny Energy, Inc.*, 133 FERC ¶ 61,222, at P 73 (2010). *See also Midwest Power Systems, Inc. and Iowa-Illinois Gas and Elec. Co.*, 71 FERC ¶ 61,386, at 62,509 (1995); *MidAmerican Energy Co. and MidAmerican Energy Holdings Co.*, 85 FERC ¶ 61,354, at 62,370 (1998); and *Wis. Elec. Power Co.*, 74 FERC ¶ 61,069, at 61,192 (1996).

[20] Merger Order, 136 FERC ¶ 61,245 at n. 414.

Duke Companies collectively incurred over $1 billion in merger costs and recorded the costs on their Form No. 1 reports from 2011 through October 30, 2015. The costs were accounted for in numerous operating plant and expense accounts, including: A&G expense; payroll tax; customer account expense; transmission, distribution, and production operating and maintenance expense; and other accounts.

Duke Energy explained that it interpreted the Merger Order to require submittal of accounting entries only if a subsidiary used the purchase method of accounting and increased the book value of assets for goodwill acquired in the transaction. However, the Merger Order did not require the companies to file accounting entries only if they used the purchase method of accounting or increased the book value of assets for goodwill. To the contrary, the Merger Order stated that if *any entity* subject to the USofA recorded *any aspect* of the merger on its books, it must file its accounting entries with the Commission. The Merger Order further clarified that such accounting entries included entries related to transaction costs, merger premiums, acquisition adjustments, goodwill, or any cost related to the merger.

All of Duke Energy's public utility subsidiaries were subject to the Commission's USofA, therefore the companies should have filed accounting entries. By not filing the accounting entries, Duke Companies prevented Commission review of the merger accounting and correction of any entries not in accordance with Commission accounting requirements.

Furthermore, Duke Companies should have recorded merger transaction costs incurred to effectuate the merger in Account 426.5 rather than in operating accounts consistent with the text of Account 426.5 and Commission precedent.[21] Audit staff found that prior to March 2012, both Duke Energy and Progress Energy recorded merger transaction costs in operating accounts. However, in March 2012, Progress Energy transferred its merger transaction costs to Account 426.5, due to its interpretation of a Commission merger order that required such accounting. Duke Energy did not implement a similar reclassification of its merger transaction costs. Duke Energy explained that it believed costs associated with the merger were appropriately recorded in operating accounts.

[21] Post-merger integration cost (i.e., cost incurred following consummation of a merger, in which the assets, personnel, and business activities of the entities participating in the merger are combined) are recordable to operating accounts; however, the cost would be subject to the Commission's hold harmless commitments and prohibited from recovery in jurisdictional rates.

In April 2012, Duke Energy's external auditors questioned its accounting of the merger transaction costs. The external auditors informed Duke Energy of the Commission's merger accounting policy, which the auditors interpreted as requiring merger transaction costs to be recorded below-the-line in Account 426.5. Duke Energy disagreed with the auditors' interpretation. Rather than adjusting its accounting, Duke Energy and its external auditors agreed that Duke Energy's management representation letter would be revised. The letter is a signed attestation by Duke Energy management of the accuracy of its financial statements. The letter was revised to include a statement that Duke Energy was aware of Commission orders that indicated merger transaction costs should be recorded in Account 426.5, but Duke Energy nonetheless believed that its classification of merger transaction costs in operating accounts was appropriate.

The Duke Companies were required to file the accounting entries with the Commission as directed in the Merger Order. The companies' improper accounting for merger transaction costs contributed to the inappropriate recovery of merger-related internal labor and outside service costs through charges to Commission-jurisdictional customers. To the extent Duke Companies was uncertain about the appropriate accounting for the transaction, the companies should have submitted accounting questions of doubtful interpretation to the Commission for consideration and decision. The Commission expects Duke Companies, and all entities that have a reporting requirement for transactions under FPA section 203, to fully comply with the orders approving such transactions. Duke Companies' lack of compliance with the Merger Order reporting requirement is a very serious matter.

Recommendations

We recommend Duke Companies:

1. Revise accounting policies and procedures to appropriately account for merger transactions consistent with Commission accounting requirements.

2. Develop written policies and procedures to timely identify proposed accounting transactions that would trigger a notification to the Commission.

3. Develop written policies and procedures to submit accounting questions of doubtful interpretation to the Commission.

4. Provide training to employees on compliance with the merger cost accounting conditions and the revised policies, procedures, and controls for complying with the conditions. Also, develop a training program that supports the provision of periodic training in this area.

2. Merger Transaction Internal Labor Costs

Duke Companies improperly included approximately $31.4 million of merger transaction internal labor costs in wholesale power and transmission formula rate service cost determinations without first submitting a section 205 filing demonstrating that the costs were offset by quantified savings produced by the merger. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $17.5 million.

Pertinent Guidance

The Commission's Merger Order states in part:

> We accept Applicants' commitment to hold transmission and wholesale requirements customers harmless for five years from costs related to the Proposed Transaction. We interpret Applicants' hold harmless commitment to include all transaction-related costs, not only costs related to consummating the transaction.
>
> If Applicants seek to recover transaction-related costs through their wholesale power or transmission rates within the next five years, they must submit a compliance filing that details how they are satisfying the hold harmless requirement. If Applicants seek to recover transaction-related costs in an existing formula rate that allows for such recovery within the next five years, then that compliance filing must be filed in the section 205 docket in which the formula rate was approved by the Commission, as well as in the instant section 203 docket. In such filings, Applicants must: (1) specifically identify the transaction-related costs they are seeking to recover; and (2) demonstrate that those costs are exceeded by quantified savings resulting from the transaction, in addition to any requirements associated with filings made under section 205.[22]

The Commission's June 8, 2012 order accepting Duke Companies' revised compliance filing states in part:

> [T]he Commission will require Applicants to hold transmission and wholesale requirements customers harmless from the costs of the Transmission Expansion Projects in accordance with the hold harmless commitment, as set forth in the Merger Order.[23]

[22] Merger Order, 136 FERC ¶ 61,245 at PP 169-170.

[23] June 8 Compliance Order, 139 FERC ¶ 61,194 at P 91.

The Commission's October 29, 2014 order denying rehearing and granting a motion to supplement compliance filing states in part:

> [T]he Commission requires Applicants to hold transmission and wholesale requirements customers harmless for five years from costs related to the Phase Shifters.[24]

Background

On April 4, 2011, Duke Energy, Progress Energy, and their public utility subsidiaries (collectively, Duke Companies) filed an application seeking Commission authorization of a proposal to merge under section 203 of the FPA and Part 33 of Commission regulations. In the application, Duke Companies committed to exclude costs related to the merger from transmission and wholesale requirements customers' rates, except to the extent the companies demonstrated in a section 205 rate filing that merger-related savings were equal to or in excess of merger costs included in the rate filing. On September 30, 2011, the Commission issued an order authorizing Duke Companies to merge subject to conditions. Among other things, the Commission conditioned authorization on Duke Companies maintaining its commitment to hold transmission and wholesale requirements customers harmless from costs related to the merger. Pursuant to this condition, "[a]ll transaction related costs, not only costs related to consummating the transaction," were required to be excluded from rates charged.[25] To determine if Duke Companies complied with the hold harmless requirement, audit staff examined the companies' procedures for tracking and accounting for merger costs, and excluding the costs from rates.

To track costs incurred due to the merger, the companies established special accounting processes and procedures. Audit staff found that Duke Energy and Progress Energy did not account for merger costs using the same accounting treatment prior to consummation of the merger. Prior to consummation of the merger, Duke Energy accounted for merger transaction costs in above-the-line operating accounts, whereas Progress Energy accounted for the costs below-the-line in Account 426.5, Other Deductions.[26] However, after consummation of the merger, Progress Energy adopted Duke Energy's internal accounting policy for merger transaction costs and thereafter began accounting for incurred merger transaction costs in operating accounts.

[24] October 29 Compliance Order, 149 FERC ¶ 61,078 at P 81.

[25] Merger Order, 136 FERC ¶ 61,245 at P 169.

[26] Account 426.5, Other Deductions, 18 C.F.R. Part 101 (2015), provides for the recording of expenses that are nonoperating in nature, but which are properly deductible before determining total income before interest charges.

Duke Energy devised and distributed instructions to its public utility subsidiaries regarding accounting for merger costs, which it characterized as Costs to Achieve (CTA) the merger. Duke Energy defined CTA as "costs that are incremental and nonrecurring that would otherwise not have been incurred but for the merger or integration planning efforts."[27] The CTA instructions identified the accounting codes to be used to account for and track merger costs. The codes included the business and operating unit that incurred the cost, process, task, project ID, and other details associated with activities that involved the incurrence of merger costs. The CTA instructions were communicated to managers and staff assigned to work on the merger, and employees were trained on use of the accounting codes. Duke Energy's shared services accounting group retrieved merger cost data from the general ledgers of the public utility subsidiaries, reviewed charges for reasonableness, and compared actual and budgeted costs as part of its monthly reporting process.

Duke Energy's shared services accounting group developed additional procedures to exclude certain merger costs from wholesale power and transmission formula rate determinations of the public utility subsidiaries. The procedures included preparation of monthly spreadsheets identifying merger costs included in each subsidiary's operating accounts as reported in the Form No. 1. The rate staff of each public utility subsidiary was instructed to subtract the merger costs from operating accounts in the Form No. 1 that were used to compute the company's transmission formula rate. The procedures were designed to prevent merger costs reported in operating accounts from being incorporated in wholesale power and transmission formula rate determinations.

As a result of these procedures under which merger-related internal labor costs were not treated as CTA, audit staff found that Duke Companies' wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $17.5 million due to the inclusion of merger transaction internal labor costs in wholesale power and transmission rate determinations without first making a section 205 filing with the Commission as the Merger Order required. The improper charges included an estimated $17.2 million through inclusion of internal labor costs incurred in merger transaction and integration activities, and over $300,000 through inclusion of

[27] This included costs incurred in developing, executing, and obtaining approvals for the merger as well as incremental integration costs, but did not include merger-related internal labor costs Duke Companies considered non-incremental. For example, the costs included severance payments, employee relocation and retention costs, bonuses paid to employees for their work on the merger, investment banking and advisory fees, state and Federal regulatory expenses, costs for integrating accounting and information technology systems, transmission systems, fuel and dispatch systems, as well as transition costs, mitigation/concession costs, depreciation expenses for merger projects, and fees paid to providers of transmission service between the regulated utilities.

internal labor costs incurred to construct and operate the transmission expansion projects (TEPs), and repair and operate the Rockingham phase shifters.

Merger Transaction Internal Labor

During fieldwork, audit staff determined that Duke Energy excluded merger transaction internal labor from its definition of CTA and its CTA coding procedures. Duke Energy acknowledged that employees spent substantial time on merger activities. However, the company contended that employees performed merger activities in addition to their regular responsibilities and, therefore, no incremental internal labor costs were incurred due to the merger. Based on a belief that the hold harmless obligation applied only to incremental merger costs, Duke Energy instructed employees not to use the special CTA codes to report time devoted to merger activities on their timesheets. Consequently, public utility subsidiaries did not track all merger transaction internal labor costs or exclude all such costs from wholesale power and transmission formula rate cost computations. As a result, the subsidiaries improperly included some merger transaction internal labor costs in wholesale power and transmission formula rate determinations and inappropriately charged the costs to customers.

Contrary to Duke Energy's interpretation, the Merger Order required Duke Companies to hold customers harmless from "*all* merger transaction costs," and did not limit this requirement only to costs Duke Energy considered incremental. Duke Energy's assertion that its hold harmless obligation extended only to incremental costs must be made within a section 205 proceeding where it and other interested parties will have an opportunity to assess all evidence that supports or contradicts such a position. By excluding internal labor from its CTA tracking and reporting procedures, Duke Energy did not have the ability to determine the proportion of employee labor costs devoted to merger-related tasks, as opposed to utility-related tasks, the cost of which are appropriately recovered in rates. Moreover, even in the absence of detailed time reporting and accounting data, the companies were nonetheless prohibited from including these merger transaction costs in rate determinations without first receiving Commission authorization to do so in a section 205 proceeding in accordance with Merger Order requirements.

Since Duke Companies did not track all merger transaction internal labor costs, audit staff issued data requests and interviewed company employees during site visits and conference calls to develop its own estimate of the amount of merger transaction internal labor costs Duke Companies incurred and included in transmission formula rate charges. The information audit staff obtained confirmed that company employees spent substantial amounts of time working on the merger, as Duke Energy acknowledged. For example, Duke Energy reported in data responses that over 2,400 employees were engaged in merger activities from mid-2010 through present. The total included more than 2,300 employees who participated in over 300 merger integration projects performed to upgrade and integrate the companies' information technology, human resources, finance, and accounting systems and functions. About 140 employees were engaged in merger planning and evaluation, preparing and supporting merger applications and post-merger litigation, and developing and implementing measures to mitigate market power due to the merger. Audit staff found through assessment of data response information and interviews of company staff, that certain of these employees worked full time on the merger for the duration of their projects, while others devoted 50 percent or more of their time to assigned merger activities. Moreover, detailed analysis of integration projects with the largest budgets indicated that the assigned employees were heavily engaged in the projects for prolonged periods of time.

Audit staff used this information, interviews with employees engaged in merger activities, employees' salary information procured from data responses, and salary estimates found on publicly available sources to approximate the amount of internal labor costs incurred due to the merger. Audit staff estimated that the Duke Companies incurred between $55 million and $75 million of internal labor costs related to the merger, including salaries and benefits.

Audit staff then asked Duke Energy to provide its own estimate of the internal labor costs associated with each merger activity and a breakdown by FERC account. As the table below shows, Duke Energy estimated that $78.8 million in merger transaction internal labor costs were incurred to perform four primary merger tasks. Duke Energy's estimate exceeded audit staff's high-range estimate of internal labor costs.

		A	B
Row	**Merger Tasks**	**Duke Companies' Estimated Internal Labor Cost (Million $)**	**Estimated Internal Labor Included in the Revenue Requirements of Wholesale Power and Transmission Rates (Million $)**
1	Merger Planning, Evaluation, Due Diligence	2.3	0.1
2	Preparation and Support for Regulatory Applications and Post-Merger Litigation	3.9	0.2
3	Development and Implementation of Measures to Mitigate Market Power	0.6	0.03
4	Planning, Management, and Execution of Merger Integration Projects	72.0	16.9
	Total	**78.8**	**17.2**

Of the $78.8 million in merger transaction internal labor costs estimated by Duke Energy, about $1.6 million of the costs were recorded in distribution operating and maintenance expense accounts that were not included in Commission-jurisdictional rate determinations, and $31.4 million was recorded in production and transmission operating and maintenance expense accounts incorporated in wholesale power and transmission formula rates. Duke Energy estimated that wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $17.2 million.[28] The remaining $45.8 million in merger transaction internal labor costs were charged to capital work orders for integration projects that are under construction and not yet completed. Duke Energy represented that these costs have been classified as CTA, and will be excluded from wholesale power and transmission formula rates when the projects are completed.

By including these merger-related tasks in its definition of CTA, Duke Energy acknowledged that the merger activities employees performed would not have been required in the absence of the merger. Since the work was not related to utility service, employee time engaged on the merger should have been excluded from transmission formula rate determinations. In accordance with the hold harmless commitment, to recover merger costs in their wholesale power or transmission rates, the companies were required to submit a section 205 filing with the Commission detailing costs to be recovered and demonstrating that the costs were offset by quantified savings produced by the merger. Duke Companies did not submit a section 205 filing; therefore, the companies should not have recovered the costs in rates charged.

TEP Operating Expenses

Duke Energy's public utility subsidiaries included an estimated $300,000 of merger transaction internal labor costs in the transmission customers' formula rate revenue requirement for costs related to the TEP projects from 2012 through 2015. This amount was incurred to repair and operate the Rockingham phase shifters. The $300,000 was recorded as transmission maintenance expenses in Account 570, Maintenance of Station Equipment. In accordance with Duke Companies' internal accounting policy, the companies neither characterize the costs as merger-related CTA nor exclude the costs from transmission formula rate determinations. As a result, the $300,000 was included in transmission formula rates, and thus a portion of these costs was inappropriately charged to transmission customers.

In its June 8 and October 29 Compliance Orders, the Commission explicitly directed Duke Companies to hold customers harmless from all costs related to the TEPs

[28] During the audit, DEC and DEP had about 20 wholesale power customers under service contracts with cost-based rates determined under a formula to which merger transaction internal labor costs were incorporated. As a result, a portion of the merger transaction labor costs included in the formula was charged to wholesale power customers.

and the Rockingham phase shifters, consistent with the hold harmless commitment established in the Merger Order. Duke Companies should not have included these internal labor charges in transmission formula rate determinations without first submitting a section 205 filing to the Commission that demonstrated that the costs were offset by quantified savings produced by the merger.

Recommendations

We recommend Duke Companies:

5. Revise all policies and procedures for tracking, accounting, and excluding merger transaction costs from wholesale power and transmission formula rates, including amounts previously charged to utility plant, accumulated deferred income taxes, construction work in progress with the associated capitalized cost of funds used during construction (AFUDC), and maintenance and operating expense accounts, and future charges to such accounts for any transaction to which a FERC hold harmless obligation applies. The revised procedures should hold customers harmless from all merger transaction costs consistent with requirements of the Merger Order. Among other things, the revised policies and procedures should include an annual review of each subsidiary's merger transaction cost adjustments as well as periodic evaluations within the year, as needed and appropriate.

6. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the inclusion of merger transaction internal labor and related costs in wholesale power and transmission formula rates during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

7. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

8. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

3. Merger Transaction Outside Services and Related Costs

Duke Companies incorrectly included $1.5 million of merger transaction outside services and related costs in wholesale power and transmission formula rate service cost determinations without first submitting a section 205 application demonstrating the costs were offset by quantified savings produced by the merger. In addition, the companies recorded the merger transaction costs in operating accounts, contrary to the Commission's long-standing policy that such costs be recorded in nonoperating accounts. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $745,000.

Pertinent Guidance

The Commission's Merger Order states in part:

> We accept Applicants' commitment to hold transmission and wholesale requirements customers harmless for five years from costs related to the Proposed Transaction. We interpret Applicants' hold harmless commitment to include all transaction-related costs, not only costs related to consummating the transaction.
>
> If Applicants seek to recover transaction-related costs through their wholesale power or transmission rates within the next five years, they must submit a compliance filing that details how they are satisfying the hold harmless requirement. If Applicants seek to recover transaction-related costs in an existing formula rate that allows for such recovery within the next five years, then that compliance filing must be filed in the section 205 docket in which the formula rate was approved by the Commission, as well as in the instant section 203 docket. In such filings, Applicants must: (1) specifically identify the transaction-related costs they are seeking to recover; and (2) demonstrate that those costs are exceeded by quantified savings resulting from the transaction, in addition to any requirements associated with filings made under section 205.[29]

The Commission's long-standing precedent stipulates that transaction costs incurred by public utilities associated with a merger are nonoperating in nature and should be charged to Account 426.5, Other Deductions, to the extent the costs are not passed on to the parent holding company. For example, in *Allegheny Energy, Inc.*, the Commission stated in part:

[29] Merger Order, 136 FERC ¶ 61,245 at PP 169-170.

> The Commission has previously determined that merger transaction costs are considered non-operating in nature and should be recorded in Account 426.5, Other Deductions.[30]
>
> 18 C.F.R. Part 101, Account 426.5, Other Deductions, states:
>
> This account shall include other miscellaneous expenses which are nonoperating in nature, but which are properly deductible before determining total income before interest charges.

Background

In the process of evaluating Duke Companies' compliance with the hold harmless commitment, audit staff issued data requests and interviewed company employees regarding the accounting and formula rate impact of activities engaged prior to and after public announcement of the merger, such as outside service costs incurred to facilitate the merger and associated internal corporate costs. In reviewing materials received, audit staff found that Duke Energy's corporate development group incurred over $1.5 million in merger transaction costs in the second half of 2010 (i.e., prior to the merger announcement in January 2011) and allocated those costs to its then public utility subsidiaries – DEC, DEI, DEO, and DEK – prior to consummation of the merger.

The costs included $1.35 million paid to outside consultants, lawyers, and accountants for financial forecasting, analysis of market power issues and related services, and $150,000 of internal labor and other costs related to this work. The subsidiary companies improperly recorded the merger transaction outside service costs in Account 923, Outside Services Employed, and most of the associated internal labor and other costs in Account 920, Administrative and General Salaries. Account balances reported in each company's Form No. 1 were included in the determination of the company's wholesale power and transmission formula rate service charges.

DEC, DEI, DEO, and DEK reported these costs in their respective 2010 Form No. 1 reports. The companies neither characterized the costs as merger-related CTA following the merger announcement and issuance of the Merger Order, nor excluded the costs from wholesale power and transmission formula rate determinations in 2011 or subsequent years.

[30] *See Allegheny Energy, Inc.*, 133 FERC ¶ 61,222 at P 73 (2010). See also *Midwest Power Systems, Inc. and Iowa-Illinois Gas and Elec. Co.*, 71 FERC ¶ 61,386, at 62,509 (1995); *MidAmerican Energy Co. and MidAmerican Energy Holdings Co.*, 85 FERC ¶ 61,354, at 62,370 (1998); and *Wis. Elec. Power Co.*, 74 FERC ¶ 61,069, at 61,192 (1996).

Pursuant to the hold harmless commitment, the companies should not have included the $1.5 million in merger transaction costs in wholesale rate determinations without first submitting a section 205 filing to the Commission that demonstrated the costs were offset by quantified savings produced by the merger. Moreover, pursuant to long-standing Commission precedent, the merger transaction costs the companies recorded in Accounts 920 and 923 are considered nonoperating in nature and, as such, were required to be recorded to Account 426.5. The text of Account 426.5 states that the account shall include expenses that are nonoperating in nature. Duke Energy estimated that wholesale power and transmission customers' revenue requirements were inappropriately overstated $745,000.

Recommendations

We recommend Duke Companies:

9. Revise accounting policies and procedures to appropriately account for merger transaction costs consistent with Commission accounting requirements.

10. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the inclusion of merger transaction outside services and related costs in wholesale power and transmission formula rate charges during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

11. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

12. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

4. Use of the Consolidated Method of Accounting

DEC and DEP accounted for investments in subsidiaries on a consolidated basis in their Form No. 1 reports, contrary to the Commission's long-standing accounting policy.

Pertinent Guidance

Order No. 469 revised and amended sections of 18 C.F.R. Parts 101 and 201 to adopt the equity method of accounting for long-term investments in subsidiaries and add new balance sheet and income statement accounts, and definitions. Order No. 469 states in part:

> Under the equity method of accounting, the utility's investment account is increased or decreased to reflect the utility's proportionate share of a subsidiary's current earnings applicable to common stock regardless of whether the earnings are actually paid out as dividends to the utility. When dividends are received, the investment account is reduced by an equivalent amount.[31]

18 C.F.R. Part 101, Account No. 123.1, Investment in Subsidiary Companies, states:

> A. This account shall include the cost of investments in securities issued or assumed by subsidiary companies and investment advances to such companies, including interest accrued thereon when such interest is not subject to current settlement plus the equity in undistributed earnings or losses of such subsidiary companies since acquisition. This account shall be credited with any dividends declared by such subsidiaries.
>
> B. This account shall be maintained in such a manner as to show separately for each subsidiary: the cost of such investments in the securities of the subsidiary at the time of acquisition; the amount of equity in the subsidiary's undistributed net earnings or net losses since acquisition; advances or loans to such subsidiary; and full particulars regarding any such investments that are pledged.

[31] *Revisions in the Uniform System of Accounts, and Annual Report Forms No.1 and No. 2 to Adopt the Equity Method of Accounting for Long-Term Investments in Subsidiaries*, Order No. 469, 49 FPC 326, *reh'g denied*, 49 FPC 1028 (1973).

18 C.F.R. Part 101, Account 216.1, Unappropriated Undistributed Subsidiary Earnings, states:

> This account shall include the balances, either debit or credit, of undistributed retained earnings of subsidiary companies since their acquisition. When dividends are received from subsidiary companies relating to amounts included in this account, this account shall be debited and account 216, Unappropriated Retained Earnings, credited.

18 C.F.R. Part 101, Account No. 418.1, Equity in Earnings of Subsidiary Companies, states:

> This account shall include the utility's equity in the earnings or losses of subsidiary companies for the year.

Background

DEC and DEP formed wholly owned special purpose subsidiaries, Duke Energy Receivables Finance Company, LLC (DERF) and Duke Energy Progress Receivables, LLC (DEPR), respectively, in 2003 and 2013. The companies accounted for their investments in the subsidiaries using the consolidated method of accounting. Specifically, DEC consolidated DERF in its Form No. 1 reports from 2003 through 2013; and DEP consolidated DEPR in its Form No. 1 in 2013. The accounting resulted in the recognition of property, expenses, revenue, debt, and equity of the subsidiaries in DEC and DEP's respective Form No. 1 reports. During the course of the audit, in 2014, the companies ceased accounting for their investments in the subsidiaries using the consolidation method of accounting and began using the equity method of accounting.

Prior to 2014, DEC and DEP's accounting for their investments in the subsidiaries was not consistent with the Commission's accounting requirements, which required the companies to account for the investments using the equity method of accounting. In accordance with the provisions of Order No. 469, the companies were required to account for the subsidiaries as investments in Account 123.1, Investments in Associated Companies, and record equity in earnings of the subsidiaries in Account 418.1, Equity in Earnings of Subsidiary Companies, and undistributed retained earnings of the subsidiaries in Account 216.1, Unappropriated Undistributed Subsidiary Earnings.[32]

[32] *Id*.

On August 19, 2015, during the course of the audit, Duke Energy submitted a request to the Commission on behalf of the companies for retroactive and prospective waivers of the equity method accounting requirement.[33] In the filing, among other things, DEC and DEP acknowledged that they had inappropriately accounted for investments in their subsidiaries using the consolidation method of accounting, and improperly included the results of the subsidiaries' operations in cost of service formula rate determinations. On December 18, 2015, the companies submitted a filing to the Commission under section 205 of the FPA seeking approval of proposed amendments to the formula rates in their Joint OATT and wholesale power agreements to provide for consolidation of the subsidiaries for cost of service rate determination purposes.[34]

Duke Energy did not notify audit staff of the inappropriate consolidation accounting, or of its request for waiver of the equity accounting requirements. The company should have disclosed the erroneous accounting to audit staff when it discovered the matter, which according to its representation occurred in late 2014. However, neither audit staff nor the Commission was notified of the improper accounting and the associated rate impacts until August 2015. Duke Energy's lack of timely disclosure of DEC and DEP's noncompliance with Commission regulations is problematic. The company should take necessary steps to ensure that its corporate compliance culture and program are strengthened to prevent situations like this on a going forward basis.

[33] Duke Energy Carolinas, LLC, et al., Request for Waiver, Docket No. AC15-174-000, (filed Aug. 19, 2015). The filing requested waivers of the equity accounting requirement on behalf of DEC, DEP, and DEF, which formed a wholly owned subsidiary Duke Energy Florida Receivables, LLC (DEFR) in 2014. The Chief Accountant issued a delegated letter order on February 12, 2016 that granted the requested waivers to the companies and directed specific accounting regarding sales of accounts receivable. Duke Companies filed a request for rehearing of the letter order on March 14, 2016.

[34] *Duke Energy Carolinas, LLC, et al.*, Docket Nos. ER16-577-000, ER16-578-000, and ER16-579-000. The Commission issued delegated letter orders on February 11, 2016, accepting for filing the amendments to the Joint OATT and rate schedules to provide for DEC, DEP, and DEF's use of the consolidated method of accounting for ratemaking purposes.

Recommendations

We recommend Duke Companies:

13. Review and, as needed, revise accounting policies, practices, and procedures to ensure that investments in subsidiaries are accounted for consistent with the Commission's equity method accounting requirements.

14. Evaluate the accounting applied to Duke Companies' existing subsidiaries and notify DAA of any areas of noncompliance with Commission accounting requirements.

15. Revise documented policies, procedures and processes to ensure timely notice is provided to relevant regulators regarding instances of noncompliance with regulations, rules, and orders.

16. Provide training to staff on procedures, practices, and available tools to transparently or anonymously report instances of noncompliance to senior management, the Board of Directors, and relevant regulators.

5. Accounting for Sales of Accounts Receivable

DEC, DEP, and DEF misclassified an estimated $94.7 million of nonoperating expenses and receivables arising from transactions with their subsidiaries during the audit period. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $61 million.

Pertinent Guidance

18 C.F.R. Part 101, Account 930.2, Miscellaneous General Expenses, states in part:

> This account shall include the cost of labor and expenses incurred in connection with the general management of the utility not provided for elsewhere.

18 C.F.R. Part 101, Account 426.5, Other Deductions, states in part:

> This account shall include other miscellaneous expenses which are nonoperating in nature, but which are properly deductible before determining total income before interest charges.

The Commission addressed the appropriate accounting for the sale of accounts receivable in Opinion No. 375, which stated in part:

> From an accounting standpoint, we find that the record supports the staff and intervenors' position – which the initial decision adopted – that the loss on the sale of accounts receivable was erroneously recorded by SERI [System Energy Resources, Inc.] in Account 930.2. . ..[35]

Background

During audit fieldwork, audit staff analyzed data regarding transactions between DEC, DEP, and DEF and the companies' respective nonutility subsidiaries, DERF, DEPR, and DEFR, and interviewed employees responsible for accounting for the transactions. The transactions involved the companies' sales of accounts receivable to their subsidiaries. The receivables arose from billings on sales of electricity and related services by the companies. The companies sold the receivables to their subsidiaries at a loss (or discount), and accounted for the loss as an expense by debiting Account 930.2, Miscellaneous General Expenses, an account included in wholesale power and transmission service cost formula rate determinations, for the amount of the loss. DEC,

[35] *System Energy Resources, Inc.*, 60 FERC ¶ 61,131 (1992).

DEP, and DEF recognized total losses of $149.6 million, $35.1 million, and $23.5 million, respectively, from 2011 through 2014.

Audit staff also discovered that there were similar transactions involving sales of accounts receivable by DEI, DEO, and DEK to Cinergy Receivables, a Duke Energy subsidiary. However, through discussions with audit staff, Duke Energy represented that instead of recording losses on sold receivables in Account 930.2, DEI, DEO, and DEK accounted for the losses in Account 904, Uncollectible Accounts, an account not included in wholesale power or transmission service cost formula rate determinations.

DEC, DEP, and DEF performed collection services on behalf of their subsidiaries associated with the sold receivables whereby the companies collected bill payments from customers and remitted funds received to the subsidiaries. The companies charged the subsidiaries a fee for performing the collection service, which effectively resulted in a reimbursement of the collection service cost incurred by the companies. Expenses incurred by the companies associated with performing the collection service were accounted for by debiting the costs to Account 903, Customer Records and Collection Expenses. These expenses were also accounted for as a debit in Account 930.2 that Duke Energy represented was the fee billed to the subsidiaries for performing the collection service. As a result of this accounting, DEC, DEP, and DEF double-counted expenses in their respective Form No. 1 reports associated with collection services performed. Furthermore, the companies accounted for the reimbursements of their incurred collection service expenses that resulted from their billed subsidiaries by crediting Account 421, Miscellaneous Non-Operating Income.

Duke Companies' accounting for the loss on the sale of the receivables was not consistent with the Commission's accounting requirements and precedent. Under the Uniform System of Accounts (USofA), sales of accounts receivable constitute the disposition of utility assets. The USofA contemplates that in transactions of this nature, a company should recognize a gain or loss, measured by the difference between the net book value of the asset at the date of the sale and the proceeds from the sale, less related fees and expenses of the sale. Further, the USofA requires a company to record any gains or losses from the disposition of assets in nonoperating expense accounts, except with respect to the sale of future use property.[36] The instructions to Account 426.5, Other Deductions, provide for the recording of nonoperating expenses of this nature. Additionally, the Commission has previously addressed the matter of the appropriate

[36] With respect to future use property recorded in Account 105, Electric Plant Held for Future Use, the USofA requires a company to include a gain on a sale in Account 411.6, Gains from Disposition of Utility Plant, and a loss in Account 411.7, Losses from Disposition of Utility Plant.

accounting for sales of receivables in its Opinion No. 375, wherein it was determined that the loss on the sale of receivables should be accounted for in Account 426.5.[37]

In addition, DEC, DEP, and DEF's accounting for reimbursements of incurred collection service expenses was not consistent with the Commission's accounting requirements. The USofA contemplates that such reimbursements of collection service expenses incurred by DEC, DEP, and DEF on behalf of their respective subsidiaries be recorded as a reduction of the expenses. Accordingly, the companies should have accounted for the reimbursements through a credit entry to the collection service expenses recorded in Account 903.

Duke Energy represented that prior to 2014, DEC and DEP's accounting for the losses on the sales of receivables and collection service fees billed to the subsidiaries that were recorded in Account 930.2 had no impact on service rates charged to wholesale power and transmission formula rate customers due to accounting entries the companies made associated with consolidation method accounting that offset the items and neutralized the rate impact. Duke Energy indicated that the companies made the offsetting entries from the respective dates their subsidiaries were established and transactions initiated through 2013.[38] However, in 2014, DEC and DEP ceased their practice of using the consolidation method of accounting.[39] Cessation of consolidation method accounting led the companies to end their practice of recording the offsetting entries. Moreover, DEF established its subsidiary, DEFR, in 2014, and did not record any accounting entries to offset its losses on the sales and collection service fees billed to its subsidiary. As a result, rates charged by DEC, DEP, and DEF based on amounts reported in the companies' respective 2014 Form No.1 reports included the nonoperating losses and collection service fees that were misclassified in Account 930.2 and not offset by other entries. This led to DEC, DEP, and DEF inappropriately including the losses and fees of $38.1 million, $33.1 million, and $23.5 million, respectively, in rate determinations.

The companies' accounting mistakes led to an estimated $94.7 million of costs being inappropriately included in wholesale power and transmission formula rate service cost determinations during the audit period. Duke Energy estimated that this resulted in wholesale power and transmission customers' revenue requirements being inappropriately overstated by an estimated $61 million.

[37] *System Energy Resources, Inc*., 60 FERC ¶ 61,131 (1992).

[38] DEC's subsidiary, DERF, was established in 2003, and DEP's subsidiary, DEPR, was established in 2013.

[39] *See* Finding No. 4, Consolidation Method of Accounting.

On March 14, 2016, Duke Companies filed a request for rehearing of the Chief Accountant letter order in Docket No. AC15-174-000 challenging the order's decision regarding the appropriate accounting for losses on the sale of receivables, which is also addressed by this Audit Finding. In light of the current challenge to the Chief Accountant's order and uncertain outcome, as well as, the potential of a contested audit over the identical issue, in this instance the portions of this Audit Finding that relate to the losses issues, including Recommendations 17 and 18, shall be held in abeyance and shall be subject to the outcome of the rehearing request and any subsequent petitions for court review. Although the recommendations regarding the portion of this Audit Finding relating to the losses issues are held in abeyance and subject to the outcome of the rehearing request and any subsequent petitions for court review, the requirement to make refunds in accordance with Recommendation 21 below is not impacted by the rehearing request.

Recommendations

We recommend Duke Companies:

17. Revise procedures to ensure that all costs and account balances associated with the sale of accounts receivable are accounted for in accordance with Commission accounting regulations. Among other things, the corrected accounting should ensure that all losses associated with receivable sales are recorded in Account 426.5.

18. Provide the revised procedures to DAA for review within 60 days of receiving the final audit report.

19. Recalculate charges to wholesale power and transmission customers of DEC, DEP, and DEF and submit the recalculations in a refund analysis to DAA for review within 60 days of receiving the final audit report. The refund analysis should explain and detail the: (1) return of collection service billings charged in 2014; (2) return of losses on the sales included in rates; (3) determinative components of the refund; (4) refund method; (5) period(s) refunds will be made; and (6) interest calculated in accordance with section 35.19 of Commission regulations.

20. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

21. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

6. Accounting for Lobbying Expenses

Duke Companies recorded approximately $2.4 million of lobbying expenses in above-the-line operating accounts from 2011 to 2013. As a consequence, Duke Companies improperly included these costs in wholesale power and transmission formula rate service cost determinations.

Pertinent Guidance

18 C.F.R. Part 101, Account 426.4, Expenditures for Certain Civic, Political, and Related Activities, states in part:

> This account shall include expenditures for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances . . . or approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials. . . .

Background

Audit staff evaluated costs incurred by Duke Companies associated with civic, political, and related activities during the audit period. Audit staff reviewed third-party lobbying expenditure disclosures, press articles, internal lobbyist meeting schedules and agendas, and interviewed internal lobbyists and support staff to understand the nature and extent of the companies' lobbying activities. In addition, audit staff tested a sample of work orders, invoices, and associated accounting detail records that support internal lobbyists' labor costs incurred. Audit staff discovered that Duke Companies improperly recorded nearly $2.4 million in lobbying costs to above-the-line operating accounts rather than to Account 426.4, Expenditures for Certain Civic, Political, and Related Activities, as required.

Account 426.4 provides for reporting expenditures for the purpose of influencing public opinion, such as lobbying expenses. Audit staff found that Duke Companies recorded a portion of these costs associated with wages and salaries of internal lobbyist and support staff in Account 426.4 as required, but failed to properly charge other related costs to the account associated with the labor, such as payroll taxes, retirement, health, and other benefits. Audit staff also found that the companies incorrectly accounted for amounts paid to outside firms that lobby on behalf of the companies. Duke Companies improperly included these expenses in wholesale power and transmission formula rate determinations and recovered a portion of the costs through charges to customers.

Further, audit staff found that Duke Companies lacked formal procedures and oversight controls to help ensure that lobbying costs were accounted for appropriately.

The companies should implement procedures to reduce the risk that lobbying costs are inappropriately accounted for and included in jurisdictional rate determinations.

Recommendations

We recommend Duke Companies:

22. Establish and implement written procedures governing the methods used to account for, track, report, and review lobbying costs incurred.

23. Provide training on Commission accounting requirements and the impact of accounting on cost-of-service rate determinations to employees involved in lobbying and lobbying-related work, and those with oversight responsibility for lobbying cost allocations. Also, develop a training program that supports the provision of periodic training in this area.

24. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the improper inclusion of lobbying costs in operating accounts during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

25. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

26. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

7. Allocation of Lobbyist Labor Costs

Duke Companies accounted for the labor costs of internal lobbyists and their support staff in operating accounts that lacked support for inclusion in the accounts. Improper accounting for the costs can lead to inappropriate recovery of the costs through rates charged and billed to customers.

Pertinent Guidance

18 C.F.R. Part 101, General Instruction No. 9, Distribution of Pay and Expenses of Employees, states:

> The charges to electric plant, operating expense and other accounts for services and expenses of employees engaged in activities chargeable to various accounts, such as construction, maintenance, and operations, shall be based upon the actual time engaged in the respective classes of work, or in case that method is impracticable, upon the basis of a study of the time actually engaged during a representative period.

18 C.F.R. Part 101, General Instruction No. 10, Payroll Distribution, states:

> Underlying accounting data shall be maintained so that the distribution of the cost of labor charged direct to the various accounts will be readily available. Such underlying data shall permit a reasonably accurate distribution to be made of the cost of labor charged initially to clearing accounts so that the total labor cost may be classified among construction, cost of removal, electric operating functions (steam generation, nuclear generation, hydraulic generation, transmission, distribution, etc.) and nonutility operations.

18 C.F.R. Part 101, Account 426.4, Expenditures for Certain Civic, Political, and Related Activities, states in part:

> This account shall include expenditures for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances . . . or approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials . . . .

Background

In connection with the evaluation of Duke Companies' expenditures for lobbying activities, audit staff discovered that the companies' allocation of the labor costs of internal lobbyists and their support staff was based in part on the amount of time that state legislatures and Congress were in session. Duke Energy explained that these entities were in session on average 180 days a year, and that lobbying activities of its staff to influence legislation would typically be performed while the legislatures and Congress were in session. This resulted in the companies using a default allocator that charged 50 percent of lobbying costs above-the-line to operating accounts and 50 percent below-the-line to Account 426.4, Expenditures for Certain Civic, Political, and Related Activities.

Audit staff interviewed internal lobbyists and their support staff to understand their roles and job assignments, and reviewed lobbyists' schedules as documented in email, itineraries from industry conferences, and other materials. Duke Energy represented that the companies' internal lobbyist performed internal corporate functions such as (1) budgeting, (2) performance appraisals, (3) training, and (4) other activities. However, audit staff could not determine based on documentation provided, that the 50/50 labor allocation split between above- and below-the-line accounting for lobbying and related costs was accurate or reasonable. Moreover, audit staff discovered that the companies neither had a formal oversight review process to assess the accuracy of the labor allocations nor maintained documentation to support the allocations.

General Instructions No. 9, Distribution of Pay and Expenses of Employees, and No. 10, Payroll Distribution, require public utilities to charge lobbying-related labor to operations based on actual time engaged in utility operations or on a representative time study, and to maintain data supporting distribution of the labor to operating costs. Audit staff found that Duke Companies' charges of lobbying and support staff labor to operations were neither based on actual time engaged in utility operations nor derived from representative time studies, as required. The companies also did not maintain data supporting distribution of the costs to utility operations. Duke Companies' accounting for lobbying labor time charges was not consistent with Commission accounting requirements and could have resulted in the inclusion of inappropriate costs in operating accounts, and consequently, in charges to transmission service formula rate and wholesale requirements customers. This could have led to the overcharging of wholesale ratepayers.

Recommendations

We recommend Duke Companies:

27. Revise written policies and procedures to create a process to document and verify appropriate allocation of lobbying and lobbying-related costs, and maintain auditable support for the cost included in rate determinations.

28. Retain an independent third-party entity to conduct a representative labor time study to determine an appropriate allocation of internal lobbyist labor, support

staff, and associated costs that should be accounted for in operating and nonoperating accounts based on time spent by employees engaged in the activities. Provide the study results to audit staff within 180 days of receiving the final audit report.

29. Include the results of the labor time study in the determination of lobbying-related labor cost allocations as of January 1, 2016.

30. Implement policies and procedures to perform a labor time study at least biennially using an independent third-party or internal company resources that are able to attest to the results of the study. Revise the lobbying-related labor cost allocations based on the results of the study.

8. Nonutility Expenses in Operating Accounts

Duke Companies recorded approximately $490,000 of nonutility expenses in operating accounts in 2014. As a result, inappropriate costs were included in wholesale power and transmission formula rate service cost determinations and charged to customers.

Pertinent Guidance

Accounting Release 12, Discriminatory Employment Practices, states in part:

> Expenditures resulting from employment practices found to be discriminatory by a judicial or administrative decree or that were the result of a compromise settlement or consent decree are not just and reasonable cost of utility operations and as such must be charged to nonoperating expense accounts.

18 C.F.R Part 101, Account 426.1, Donations, states:

> This account shall include payments or donations for charitable, social, or community welfare purposes.

18 C.F.R. Part 101, Account 426.5, Other Deductions, states:

> This account shall include other miscellaneous expenses for which are non-operating in nature, but which are properly deductible before determining total income before interest charges.

Background

Audit staff reviewed a sample of expenses charged to administrative and general (A&G) accounts to determine whether the charges were accounted for in accordance with Commission accounting requirements. The sample included charges to Accounts 920, Administrative and General Salaries, 923, Outside Services Employed, and 926, Employee Pensions and Benefits, in 2012. Audit staff reviewed accounting records and documentation supporting amounts reported in the accounts, such as invoices, work orders, and billings. Audit staff also interviewed Duke Companies' employees with responsibility for documenting and accounting for costs reported in the accounts.

Audit staff's review found that Duke Companies accounted for $100,000 of expenditures resulting from employment practices found to be discriminatory as operating expenses. However, in accordance with the requirements of Accounting Release 12, Discriminatory Employment Practices, expenses of this nature should be accounted for as nonoperating expenses. Of the $100,000, audit staff found that $40,000 was improperly recorded to Account 923 and inappropriately included in transmission formula rate determinations. The remaining $60,000 was incorrectly accounted for in production and distribution operating accounts, including Accounts 519, Coolants and Water, 524, Miscellaneous Nuclear Power Expenses, and 583, Overhead Line Expenses. The costs should have been charged to Account 426.5, Other Deductions, consistent with the instructions of the account. Account 426.5 provides for recording expenses that are nonoperating in nature, and are properly deductible before determining total income before interest charges.

Further, audit staff also found that Duke Companies improperly charged about $39,000 in costs related to donations and charitable contributions to above-the-line operating accounts rather than Account 426.1, Donations, as required. Account 426.1 provides for reporting payments or donations for charitable, social, or community welfare purposes. The sampled invoices that audit staff reviewed included expenditures for charity-related activities that were improperly charged to operating accounts.

Because audit staff's review involved a select, small sample of transactions out of a larger population of transactions that involved expenses charged to Accounts 920, 923, and 926, audit staff believes that review of a larger number of transactions charged to these accounts may have revealed additional accounting errors that could have resulted in inappropriate charges to wholesale power and transmission formula rate customers. Duke Companies represented that they performed an analysis of all charges to the 900 series expense accounts for April 2014 through December 2014, and estimated that they incorrectly accounted for approximately $490,000 of costs in the accounts in 2014. These errors are the result of Duke Companies' lack of documented policies and insufficient training of employees on Commission requirements pertaining to accounting for nonoperating expenses. Employees with responsibility for recording expenses of this nature should have knowledge of the importance of appropriate accounting and the impact of improper accounting on rates charged through transmission formula rates.

Recommendations

We recommend Duke Companies:

31. Develop and implement written policies, procedures, and controls to ensure proper accounting and reporting of nonutility expenses.

32. Provide training for employees involved in the invoicing process on Commission accounting requirements and the impact of the accounting on cost-of-service rate determinations.

33. Within 60 days of receiving the final audit report, provide documentation supporting the analysis performed of invoiced expenses recorded to A&G accounts in 2014 that identified misclassified nonutility expenses included in A&G accounts. Develop an estimate of misclassified nonutility expenses accounted for in operating accounts in 2011 through 2013 and 2015.

34. Implement policies and procedures to provide periodic audits or reviews of A&G transactions by external or internal auditors.

35. Submit a refund analysis, within 60 days of receiving the final audit report, for review to DAA that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the improper inclusion of identified and estimated nonutility expenses in charges to wholesale power and transmission customers during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made. Include the results of the invoice analysis in the refund analysis.

36. File a refund report with the Commission after receiving DAA’s assessment of the refund analysis.

37. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Appendix: Duke Energy’s Comments on Audit Report

DUKE ENERGY.

Brian D. Savoy
Senior Vice President, Chief Accounting
Officer and Controller

Duke Energy Corporation
550 South Tryon Street / DEC44A
Charlotte, NC 28202

704 382 6242

brian.savoy2@duke-energy.com

March 30, 2016

Mr. Bryan K. Craig
Director and Chief Accountant
Division of Audits and Accounting
Office of Enforcement
Federal Energy Regulatory Commission
888 First Street NE, Room 5K-13
Washington, DC 20426

RE: Office of Enforcement
Docket No. PA14-2-000
Duke Energy Corporation

Dear Mr. Craig:

On February 19, 2016, the Division of Audits and Accounting ("DAA") within the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") issued a draft audit report setting forth the DAA's findings and recommendations resulting from the audit of Duke Energy Corporation ("Duke Energy") and its public utility subsidiaries' compliance with (1) conditions in Commission merger authorization orders, (2) transmission formula rate tariff requirements, and (3) accounting and financial reporting regulations. After several constructive discussions between DAA staff and Duke Energy, the draft audit report was revised several times. DAA staff sent the latest revision to Duke Energy dated March 29, 2016. Duke Energy is responding to the March 29 revision.

SUMMARY

In the draft audit report as revised, the DAA made eight findings and 37 associated recommendations. In sum, Duke Energy accepts five of the eight findings and all associated recommendations. Duke Energy respectfully disagrees with, but will not contest, two of the eight findings (findings 2 and 3) and agrees to comply with all associated recommendations. Duke Energy disagrees with a portion of, but will not contest under 18 CFR Part 41, one of the eight findings (finding 5) and all recommendations as they apply to the portion with which it disagrees, and accepts in part finding 5 and all recommendations as they apply to the accepted portion.

RESPONSE TO FINDINGS

In accordance with the procedures set forth in 18 C.F.R. 41.1, Duke Energy responds to each of the findings as follows:

- **Finding 1.** *Accounting for Merger Transaction Costs* – Duke Companies did not file merger transaction accounting entries with the Commission as required by the Merger Order, and the companies recorded merger transaction costs in operating accounts, contrary to the Commission's long-standing policy that such costs be recorded in nonoperating accounts. By not filing the accounting entries, Duke Companies prevented Commission review of the merger accounting and correction of any entries that were not in accordance with Commission accounting requirements.

Response: Duke Energy accepts this finding.

- **Finding 2.** *Merger Transaction Internal Labor Costs* – Duke Companies improperly included approximately $31.4 million of merger transaction internal labor costs in wholesale power and transmission formula rate service cost determinations without first submitting a section 205 filing demonstrating that the costs were offset by quantified savings produced by the merger. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated an estimated $17.5 million.

Response: Duke Energy respectfully disagrees with this finding, but will not contest it. For the purpose of establishing a complete record, Duke Energy explains its position as follows.

Duke Energy acknowledges its obligation to hold transmission and wholesale power customers harmless for five years from costs related to the merger of Duke Energy and Progress Energy, Inc. (the "Merger").

Between the time of the Commission's Merger Order issued on September 30, 2011 and the closing of the Merger on July 2, 2012, Duke Energy determined that its hold harmless commitment is intended to apply to costs caused by the Merger ("Incremental Costs") and not to costs that would have been incurred even in the absence of the Merger ("Non-Incremental Costs"). No Commission orders squarely addressed this issue, and it seemed to be inherent in the nature of a *hold harmless* commitment that it would protect customers only from costs that they would not have incurred otherwise.

On the basis of this logic, Duke Energy did not treat as transaction-related costs any portion of the regular compensation that employees would have received in the absence of the Merger even if the employees spent some of their time working on transaction-related activities. The company would have paid those same salaries to the employees with or without the Merger. Thus the regular compensation of employees was viewed as Non-Incremental Costs. On the other hand, Duke Energy did treat as transaction-related costs any compensation paid to employees that would *not* have been incurred but for the Merger. For example, this included any bonuses paid to employees in recognition of the extended hours many employees worked to fulfill their regular duties and to work on merger activities. It also included temporary employees and contractors hired to backfill for work that could not be absorbed in this manner. These costs were viewed as Incremental Costs and accordingly were excluded from FERC-jurisdictional rates.

Treatment of internal labor costs in the context of a hold harmless obligation was certainly not a settled issue in early 2012 or even today. This uncertainty was reflected in the Commission's notice of proposed *Policy Statement on Hold Harmless Commitments* issued January 22, 2015 in Docket No. PL15-3. In this notice of proposed policy statement issued two and a half years after the closing of the Merger, the Commission states as follows:

> "...we propose to clarify those costs to which hold harmless commitments will apply. Although the Commission has provided broad guidance regarding the costs that should be covered under hold harmless commitments, it has never defined those costs with much specificity, leading to inconsistency with respect to this issue."[1]

The Commission proposed to clarify that internal labor costs should be treated as transaction-related costs and stated as follows:

> "If the duties of employees are not solely dedicated to activities related to a transaction, internal labor costs deemed merger-related should be determined in a manner that is proportionally equal to the amount of time spent on the merger compared to other activities of the utility and tracked accordingly."[2]

While this *proposal* is clear on this issue, it is worth repeating that it was issued two and a half years after the Merger closed. It is also important to note that it is just a proposal at this time because the final policy statement has not been issued. In addition, some commenters specifically disagreed with this point.[3] Finally, the Commission stated in the notice of proposed policy statement that it would have prospective effect only.[4]

Notwithstanding Duke Energy's belief that its failure to exclude from rates Non-Incremental internal labor costs was not a violation of any settled policy and in fact was based on the most reasonable interpretation of its hold harmless commitment, Duke Energy will not expend the resources necessary to contest this issue and will comply with all associated recommendations in the audit report. Duke Energy reserves all rights in the event that the Commission issues an order

[1] Paragraph 16 of the notice of proposed policy statement.
[2] Footnote 41 of the notice of proposed policy statement.
[3] See the comments of Edison Electric Institute filed on March 30, 2015 at p. 15-16.
[4] Paragraph 20 of the notice of proposed policy statement.

in the proposed policy statement proceeding or any other proceeding that is not consistent with Finding 2.
Duke Energy estimates that the total refunds that will be due to transmission and wholesale power customers arising from this finding will be approximately $1.2 million plus interest.

- **Finding 3**. *Merger Transaction Outside Services and Related Costs* – Duke Companies incorrectly included $1.5 million of merger transaction outside services and related costs in wholesale power and transmission formula rate service cost determinations without first submitting a section 205 filing demonstrating the costs were offset by quantified savings produced by the merger. In addition, the companies recorded the merger transaction costs in operating accounts, contrary to the Commission's long-standing policy that such costs be recorded in nonoperating accounts. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated an estimated $745,000.

Response: Duke Energy respectfully disagrees with this finding, but will not contest it. For the purpose of establishing a complete record, Duke Energy explains its position as follows.

The costs which are the subject of this finding are costs incurred in 2010 to investigate, agree to, and perform preliminary due diligence regarding, the Merger prior to the announcement of the Merger. Duke Energy made the determination that its hold harmless commitment was not intended to include such costs incurred during the formative stage of a potential transaction before it was clear that the company would even pursue the transaction. Like most utility holding companies, Duke Energy has a corporate development group that regularly investigates and reviews potential transactions as part of its routine operations. Only a very small percentage of potential transactions reviewed are ever consummated. In order to comply with a hold harmless commitment as interpreted in this Finding 3 for a transaction that is eventually consummated, the company would have to track all its costs for each and every potential transaction it reviews even though the vast majority will never be consummated. This would be unwieldy and wasteful. Because these potential transactions often will benefit customers, discouraging investigation of them is not in the best interests of customers.

Treatment of such investigation costs incurred prior to the announcement of a transaction in the context of a hold harmless obligation was certainly not a settled issue in early 2012 or even today. This uncertainty was reflected in the Commission's notice of proposed *Policy Statement on Hold Harmless Commitments* discussed in Duke Energy's response to Finding 2 above.

In the notice of proposed policy statement, the Commission proposed to clarify that such investigation costs would be subject to the hold harmless commitment.[5]

[5] Paragraph 22 of the notice of proposed policy statement.

As in Duke Energy's response to Finding 2 above, we will point out again that the notice of proposed policy statement was issued two and a half years after the Merger closed, and is just a proposal at this time because the final policy statement has not been issued. In addition, some commenters specifically disagreed with this point.[6]

Notwithstanding Duke Energy's belief that its failure to exclude pre-announcement costs that are the subject of Finding 3 was not a violation of any settled policy, Duke Energy will not expend the resources necessary to contest this issue and will comply with all associated recommendations in the audit report.

Duke Energy estimates that the total refunds that will be due to transmission and wholesale power customers arising from this finding will be approximately $60,000 plus interest.

- **Finding 4.** *Use of the Consolidation Method of Accounting* – DEC and DEP accounted for investments in subsidiaries on a consolidated basis in their FERC Form No. 1, Annual Reports (Form No. 1), contrary to the Commission's long-standing accounting policy.

Response: Duke Energy accepts this finding.

- **Finding 5.** *Accounting for Sales of Accounts Receivable* – DEC, DEP, and DEF misclassified an estimated $94.7 million of nonoperating expenses and receivables arising from transactions with their subsidiaries during the audit period. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $61 million.

Response: Duke Energy disagrees with the portion of this finding that concerns accounting for losses on the sale of receivables. However, Duke Energy will not contest this finding under 18 CFR Part 41 because the portion of this finding that relates to accounting for losses on the sale of receivables, including recommendations 17 and 18, will be held in abeyance and will be subject to the outcome of Duke Energy's request for rehearing in Docket No. AC15-174-001 pursuant to the draft audit report.

- **Finding 6.** *Accounting for Lobbying Expenses:* Duke Companies recorded approximately $2.4 million of lobbying expenses in above-the-line operating accounts from 2011 through 2013. As a consequence, Duke Companies improperly included these costs in wholesale power and transmission formula rate service cost determinations.

Response: Duke Energy accepts this finding.

[6] See the comments of Edison Electric Institute filed March 30, 2015 at p. 14-15.

- **Finding 7.** *Allocation of Lobbyist Labor Costs:* Duke Companies accounted for the labor costs of internal lobbyists and their support staff in operating accounts that lacked support for inclusion in the accounts. Improper accounting for the costs can lead to inappropriate recovery of the costs through rates charged and billed to customers.

Response: Duke Energy accepts this finding.

- **Finding 8.** *Nonutility Expenses in Operating Accounts:* Duke Companies recorded approximately $490,000 of nonutility expenses in operating accounts in 2014. As a result, inappropriate costs were included in wholesale power and transmission formula rate service cost determinations and charged to customers.

Response: Duke Energy accepts this finding.

RESPONSE TO RECOMMENDATIONS

Duke Energy will comply with all recommendations except as otherwise stated below. As requested, Duke Energy proposes target completion dates below for each recommendation wherever the recommendation does not specify the completion date.

Accounting for Merger Transaction Costs

1. Revise accounting policies and procedures to appropriately account for merger transactions consistent with Commission accounting requirements.

Target Completion Date: September 30, 2016

2. Develop written policies and procedures to timely identify proposed accounting transactions that would trigger a notification to the Commission.

Target Completion Date: September 30, 2016

3. Develop written policies and procedures to submit accounting questions of doubtful interpretation to the Commission.

Target Completion Date: September 30, 2016

4. Provide training to employees on compliance with the merger cost accounting conditions and the revised policies, procedures, and controls for complying with the conditions. Also, develop a training program that supports the provision of periodic training in this area.

Target Completion Date: December 31, 2016

Merger Transaction Internal Labor Costs

If the Commission issues a policy statement on hold harmless commitments and such policy statement is inconsistent with Finding 2 or Finding 3, then Duke Energy reserves the right to seek relief from compliance with any of recommendations 5 – 12 as appropriate.

5. Revise all policies and procedures for tracking, accounting, and excluding merger transaction costs from wholesale power and transmission formula rates, including amounts previously charged to utility plant, accumulated deferred income taxes, construction work in progress with the associated capitalized cost of funds used during construction (AFUDC), and maintenance and operating expense accounts, and future charges to such accounts for any transaction to which a FERC hold harmless obligation applies. The revised procedures should hold customers harmless from all merger transaction costs consistent with requirements of the Merger Order. Among other things, the revised policies and procedures should include an annual review of each subsidiary's merger transaction cost adjustments as well as periodic evaluations within the year, as needed and appropriate.

Target Completion Date: September 30, 2016

6. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the inclusion of merger transaction internal labor and related costs in wholesale power and transmission formula rates during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

7. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

8. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

Merger Transaction Outside Services and Related Costs

9. Revise accounting policies and procedures to appropriately account for merger transaction costs consistent with Commission accounting requirements.

Target Completion Date: September 30, 2016

10. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the inclusion of merger transaction outside services and related costs in wholesale power and transmission formula rate charges during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

11. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

12. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

Use of the Consolidation Method of Accounting

13. Review and, as needed, revise accounting policies, practices, and procedures to ensure that investments in subsidiaries are accounted for consistent with the Commission's equity method accounting requirements.

Response and Target Completion Date: Duke Energy will comply with this recommendation, but notes that the Commission has granted to DEC, DEP, and DEF a waiver from the requirement to use the equity method as discussed above. Target Completion date is 60 days after receiving the final audit report.

14. Evaluate the accounting applied to Duke Companies' existing subsidiaries and notify DAA of any areas of noncompliance with Commission accounting requirements.

Target Completion Date: 60 days after receiving the final audit report.

15. Revise documented policies, procedures and processes to ensure timely notice is provided to relevant regulators regarding instances of noncompliance with regulations, rules, and orders.

Target Completion Date: September 30, 2016

16. Provide training to staff on procedures, practices, and available tools to transparently or anonymously report instances of noncompliance to senior management, the Board of Directors, and relevant regulators.

Target Completion Date: December 31, 2016

Accounting for Sales of Accounts Receivable

17. Revise procedures to ensure that all costs, revenues, and account balances associated with the sale of accounts receivable are accounted for in accordance with Commission accounting regulations. Among other things, the corrected accounting should ensure that all discounts, fees, and revenues associated with receivable sales are recorded in Account 426.5, and that the cost of performing collection services on behalf of the subsidiaries, including employee labor, expenses, and an appropriate allocation of overhead and utility plant, are recorded in Account 426.5.

Response and Target Completion Date: In accordance with the draft audit report, the portions of this recommendation that relate to accounting for losses on the sale of receivables are held in abeyance and subject to the outcome of the rehearing request and any subsequent petitions for review proceedings. The target completion date for portions that do *not* relate to accounting for losses on the sale of receivables is 60 days after receiving the final audit report.

18. Provide the revised procedures to DAA for review within 60 days of receiving the final audit report.

Response and Target Completion Date: In accordance with the audit report, the portions of this recommendation that relate to accounting for losses on the sale of receivables are held in abeyance and subject to the outcome of the rehearing request and any subsequent petitions for review proceedings.

19. Recalculate charges to wholesale power and transmission customers of DEC, DEP, and DEF and submit the recalculations in a refund analysis to DAA for review within 60 days of receiving the final audit report. The refund analysis should explain and detail the: (1) return of collection service billings charged in 2014; (2) return of losses on the sales included in rates; (3) determinative components of the refund; (4) refund method; (5) period(s) refunds will be made; and (6) interest calculated in accordance with section 35.19 of Commission regulations.

20. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

21. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

Accounting for Lobbying Expenses

22. Establish and implement written procedures governing the methods used to account for, track, report, and review lobbying costs incurred.

Response: Duke Energy has completed this action. Duke Energy will update its procedures upon completion of the labor time study referenced in recommendation 28.

23. Provide training on Commission accounting requirements and the impact of accounting on cost-of-service rate determinations to employees involved in lobbying and lobbying-related work, and those with oversight responsibility for lobbying cost allocations. Also, develop a training program that supports the provision of periodic training in this area.

Response: Duke Energy has completed this action. Duke Energy will update its procedures upon completion of the labor time study referenced in recommendation 28.

24. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the improper inclusion of lobbying cost in operating accounts during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

25. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

26. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

Allocation of Lobbyist Labor Costs

27. Revise written policies and procedures to create a process to document and verify appropriate allocation of lobbying and lobbying-related costs, and maintain auditable support for the cost included in rate determinations.

Response: Duke Energy has completed this action. Duke Energy will update its procedures upon completion of the labor time study referenced in recommendation 28.

28. Retain an independent third-party entity to conduct a representative labor time study to determine an appropriate allocation of internal lobbyist labor, support staff, and associated costs that should be accounted for in operating and nonoperating accounts based on time spent by employees engaged in the activities. Provide the study results to audit staff within 180 days of the date of the final audit report.
29. Include the results of the labor time study in the determination of lobbying-related labor cost allocations as of January 1, 2016.

Target Completion Date: 180 days after the date of the final audit report

30. Implement policies and procedures to perform a labor time study biennially using an independent third-party or internal company resources that are able to attest to the results of the study. Revise the lobbying-related labor cost allocations based on the results of the study.

Target Completion Date: 180 days after the date of the final audit report

Nonutility Expenses in Operating Accounts

31. Develop and implement written policies, procedures, and controls to ensure proper accounting and reporting of nonutility expenses.

Response: Duke Energy has completed this action.

32. Provide training for employees involved in the invoicing process on Commission accounting requirements and the impact of the accounting on cost-of-service rate determinations.

Response: Duke Energy has completed this action.

33. Within 60 days of receiving the final audit report, provide documentation supporting the analysis performed of invoiced expenses recorded to administrative and general (A&G) accounts in 2014 that identified misclassified nonutility expenses included in A&G accounts. Develop an estimate of misclassified nonutility expenses accounted for in operating accounts in 2011 through 2013 and 2015.

34. Implement policies and procedures to provide periodic audits or reviews of A&G transactions by external or internal auditors.

Target Completion Date: 60 days after the date of the final audit report

35. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the improper inclusion of identified and estimated nonutility expenses in charges to wholesale power and transmission customers during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made. Include the results of the invoice analysis in the refund analysis.

36. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

37. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

Duke Energy acknowledges and appreciates the professionalism and the courtesy with which DAA staff conducted this audit.

Sincerely,

Brian D Savoy by Paul King

Brian D. Savoy
Senior Vice President, Chief Accounting
Officer and Controller

DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(j)

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807 KAR 5:001, SECTION 16(7)(j)

Description of Filing Requirement:

Prospectuses of the most recent stock or bond offerings.

Response:

See attached.

Witness Responsible:

Christopher R. Bauer

Not New Issue—Book-Entry-Only **Ratings: See "RATINGS" herein**

The opinion of Frost Brown Todd LLC, Bond Counsel ("Original Bond Counsel"), delivered in connection with the original issuance of the Bonds (defined below), stated that under existing federal statutes, decisions, regulations and rulings, the interest on the Bonds is excludable from gross income of the owners for federal income tax purposes (except for interest on any Bond for any period during which such Bond is held by a person who is a "substantial user" of the Project or a "related person"). Such exclusion is conditioned on continuing compliance with the Tax Covenants (hereinafter defined). Interest on the Bonds is not a specific preference item for purposes of the federal alternative minimum tax imposed on individuals and corporations, but such interest is included in adjusted current earnings in calculating the federal alternative minimum tax imposed on certain corporations. In the opinion of Frost Brown Todd LLC, under existing statutes, decisions, regulations and rulings, the interest on the Bonds is exempt from income taxation in the Commonwealth of Kentucky. The text of such Original Bond Counsel opinion is included in Appendix D to this Reoffering Circular. Such opinion spoke only as of the date of initial issuance and delivery of the Bonds and will not be reissued in connection with this reoffering. See "TAX MATTERS" herein. In connection with the conversion of the Bonds to the Term Rate described herein, Taft Stettinius & Hollister LLP will deliver an opinion with respect to each series of bonds pursuant to the Indenture (as defined below) that such conversion will not adversely affect the excludability from gross income of the interest on the Bonds for federal income tax purposes.

$50,000,000
COUNTY OF BOONE, KENTUCKY
Pollution Control Revenue Refunding Bonds
Series 2008A
(Duke Energy Kentucky, Inc. Project) (Non-AMT)

Dated: Date of Issuance **Due: As shown below**

The above-captioned bonds (the "*Bonds*") are special and limited obligations of the County of Boone, Kentucky (the "*Issuer*") and will be payable solely from and secured exclusively by payments, revenues and other amounts pledged thereto pursuant to the Indenture (described herein). The Bonds do not represent or constitute a debt, a liability or a general or moral obligation of the Issuer or the Commonwealth of Kentucky (the "*State*") or any political subdivision thereof within the meaning of the provisions of the constitution or statutes of the State or a pledge of the faith and credit of the Issuer or the State or any political subdivision thereof; and the Bonds do not grant to the owners or holders thereof any right to have the Issuer or the State or any political subdivision thereof levy any taxes or appropriate funds for the payment of the principal or purchase price thereof or premium, if any, or interest thereon. The Issuer has no taxing power. See "THE ISSUER" herein. The proceeds of the Bonds were used to refund bonds previously issued by the Issuer as described herein.

Duke Energy Kentucky, Inc.

The Bonds will bear interest at the Term Interest Rate set forth below for a Term Rate Period until the maturity date set forth below and as described under "THE BONDS – General" herein. The Bonds were originally issued and will mature on the maturity date set forth below. Except as otherwise described herein, interest on the Bonds will be payable semiannually on the dates set forth below.

Series	Interest Rate	Interest Payment Dates	First Interest Payment Date	Original Issuance Date	Maturity Date	CUSIP†
Series 2008A	3.70%	December 1 and June 1	December 1, 2022	December 11, 2008	August 1, 2027	098792AQ7

The Bonds are subject to optional redemption, extraordinary optional redemption and special mandatory redemption, all as described herein.

Price: 100%

The Bonds are fully registered bonds and registered in the name of Cede & Co., as nominee for The Depository Trust Company, New York, New York ("*DTC*"). DTC acts as a securities depository for the Bonds. Purchases of beneficial interests in the Bonds initially will be made in book-entry-only form (without certificates) in denominations of $5,000 and any integral multiple thereof and under certain circumstances are exchangeable as more fully described herein. Principal of the Bonds will be payable upon presentation and surrender of the Bonds at the corporate trust office of the Registrar. So long as DTC or its nominee, Cede & Co., is the registered owner of the Bonds, payments of the principal of, and interest on the Bonds will be made directly to Cede & Co. See "THE BONDS – Book-Entry-Only System" herein.

PNC Capital Markets LLC **Truist Securities, Inc.**

as Remarketing Agents

Dated: June 22, 2022

† CUSIP is a registered trademark of American Bankers Association. The CUSIP number in this Reoffering Circular is provided by CUSIP Global Services LLC, managed on behalf of the American Bankers Association by S&P Capital IQ, a part of McGraw-Hill Financial, Inc. The CUSIP number listed is being provided solely for the convenience of the bondholders and none of the Issuer, the Company, the Trustee or the Remarketing Agents makes any representation with respect to such number or undertakes any responsibility for its accuracy now or at any time in the future.

No person has been authorized to give any information or to make any representations other than those contained in this Reoffering Circular in connection with the offer made hereby and, if given or made, such information or representations must not be relied upon as having been authorized by the Issuer, the Company, or the Remarketing Agents (all as hereinafter defined). Neither the delivery of this Reoffering Circular nor any sale hereunder will, under any circumstances, create any implication that there has been no change in the affairs of the Issuer or the Company since the date hereof. The Remarketing Agents have reviewed the information in this Reoffering Circular in accordance with, and as part of, their responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but do not guarantee the accuracy or completeness of such information. This Reoffering Circular does not constitute an offer or solicitation in any jurisdiction in which such offer or solicitation is not authorized, or in which the person making such offer or solicitation is not qualified to do so or to any person to whom it is unlawful to make such offer or solicitation.

CERTAIN PERSONS PARTICIPATING IN THIS OFFERING MAY ENGAGE IN TRANSACTIONS WHICH STABILIZE, MAINTAIN OR OTHERWISE AFFECT THE PRICE OF THE BONDS. SUCH STABILIZING, IF COMMENCED, MAY BE DISCONTINUED AT ANY TIME.

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REOFFERING CIRCULAR

$50,000,000
County of Boone, Kentucky
Pollution Control Revenue Refunding Bonds
Series 2008A
(Duke Energy Kentucky, Inc. Project) (Non-AMT)

INTRODUCTORY STATEMENT

This Reoffering Circular, including the cover page and Appendices, sets forth information concerning the reoffering of $50,000,000 aggregate principal amount of County of Boone, Kentucky Pollution Control Revenue Refunding Bonds, Series 2008A (Duke Energy Kentucky, Inc. Project) (the "*Bonds*"). The Bonds were originally issued on December 11, 2008.

The Bonds were originally issued by the County of Boone, Kentucky, a de jure county and political subdivision of the Commonwealth of Kentucky (the *"Issuer"*) to refund the Issuer's Pollution Control Revenue Refunding Bonds, Series 2006A (Duke Energy Kentucky, Inc. Project) (the "*Prior Bonds*") which were issued to assist Duke Energy Kentucky, Inc., a public utility and corporation organized and existing under the laws of the Commonwealth of Kentucky (the "*Company*") in refinancing certain air and water pollution control facilities and solid waste disposal facilities (the "*Project Facilities*" or the "*Project*") located within the corporate boundaries of the Issuer at the East Bend Generating Station (the "*Generating Station*"). The proceeds of the Bonds were loaned by the Issuer to the Company, pursuant to a Loan Agreement dated as of December 1, 2008 (together, the *"Loan Agreement"*), between the Company and the Issuer. **The Bonds are currently owned by the Company.** See "APPLICATION OF PROCEEDS." The Company agreed in the Loan Agreement to make payments sufficient to pay when due the principal of and interest and any premium on the Bonds and any other amounts relating thereto. See "THE LOAN AGREEMENT."

The Bonds were issued under a Trust Indenture, dated as of December 1, 2008, as amended and supplemented by that certain First Supplemental Trust Indenture dated as of December 1, 2011 and as further amended and supplemented by that certain Second Supplemental Trust Indenture dated as of November 4, 2016 (together, the *"Indenture"*), between the Issuer and Deutsche Bank National Trust Company, as trustee (the "*Trustee*"). The Registrar and Paying Agent is Deutsche Bank National Trust Company, located in Chicago, Illinois. Terms used as defined terms and not otherwise defined herein are used as defined in the Indenture. See "THE INDENTURE."

The Company's obligations under the Loan Agreement are unsecured. There is no requirement in the Indenture for the Company to provide or deliver any security for its obligations under the Loan Agreement.

The Bonds will accrue interest at the Term Interest Rate as set forth on the cover page hereof until the Maturity Date thereof. Except as otherwise described herein, interest on the Bonds will be payable semiannually as set forth on the cover page hereof. The Bonds are subject to optional redemption, extraordinary optional and special mandatory redemption, all as described herein. See "THE BONDS – Redemption."

The Bonds are special and limited obligations of the Issuer and will be payable solely from and secured exclusively by payments, revenues and other amounts pledged thereto pursuant to the

Indenture. The Bonds do not represent or constitute a debt or pledge of the faith and credit or taxing power of the Issuer or the Commonwealth of Kentucky (the "*State*") or any political subdivision thereof and the holders and owners of the Bonds will have no right to have taxes levied by the Issuer or the State or any political subdivision or other taxing authority of the State for the payment or redemption price of, and interest on, the Bonds.

Brief descriptions of the Issuer, the Bonds, the Loan Agreement and the Indenture are included in this Reoffering Circular. Certain information with respect to the Company is included or incorporated by reference in Appendix A hereto. Appendix B sets forth Certain Definitions. Appendix D attached to this Reoffering Circular contains the text of the Original Bond Counsel opinion delivered in connection with the issuance and delivery of the Bonds.

All references herein to the documents are qualified in their entirety by reference to such documents, and references herein to the Bonds are qualified in their entirety by reference to the definitive forms thereof included in the Indenture. Copies of certain of the financing documents may be obtained from the Trustee at the Designated Office of the Trustee. Appendix A to this Reoffering Circular and all information contained under the heading "APPLICATION OF PROCEEDS" has been furnished by the Company. The information contained under the heading "THE BONDS – Book-Entry-Only System" has been furnished by DTC, and none of the Issuer, the Company, the Remarketing Agents or Original Bond Counsel assumes any responsibility for the accuracy or completeness of such information.

THE ISSUER

The Issuer is a body corporate and politic duly created and existing as a de jure county and political subdivision under the constitution and laws of the State. Pursuant to Section 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (the "*Act*"), the Issuer issued the Bonds and loaned the proceeds thereof to the Company for the purpose of refunding the Prior Bonds. In connection with the original issuance of the Prior Bonds, the Issuer, through its legislative body, the Fiscal Court, adopted an ordinance authorizing the issuance of the Prior Bonds and the execution and delivery of related documents.

The Issuer has not participated in the preparation of this Reoffering Circular and, except for the information appearing herein under the caption "THE ISSUER," makes no representation as to its adequacy or accuracy.

APPLICATION OF PROCEEDS

All of the proceeds of the Bonds were used, together with any funds provided by the Company, to refund all of the outstanding Prior Bonds. The proceeds of the Prior Bonds were applied to refinance the Company's portion of the costs of certain air and water pollution and solid waste disposal facilities located at the East Bend Generating Station.

THE BONDS

General

The Bonds mature on August 1, 2027 (the "*Maturity Date*") and are subject to optional redemption, extraordinary optional and special mandatory redemption, all as described below. See "THE BONDS – Redemption."

The Bonds were issued solely in book-entry form to DTC or its nominee, Cede & Co., and are held in DTC's book-entry-only system. So long as the Bonds are held in the book-entry-only system, DTC (or a successor securities depository) or its nominee will be the registered owner or holder of the Bonds for all purposes of the Indenture, the Bonds and this Reoffering Circular. See "— Book-Entry-Only System" below. Except as described under "— Book-Entry-Only System" below, Beneficial Owners (as defined below) of the Bonds will not receive or have the right to receive physical delivery of certificates representing their ownership interests in the Bonds. For so long as any purchaser is the Beneficial Owner of a Bond, such purchaser must maintain an account with a broker or dealer who is, or acts through, a Direct Participant (as defined below) to receive payment of the principal or redemption price of, interest on, and purchase price of, such Bond.

The Bonds will bear interest on the unpaid principal amount thereof at the Term Interest Rate as set forth on the cover page hereof until maturity.

Interest on the Bonds will be computed on the basis of a 360-day year of twelve 30-day months. Interest on the Bonds will be payable semiannually on December 1 and June 1 of each year, commencing on December 1, 2022. Interest payable on any Interest Payment Date (as defined below) will be payable to the registered owner of such Bonds of the Regular Record Date (as defined below) for such payment.

So long as the Bonds are held in the book-entry-only system, the principal or redemption price of and interest on, and purchase price of, the Bonds will be paid through the facilities of DTC (or a successor securities depository). Otherwise, the principal or redemption price of, and purchase price of, the Bonds is payable upon presentation and surrender thereof at the payment office of the Trustee, as paying agent (the "*Paying Agent*"); and interest on the Bonds is payable by check mailed on the applicable Interest Payment Date by first class mail, postage prepaid, to the owner of record.

If use of the book-entry-only system is discontinued and the Bonds are issued in certificated form, Bonds will be transferred or exchanged for an equal total principal amount of Bonds in the same Interest Rate Mode and in authorized denominations upon surrender of such Bonds at the office of the Bond Registrar, accompanied by a written instrument of transfer or authorization for exchange with guaranty of signature or medallion stamp satisfactory to the Trustee, duly executed by the registered owner or the owner's authorized attorney. Except as provided in the Indenture, the Bond Registrar will not be required to register the transfer or exchange of any Bond during the fifteen days before any mailing of a notice of redemption or after such Bond has been called for redemption or the Bond has been subject to mandatory purchase. Registration of transfers and exchanges will be made without charge to the owners of Bonds, except that the Authority may require any owner requesting registration of transfer or exchange to pay any required tax or governmental charge

Redemption

Optional Redemption. The Bonds will be subject to optional redemption by the Issuer at the direction of the Company, in whole or in part, on or after June 27, 2027, at a redemption price of 100% of the principal amount of the Bonds to be redeemed, plus accrued and unpaid interest, if any, to the redemption date.

Extraordinary Optional Redemption. The Bonds are subject to redemption by the Issuer at the direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount redeemed, plus accrued and unpaid interest to the redemption date upon the occurrence of any of the following events.

(a) The Project or the Generating Station is damaged or destroyed to such an extent that (1) the Project Facilities or the Generating Station cannot reasonably be expected to be restored, within a period of six consecutive months, to the condition thereof immediately preceding such damage or destruction or (2) the Company is reasonably expected to be prevented from carrying on its normal use and operation of the Project Facilities or the Generating Station for a period of six consecutive months.

(b) Title to, or the temporary use of, all or a significant part of the Project Facilities or the Generating Station is taken under the exercise of the power of eminent domain to such extent that (1) the Project Facilities or the Generating Station cannot reasonably be expected to be restored within a period of six consecutive months to a condition of usefulness comparable to that existing prior to the taking or (2) the Company is reasonably expected to be prevented from carrying on its normal use and operation of the Project Facilities or the Generating Station for a period of six consecutive months.

(c) As a result of any changes in the Constitution of the State, the Constitution of the United States of America or any state or federal laws or as a result of legislative or administrative action (whether state or federal) or by final decree, judgment or order of any court or administrative body (whether state or federal) entered after any contest thereof by the Issuer or the Company in good faith, the Loan Agreement becomes void or unenforceable or impossible of performance in accordance with the intent and purpose of the parties as expressed in the Loan Agreement.

(d) Unreasonable burdens or excessive liabilities are imposed upon the Issuer or the Company with respect to the Project Facilities or the Generating Station or the operation thereof, including, without limitation, the imposition of federal, state or other ad valorem, property, income or other taxes other than ad valorem taxes at the rates presently levied upon privately owned property used for the same general purpose as the Project Facilities or the Generating Station.

(e) Changes in the economic availability of raw materials, operating supplies, energy sources or supplies or facilities (including, but not limited to, facilities in connection with the disposal of industrial wastes) necessary for the operation of the Project Facilities or the Generating Station for the Project Purposes occur or technological or other changes occur which the Company cannot reasonably overcome or control and which in the Company's reasonable judgment render the Project Facilities or the Generating Station uneconomic or obsolete for the Project Purposes.

(f) Any court or administrative body enters a judgment, order or decree, or takes administrative action, requiring the Company to cease all or any substantial part of its operations served by the Project Facilities or the Generating Station to such extent that the Company is or will be prevented from carrying on its normal operations at the Project or the Generating Station for a period of six consecutive months.

(g) The termination by the Company of operations at the Generating Station.

Mandatory Redemption Upon a Determination of Taxability. The Bonds are subject to mandatory redemption by the Issuer at a redemption price of 100% of the outstanding principal amount thereof, plus interest accrued to the redemption date, at the earliest practicable date selected by the Trustee, after consultation with the Company, but in no event later than 180 days following the receipt by the Trustee of notification of a Determination of Taxability, as defined below. Such redemption will be either in whole or, if in the Opinion of Bond Counsel the Determination of Taxability will not apply to Bonds remaining outstanding after such redemption, in part.

A *"Determination of Taxability"* means written notice from the Company of the occurrence of a final decision, ruling or technical advice by any federal judicial or administrative authority to the effect that, as a result of a failure by the Company to observe or perform any covenant, agreement or obligation on its part to be observed or performed under the Loan Agreement or the inaccuracy of any representation made by the Company in the Loan Agreement, interest on any Bond is or was includable in the gross income of the owner of that Bond for federal income tax purposes, other than an owner who is a "substantial user" of the Project or a "related person" as those terms are used in Section 147(a) of the Code; provided that, no decision by any court or decision, ruling or technical advice by any administrative authority will be considered final (a) unless the beneficial owner involved in the proceeding or action giving rise to such decision, ruling or technical advice (i) gives the Company and the Trustee prompt notice of the commencement thereof, together with evidence satisfactory to the Company and the Trustee that such party is the beneficial owner and (ii) offers the Company the opportunity to control the contest thereof, provided that the Company has agreed to bear all expenses in connection therewith and to indemnify the beneficial owner against all liabilities in connection therewith, and (b) until the expiration of all periods for judicial review or appeal. A Determination of Taxability will not result from the inclusion of interest on any Bond in the computation of the alternative minimum tax imposed by Section 55 of the Code, the branch profits tax on foreign corporations imposed by Section 884 of the Code or the tax imposed on net excess passive income of certain S corporations under Section 1375 of the Code.

If the Indenture has been released in accordance with its terms prior to the occurrence of a Determination of Taxability, the Bonds will not be subject to mandatory redemption.

Partial Redemption. If fewer than all of the Bonds are to be redeemed, the selection of Bonds to be redeemed, or portions thereof in amounts equal to the lowest Authorized Denomination, shall be made by lot by the Trustee in any manner which the Trustee may determine. In the case of a partial redemption of Bonds by lot when Bonds of denominations greater than the lowest Authorized Denomination are then outstanding, each unit of face value of principal thereof equal to the lowest Authorized Denomination will be treated as though it were a separate Bond of such lowest Authorized Denomination. If it is determined that one or more, but not all of the units of face value represented by a Bond are to be called for redemption, then upon notice of redemption of a unit or units, the holder of that Bond will surrender the Bond to the Trustee (a) for payment of the redemption price of the unit or units of face value called for redemption (including without limitation, the interest accrued to the date fixed for redemption and any premium), and (b) for issuance, without charge to the holder thereof, of a new Bond or Bonds of any Authorized Denominations in an aggregate principal amount equal to the unmatured and unredeemed portion of the Bond surrendered.

Notice of Redemption. The Trustee will give notice of the redemption on behalf of the Issuer by mailing a copy of the redemption notice by first class mail, postage prepaid, at least 30 days but not more than 90 days prior to the redemption date, to the owner of each Bond subject to redemption in whole or in part. Failure to receive any such notice, or any defect therein in respect of any Bond, will not affect the validity of the redemption of any Bond. If at the time of mailing of the notice of redemption there has not been deposited with the Trustee moneys sufficient to redeem all Bonds called for redemption, if the Company so directs, such notice may state that it is conditional, subject to the deposit of moneys sufficient for the redemption with the Trustee not later than the redemption date and such notice will be of no effect unless such moneys are so deposited. If either (A) unconditional notice of redemption was mailed or (B) conditional notice was mailed and the moneys sufficient to redeem all Bonds on the redemption date have been deposited with the Trustee, then in either event, the Bonds and portions thereof called for redemption will become due and payable on the redemption date, and upon presentation and surrender thereof at the place or places specified in that notice, will be paid at the redemption price, plus interest accrued to the redemption date.

So long as Cede & Co., as nominee of DTC, is the registered owner of the Bonds, all notices of redemption will be sent only to Cede & Co., and delivery of notice of redemption to the Direct Participants, if any, will be solely the responsibility of DTC.

Book-Entry-Only System

The following information concerning DTC and DTC's book-entry only system has been obtained from DTC. The Issuer, the Remarketing Agents, the Company and the Trustee make no representation as to the accuracy of such information.

DTC will act as securities depository for the Bonds. The Bonds are fully- registered bonds registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered Bond certificate have been issued for each series of the Bonds, each in the aggregate principal amount of such series, and will be deposited with DTC.

DTC, the world's largest securities depository, is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934. DTC holds and provides asset servicing for over 3.5 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments (from over 100 countries) that DTC's participants ("*Direct Participants*") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("*DTCC*"). DTCC is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation, all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("*Indirect Participants*" and together with the Direct Participants, the "*Participants*"). DTC has a Standard & Poor's rating of AA+. The DTC Rules applicable to its Participants are on file with the Securities and Exchange Commission. More information about DTC can be found at www.dtcc.com.

Purchases of the Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for the Bonds on DTC's records. The ownership interest of each actual purchaser of Bonds ("*Beneficial Owner*") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the Bonds are to be accomplished by entries made on the books of Direct or Indirect Participants acting on behalf of Beneficial Owners.

Beneficial Owners will not receive certificates representing their ownership interests in the Bonds, except in the event that use of the book-entry system for the Bonds is discontinued.

To facilitate subsequent transfers, all Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co., or such other name as may be requested by an authorized representative of DTC. The deposit of Bonds with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not affect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time. Beneficial Owners may wish to take certain steps to augment the transmission to them of notices of significant events with respect to the Bonds, such as redemptions, tenders, defaults, and proposed amendments to the Bonds documents. For example, Beneficial Owners may wish to ascertain that the nominee holding the Bonds for their benefit has agreed to obtain and transmit notices to Beneficial Owners. In the alternative, Beneficial Owners may wish to provide their names and addresses to the registrar and request that copies of notices be provided directly to them. Redemption notices shall be sent to DTC. If less than all of the Bonds within an issue are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in such issue to be redeemed.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the Bonds unless authorized by a Direct Participant in accordance with DTC's MMI Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the Issuer as soon as possible after the Record Date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts the Bonds are credited on the Record Date (identified in a listing attached to the Omnibus Proxy).

Redemption proceeds and principal and interest payments on the Bonds will be made to Cede & Co., or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts upon DTC's receipt of funds and corresponding detail information from the Trustee or the Issuer, on the date payable in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such Participant and not of DTC, the Issuer, the Trustee or its agent, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of redemption proceeds and principal and interest to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of the Trustee. Disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

DTC may discontinue providing its services as securities depository with respect to the Bonds at any time by giving reasonable notice to the Issuer or the Trustee. Under such circumstances, in the event that a successor securities depository is not obtained, Bond certificates are required to be printed and delivered.

The Issuer may decide to discontinue use of the system of book-entry only transfers through DTC (or a successor securities depository). In that event, Bond certificates will be printed and delivered.

NEITHER THE ISSUER, THE COMPANY, NOR THE TRUSTEE SHALL HAVE ANY RESPONSIBILITY OR OBLIGATION TO ANY DTC PARTICIPANT OR ANY BENEFICIAL OWNER OR ANY OTHER PERSON NOT SHOWN ON THE REGISTRATION BOOKS OF THE TRUSTEE AS BEING A BONDHOLDER WITH RESPECT TO EITHER: (1) THE ACCURACY OF ANY RECORDS MAINTAINED BY DTC OR ANY DTC PARTICIPANT; (2) THE PAYMENT BY DTC OR ANY DTC PARTICIPANT OF ANY AMOUNT DUE TO ANY BENEFICIAL OWNER IN RESPECT OF THE PRINCIPAL OR REDEMPTION PRICE OF OR INTEREST ON THE BONDS; (3) THE DELIVERY OR THE TIMELINESS OF ANY NOTICE TO ANY BENEFICIAL OWNER WHICH IS REQUIRED OR PERMITTED UNDER THE TERMS OF THE INDENTURE TO BE GIVEN TO THE OWNER OF THE BONDS; OR (4) ANY CONSENT GIVEN OR OTHER ACTION TAKEN BY DTC AS BONDHOLDER.

THE INFORMATION IN THIS SECTION CONCERNING DTC AND DTC'S BOOK-ENTRY SYSTEM HAS BEEN OBTAINED FROM DTC. THE ISSUER, THE COMPANY AND THE REMARKETING AGENTS TAKE NO RESPONSIBILITY FOR THE ACCURACY OR COMPLETENESS THEREOF.

Revision of Book-Entry-Only System; Replacement Bonds

The Issuer, pursuant to a request by the Company and the Remarketing Agent, if any, for the removal or replacement of the Depository or the discontinuance of the book-entry-only system for the Bonds, and upon 30 days' notice to the Depository and the Trustee, will agree to remove or replace the Depository or discontinue the book-entry-only system for the Bonds.

In the event that the book-entry-only system is discontinued, the following provisions will apply. The Bonds may be issued in Authorized Denominations. Bonds may be transferred or exchanged in Authorized Denominations upon surrender of such Bonds at the principal office of the Trustee, accompanied by an assignment satisfactory to the Trustee, duly executed by the Owner or the Owner's duly authorized attorney-in-fact. Neither the Issuer nor the Trustee will be required to make any such transfer or exchange of any Bond during the period beginning at the opening of business 15 days immediately preceding the mailing of a notice of Bonds selected for redemption and ending at the close of business on the day of such mailing, or, with respect to a Bond, after such Bond or any portion thereof has been selected for redemption. The Issuer or the Trustee may make a charge to the Owner for every transfer or exchange of a Bond sufficient to reimburse it for any tax or other governmental charge required to be paid with respect to such transfer or exchange, and may demand that such charge be paid before any new Bond is delivered.

THE LOAN AGREEMENT

The following is a brief summary of certain provisions of the Loan Agreement and does not purport to be comprehensive or definitive. Reference is made to the Loan Agreement for the detailed provisions thereof.

Loan of Proceeds

The Issuer loaned the proceeds of the sale of the Bonds to the Company, in accordance with the Loan Agreement and the Indenture, to pay a portion of the costs of redeeming the Prior Bonds.

Application of Proceeds

All of the proceeds of the Bonds were used, together with any funds provided by the Company, to refund the Prior Bonds.

Loan Payments

The Company is obligated to make Loan Payments under the Loan Agreement which correspond, as to time, and are equal in amount, to the amount then payable as principal of and premium, if any, and interest on the Bonds. All payments under the Loan Agreement related to the Loan have been assigned to the Trustee, and the Company will make such payments directly to the Trustee for the account of the Issuer and for deposit in the Bond Fund created under the Indenture.

Obligation to Purchase Bonds

The Company has agreed to pay or cause to be paid to the Trustee or the Paying Agent, on or before each day on which Bonds may be or are required to be tendered for purchase, amounts equal to the amounts to be paid by the Trustee or the Paying Agent with respect to the Bonds tendered for purchase on such dates pursuant to the Indenture; provided, however, that the obligation of the Company to make any such payment will be reduced by the amount of (A) moneys paid by the Remarketing Agent as proceeds of the remarketing of such Bonds by the Remarketing Agent and (B) other moneys made available by the Company.

Term of Loan Agreement

The Loan Agreement will remain in full force and effect until such time as (i) all of the Bonds are fully paid (or provision has been made for such payment) pursuant to the Indenture and the Indenture has been released pursuant to the terms thereof and (ii) all other sums payable by the Company under the Loan Agreement have been paid.

Maintenance and Modification

During the term of the Loan Agreement, the Company will use its best efforts to keep and maintain the Project Facilities in good repair and good operating condition so that the Project Facilities will continue to constitute Pollution Control Facilities (as defined in the Loan Agreement) for the purposes of the operation thereof.

Subject to certain conditions, the Company has the right, from time to time, to remodel the Project Facilities or make additions, modifications and improvements thereto, the cost of which must be paid by the Company. The Company also has the right, subject to certain conditions, to substitute or remove any portion of the Project Facilities.

Maintenance of Corporate Existence

The Company agrees that, during the term of the Loan Agreement, it will maintain its existence, will not dissolve or otherwise dispose of all or substantially all of its assets and will not consolidate with or merge into another corporation or other entity or permit one or more other corporations or other entities to consolidate with or merge into it; provided that the Company may, without violating its agreement contained in the Loan Agreement, consolidate with or merge into another corporation or other entity, or permit one or more other entities to consolidate with or merge into it, or sell or otherwise transfer to another entity all or substantially all of its assets as an entirety and thereafter dissolve, provided the surviving, resulting or transferee entity, as the case may be (if other than the Company), is a corporation or other entity organized and existing under the laws of one of the states of the United States, and assumes in writing all of the obligations of the Company in the Loan Agreement, and, if not organized under the laws of Kentucky, is qualified to do business in the State.

Tax Covenant

The Company has covenanted and represented in the Loan Agreement that it has taken and caused to be taken and will take and cause to be taken all actions that may be required of it for the interest on the Bonds to be and remain excluded from the gross income of the owners thereof for federal income tax purposes, and that it has not taken or permitted to be taken on its behalf, and it will not take or permit to be taken on its behalf, any action which, if taken, would adversely affect that exclusion under the provisions of the Code.

Assignment by Company

Notwithstanding any other provisions of the Loan Agreement, the Loan Agreement may be assigned in whole or in part by the Company and the Project may be sold or conveyed by the Company without the necessity of obtaining the consent of either the Issuer or the Trustee and after providing written notice to the Issuer but, subject, however, to each of the following conditions:

(a) the Company must provide the Trustee and the Remarketing Agent with an Opinion of Bond Counsel that such action will not affect the exclusion of interest on the Bonds for federal income tax purposes;

(b) the Company must, within 30 days after the execution thereof, furnish or cause to be furnished to the Issuer and the Trustee a true and complete copy of each such assignment together with any instrument of assumption; and

(c) Any assignment from the Company may not materially impair fulfillment of the Project Purposes to be accomplished by operation of the Project as provided in the Loan Agreement.

Events of Default and Remedies

The Loan Agreement provides that the occurrence of each of the following events will constitute an "event of default":

(a) The occurrence of an event of default described in paragraphs (a), (b), (c) or (d) under "THE INDENTURE – Events of Default";

(b) Failure by the Company to observe and perform any other agreement, term or condition contained in the Loan Agreement, other than a failure as has resulted in an event of default described in (a) above, which failure continues for a period of 90 days after notice by the Issuer or the Trustee, or for such longer period as the Issuer and the Trustee agree to in writing; provided, that such failure will not constitute an event of default so long as the Company institutes curative action within the applicable period and diligently pursues that action to completion within 150 days after the expiration of the initial 90 day cure period or within such longer period as the Issuer and the Trustee may agree to in writing; and

(c) The occurrence of certain voluntary or involuntary events of bankruptcy, reorganization or receivership with respect to the Company.

A failure by the Company described in paragraph (b) above will not be a default if it occurs by reason of certain events of "force majeure" specified in the Loan Agreement not reasonably within the control of the Company.

Whenever any event of default under the Loan Agreement has happened and is subsisting, either or both of the following remedial steps may be taken by the Issuer or the Trustee:

(a) Have access to, inspect, examine and make copies of the books, records, accounts, and financial data of the Company, only, however, insofar as they pertain to the Project; or

(b) Pursue all remedies existing at law or in equity to recover all amounts then due and thereafter to become due under the Loan Agreement or to enforce performance and observance of any other obligation or agreement of the Company under the Loan Agreement.

Any amounts collected pursuant to action taken upon the happening of an event of default will be paid into the Bond Fund and applied pursuant to the Indenture.

Amendment to the Loan Agreement

The Indenture provides that the Loan Agreement may be amended without the consent of or notice to the holders of the Bonds only as may be required (i) by the provisions of the Loan Agreement or the Indenture, (ii) for the purpose of curing any ambiguity, inconsistency or formal defect or omission therein, (iii) in connection with an amendment or to effect any purpose for which there could be an amendment of the Indenture not requiring the consent of holders, or (iv) in connection with any other change therein which, in the judgment of the Trustee, is not to the material prejudice of the Trustee or the holders of the Bonds. The Loan Agreement may be amended, but only with the consent of the holders of all of the outstanding Bonds, to change the amounts or times as of which Loan Payments under the Loan Agreement are required to be made. Any other amendments to the Loan Agreement may be made only with the written approval or consent of the holders of not less than a majority in aggregate principal amount of the Bonds outstanding.

Before the Issuer and the Trustee may consent to any amendment to the Loan Agreement, there must be delivered to the Trustee an Opinion of Bond Counsel stating that such amendment is authorized or permitted by the Act and is authorized under the Indenture, that such amendment will, upon the execution and delivery thereof, be valid and binding in accordance with its terms, and that such amendment will not adversely affect the exclusion from gross income of the interest on the Bonds for federal income tax purposes.

THE INDENTURE

In addition to the description of certain provisions of the Indenture contained elsewhere herein, the following is a brief summary of certain provisions of the Indenture and does not purport to be comprehensive or definitive. Reference is made to the Indenture for the detailed provisions thereof.

Pledge of Revenues

Pursuant to the Indenture, all right, title and interest of the Issuer in and to the "Revenues" (as defined below) and under the Loan Agreement (except for certain rights of the Issuer), are pledged or assigned to the Trustee to secure the payment of the principal or redemption price of and interest on the Bonds.

"Revenues" are defined to mean: (a) the Loan Payments, (b) all other moneys received or to be received by the Issuer (excluding any fees paid to the Issuer) or the Trustee in respect of repayment of the Loan including, without limitation, all moneys and investments in the Bond Fund, and (c) all income and profit from the investment of the foregoing moneys. The term "Revenues" does not include any moneys or investments in the Rebate Fund or the Bond Purchase Fund as those terms are defined in the Indenture.

Bond Fund

A Bond Fund has been established with the Issuer and is maintained by the Trustee as a trust fund under the Indenture. The amounts with respect to the payment of principal of and premium, if any, and interest on the Bonds derived under the Loan Agreement and certain other amounts specified in the Indenture will be deposited in the Bond Fund. While the Bonds are outstanding, moneys in the Bond Fund will be used solely for the payment of the principal or redemption price of and interest on the Bonds as they become due on any Interest Payment Date or at stated maturity, by redemption or upon acceleration.

Investments

Any moneys held as a part of the Bond Fund and the Rebate Fund will be invested and reinvested by the Trustee as provided in the Indenture. Any such investments will be held by or under the control of the Trustee and will be deemed at all times a part of the respective fund.

Events of Default

The Indenture provides that each of the following events will constitute an "Event of Default" thereunder:

(a) Payment of any interest on any Bond is not made when it becomes due and payable;

(b) Payment of the principal or redemption price of any Bond is not made when it becomes due and payable, whether at stated maturity, by redemption, by acceleration or otherwise;

(c) [Intentionally omitted]

(d) Failure by the Issuer to observe or perform any other covenant, agreement or obligation on its part to be observed or performed contained in the Bonds or the Indenture (other than a failure described in paragraphs (a) or (b) above), which failure has continued for a period of 90 days after written notice (or for such longer period as the Trustee may agree to in writing), by registered or certified mail, to the Issuer and the Company given by the Trustee, either in its discretion or at the written request of the holders of not less than 35% in aggregate principal amount of Bonds then outstanding; provided, that failure will not constitute an Event of Default so long as the Issuer institutes curative action within the applicable period and diligently pursues that action to completion within 150 days after the expiration of the initial cure period as determined above, or within such longer period as the Trustee may agree to in writing; or

(e) The occurrence and continuance of an event of default as described in paragraph (c) under "THE LOAN AGREEMENT – Events of Default and Remedies."

Remedies

Upon the occurrence and continuance of any Event of Default described in subsections (a), (b), (d) or (e) under "Events of Default" above, the Trustee may, and upon the written request of the Holders of not less than 35% in aggregate principal amount of Bonds then outstanding.

Interest on the Bonds will accrue at the rates per annum borne by the Bonds to the date determined by the Trustee for the tender of payment to the Holders pursuant to that declaration; provided, that interest on any unpaid principal of Bonds outstanding will continue to accrue from the date determined by the Trustee for the tender of payment to the Holders of those Bonds until that principal amount has been paid or made available to the Trustee for the benefit of the Holders. The Trustee will immediately give written notice of such declaration by mail to the Holders of all Bonds then outstanding as shown by the Register at the close of business on the day prior to the mailing of that notice.

The provisions above are subject to the condition that if at any time after declaration of acceleration and prior to the entry of a judgment in a court for enforcement (after an opportunity for hearing by the Issuer and the Company), all sums payable (except the principal of and interest on Bonds which have not reached their stated maturity dates but which are due and payable solely by reason of that declaration of acceleration), plus interest to the extent permitted by law on any overdue installments of interest at the rate then borne by the Bonds, have been duly paid or provision therefor having been made by deposit with the Trustee or Paying Agent and all existing Events of Default have been cured, then such payment or provision for payment will constitute an automatic waiver of the Event of Default and its consequences and will constitute an automatic rescission and annulment of that declaration.

With or without taking action to accelerate the Bonds as described above, upon the occurrence and continuance of an Event of Default, the Trustee may pursue any available remedy to enforce the payment of Bond Service Charges or the observance and performance of any other covenant, agreement or obligation under the Indenture, the Agreement or any other instrument providing security, directly or indirectly, for the Bonds. If, upon the occurrence and continuance of an Event of Default, the Trustee is requested so to do by the Holders of at least 35% in aggregate principal amount of Bonds outstanding, the Trustee (subject to the provisions of the Indenture), will exercise any rights and powers conferred by the Indenture.

Anything to the contrary in the Indenture notwithstanding, the Holders of a majority in aggregate principal amount of Bonds then outstanding, if the Event of Default is under any other subsection under "Events of Default" above, will have the right at any time to direct, by an instrument or document or instruments or documents in writing executed and delivered to the Trustee, the time, method and place of conducting all proceedings to be taken in connection with the enforcement of the terms and conditions of the Indenture or any other proceedings thereunder; provided, that (i) any direction may not be other than in accordance with the provisions of law and of the Indenture, (ii) the Trustee is indemnified as provided in the Indenture, and (iii) the Trustee may take any other action which it deems to be proper and which is not inconsistent with the direction.

All moneys received under the Indenture by the Trustee upon the occurrence of an Event of Default will be applied first to the payment of the costs and expenses of the proceedings resulting in the collection of such money and of the fees and expenses incurred by the Trustee, and the balance of such money will be deposited in the Bond Fund and applied to the payment of the principal of and premium, if any, and interest on the Bonds in the manner and in the priorities set forth in the Indenture. The Trustee will have a first lien against the trust estate, payable prior to debt service on the Bonds.

No holder of any Bond will have any right to institute any suit, action or proceeding for the enforcement of the Indenture or for the exercise of any other remedy under the Indenture, unless (i) an Event of Default has occurred and is continuing and the Trustee has or is deemed to have notice of the same, (ii) the holders of not less than 35% in aggregate principal amount of the then outstanding Bonds have made written request to the Trustee and have afforded the Trustee reasonable opportunity to proceed to exercise the remedies, rights and powers granted by the Indenture or to institute a suit, action or proceeding in its own name and have offered to the Trustee satisfactory indemnity as provided in the Indenture, and (iii) the Trustee thereafter has failed or refused to exercise the remedies, rights and powers granted under the Indenture or to institute such action, suit or proceeding in its own name. Notwithstanding the foregoing, each holder of a Bond will have a right to enforce the payment of the principal of and premium, if any, and interest on any Bond held or owned by that holder at and after the maturity thereof at the place, from the sources and in the manner expressed in said Bond.

Supplemental Indentures

The Issuer and the Trustee may, without the consent of, or notice to, any holder of a Bond, enter into supplemental indentures which will not, in the opinion of the Issuer and the Trustee, be inconsistent with the Indenture for any one or more of the following purposes:

(a) To cure any ambiguity, inconsistency or formal defect or omission in the Indenture;

(b) To grant to or confer upon the Trustee for the benefit of the holders of the Bonds any additional rights, remedies, powers or authority that lawfully may be granted to or conferred upon the holders or the Trustee;

(c) To assign additional revenues under the Indenture;

(d) To accept additional security and instruments and documents of further assurance with respect to the Project, including without limitation, first mortgage bonds of the Company;

(e) To add to the covenants, agreements and obligations of the Issuer under the Indenture, other covenants, agreements and obligations to be observed for the protection of the holders of the Bonds, or to surrender or limit any right, power or authority reserved to or conferred upon the Issuer in the Indenture;

(f) To evidence any succession to the Issuer and the assumption by its successor of the covenants, agreements and obligations of the Issuer under the Indenture, the Loan Agreement and the Bonds;

(g) To permit the exchange of Bonds, at the option of the holder or holders thereof, for coupon Bonds payable to bearer, if the Trustee has received an Opinion of Bond Counsel to the effect that the exchange would not adversely affect the exclusion from gross income for federal income tax purposes of the interest on the Bonds outstanding;

(h) To permit the transfer of Bonds from one Depository to another, and the succession of Depositories, or the withdrawal of Bonds issued to a Depository for use in a book entry system and the issuance of replacement Bonds in fully registered form to others than a Depository;

(i) To permit the Trustee to comply with any obligations imposed upon it by law;

(j) To specify further the duties and responsibilities of, and to define further the relationship among, the Trustee, the Registrar, the Remarketing Agent, and any authenticating agents or Paying Agents;

(k) To achieve compliance of the Indenture with any applicable federal securities or tax law;

(l) To make amendments to the provisions of the Indenture relating to arbitrage matters under Section 148(f) of the Code, if, in the opinion of Bond Counsel, those amendments would not adversely affect the exclusion from gross income for federal income tax purposes of the interest on the Bonds outstanding; and

(m) To permit any other amendment which, in the judgment of the Trustee, is not to the material prejudice of the Trustee or the holders of the Bonds.

Exclusive of such supplemental indentures, the holders of not less than a majority in aggregate principal amount of the Bonds then outstanding, and, if required by the Indenture, of the Company, will have the right to consent to and approve any supplemental indenture, except that no supplemental indenture will permit:

(a) An extension of the maturity of the principal of or the date for payment of interest on any Bond, a reduction in the principal amount of any Bond or the rate of interest or premium thereon; or

(b) The creation of a privilege or priority of any Bond or Bonds over any other Bond or Bonds, or a reduction in the aggregate principal amount of the Bonds required for consent to a supplemental indenture, without the consent of the holders of all of the Bonds then outstanding.

Any supplemental indenture which affects the rights or obligations of the Company requires the written consent of the Company. Before the Issuer and the Trustee may enter into any supplemental indenture, there must be delivered to the Trustee an Opinion of Bond Counsel stating that such supplemental indenture is authorized or permitted by the Act and is authorized under the Indenture, that such supplemental indenture will, upon the execution and delivery thereof, be valid and binding in accordance with its terms, and that such supplemental indenture will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes.

Discharge of Indenture

The lien created by the Indenture will be discharged when the Issuer pays or causes to be paid, or if there otherwise is paid, to or for the holders of the Bonds the principal, premium, if any, and interest due or to become due thereon and provision is also made for the payment of all other sums payable pursuant to the provisions of the Indenture and the Loan Agreement.

All of the Bonds will be deemed to have been paid and discharged within the meaning of the Indenture if:

(a) The Trustee as paying agent and any Paying Agents have received, in trust for and irrevocably committed thereto, sufficient moneys, or

(b) The Trustee has received, in trust for and irrevocably committed thereto, non-callable and non-prepayable Government Obligations which are certified by an independent public accounting firm of national reputation (with a copy of the certification being delivered to the Rating Agencies) to be of such maturities or redemption dates and interest payment dates, and to bear such interest as will be sufficient together with moneys referred to in (a) above, without further investment or reinvestment of either the principal amount thereof or the interest earnings therefrom, for the payment of all principal of and premium, if any, and interest on such Bonds at their maturity or redemption dates, as the case may be; provided, that if any of such Bonds are to be redeemed prior to maturity, notice of such redemption must have been duly given or irrevocable provision satisfactory to the Trustee must have been duly made for the giving of such notice.

No Personal Liability of Issuer's Officials

No covenant, stipulation, obligation or agreement of the Issuer contained in the Indenture will be or be deemed to be a covenant, stipulation, obligation or agreement of any present or future member, officer, agent or employee of the Issuer in other than his or her official capacity. No official of the Issuer executing the Bonds, the Indenture, the Loan Agreement (or amendments or supplements to either) will be liable personally on the Bonds or be subject to any personal liability or accountability by reason of the issuance thereof or the execution of the Indenture or the Loan Agreement (or amendments or supplements to either).

The Trustee

Except for any period during which an Event of Default, of which the Trustee has been notified or is deemed to have knowledge, has occurred and is continuing, the Trustee (i) will undertake to perform only the duties specifically set forth in the Indenture and (ii) in the absence of bad faith on its part, may rely conclusively upon the truth of the statements and the correctness of the opinions furnished to it pursuant to the Indenture. In case an Event of Default has occurred and is continuing (of which the Trustee has been notified or is deemed to have notice), the Trustee will exercise the rights and powers vested in it by the Indenture and will use the same degree of care and skill as a prudent person would use under the circumstances in the conduct of his or her own affairs. The Trustee will not be required to expend or risk its own funds in performing its duties under the Indenture and will be entitled to compensation and the reimbursement of its expenses.

The Trustee may resign at any time from the trusts created by the Indenture by giving written notice of the resignation to the Issuer, the Company, the Registrar, any Paying Agents, the Remarketing Agents, and authenticating agents and by mailing written notice thereof to the holders of the Bonds. The resignation will take effect only upon the appointment of a successor Trustee and the successor's acceptance of the appointment.

The Trustee may be removed at any time by the holders of not less than a majority in aggregate principal amount of the Bonds then outstanding. The removal will take effect only upon the appointment of a successor Trustee and such successor's acceptance of the appointment, all pursuant to the provisions of the Indenture. The Trustee also may be removed at any time for any breach of trust or for acting or proceeding in violation of, or for failing to act or proceed in accordance with, any provision of the Indenture with respect to the duties and obligations of the Trustee by any court of competent jurisdiction upon the application of the Issuer, upon its own volition or at the written request of the Company or the holders of not less than 35% in aggregate principal amount of the Bonds then outstanding under the Indenture. The removal will take effect only upon the appointment of a successor Trustee and such successor's acceptance of the appointment, all pursuant to the provisions of the Indenture.

Every successor Trustee appointed pursuant to the Indenture (i) must be a trust company or a bank having the powers of a trust company, (ii) must be willing to accept the trusteeship on the terms and conditions of the Indenture, (iii) must have a reported capital and surplus of not less than $75,000,000, (iv) so long as the Bonds are rated by Moody's, must be acceptable to Moody's, and (v) so long as the Bonds are rated by S&P, must be acceptable to S&P.

TAX MATTERS

The opinion of Frost Brown Todd LLC, Bond Counsel ("*Original Bond Counsel*"), delivered in connection with the original issuance of the Bonds stated that under existing laws, regulations, judicial decisions and rulings, interest on the Bonds is excludable from gross income under section 103 of the Code for federal income tax purposes, except for interest on any Bond for any period during which such Bond is owned by a person who is a "substantial user" of the facilities financed by the Bonds or a "related person" as defined in Section 147(a) of the Code. The opinion relates only to the exclusion from gross income of interest on the Bonds for federal income tax purposes under Section 103 of the Code and is conditioned on continuing compliance by the Issuer and the Company with the Tax Covenants (hereinafter defined). Failure to comply with the Tax Covenants could cause interest on the Bonds to lose the exclusion from gross income for federal income tax purposes retroactive to the date of issue. The opinion of Frost Brown Todd LLC, Original Bond Counsel, delivered in connection with the original issuance of the Bonds, further stated that under existing laws, regulations, judicial decisions and rulings, interest on the Bonds is exempt from income taxation in the State. Such opinion relates only to the exemption of interest on the Bonds for State income tax purposes. The text of such Original Bond Counsel opinion is included in Appendix D to this Reoffering Circular but the opinion speaks only as of the date of initial delivery of the Bonds and will not be reissued in connection with the reoffering of the Bonds.

The Code imposes certain requirements which must be met subsequent to the issuance of the Bonds as a condition to the exclusion from gross income of interest on the Bonds for federal income tax purposes. In the Indenture and the Loan Agreement, the Issuer has made certain covenants, and in the Loan Agreement the Company has made certain covenants (collectively, the "*Tax Covenants*") concerning actions to be or not to be taken to preserve the tax status of the Bonds. The Indenture, Loan Agreement and certain certificates and agreements delivered on the date of delivery of the Bonds established procedures under which compliance with the requirements of the Code can be met.

The opinion of Original Bond Counsel was based on then-current legal authority and covers certain matters not directly addressed by such authority. It represents such counsel's legal judgment as to exclusion of interest on the Bonds from gross income for federal income tax purposes but is not a guaranty of that conclusion. The opinion is not binding on the Internal Revenue Service ("*IRS*") or any court. Original Bond Counsel expressed no opinion about (i) the effect of future changes in the Code and the applicable regulations under the Code or (ii) the interpretation and the enforcement of the Code or those regulations by the IRS. After the date of issuance of the Bonds, Original Bond Counsel did not undertake to determine (or to so inform any person) whether any actions taken or not taken, or any events occurring or not occurring, or any other matters coming to Original Bond Counsel's attention, may adversely affect the exclusion from gross income for federal income tax purposes of interest on the Bonds or the market prices of the Bonds.

Interest on the Bonds may be subject to a federal branch profits tax imposed on certain foreign corporations doing business in the United States and to a federal tax imposed on excess net passive income of certain S corporations.

The Code also subjects taxpayers to an alternate minimum tax on a taxpayer's "alternative minimum taxable income," which, in general terms, consists of a taxpayer's regular taxable income plus its preferences and special adjustments with respect to certain deductions used by a corporation to compute taxable income. Interest on the Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes. However, interest on the Bonds is included in adjusted current earnings in calculating corporate alternative minimum taxable income for the purpose of the corporate alternative minimum tax.

Under the Code, the exclusion of interest from gross income for federal income tax purposes may have certain adverse federal income tax consequences on items of income, deduction or credit for certain taxpayers, including financial institutions, certain insurance companies, recipients of Social Security and Railroad Retirement benefits, those that are deemed to incur or continue indebtedness to acquire or carry tax-exempt obligations, and individuals otherwise eligible for the earned income tax credit. Payments of interest on tax-exempt obligations, including the Bonds, are generally subject to IRS Form 1099-INT information reporting requirements. If an owner of Bonds is subject to backup withholding under those requirements, then payments of interest will also be subject to backup withholding. Those requirements do not affect the excludability of such interest from gross income for federal income tax purposes. The applicability and extent of these and other tax consequences will depend upon the particular tax status or other tax items of the owner of the Bonds. Original Bond Counsel has not expressed, nor will it express, any opinion regarding those consequences.

Prospective purchasers of the Bonds should consult their own tax advisers regarding pending or proposed federal and Kentucky tax legislation and court proceedings, and prospective purchasers of the Bonds at other than their original issuance at the price indicated on the cover of this Reoffering Circular should also consult their own tax advisers regarding other tax considerations such as the consequences of market discount, as to all of which Original Bond Counsel has not expressed, nor will it express, any opinion.

Original Bond Counsel's engagement with respect to the Bonds ended with the issuance of the Bonds, and, unless separately engaged, Original Bond Counsel is not obligated to defend the Issuer, the Company or the beneficial owners regarding the tax status of interest on the Bonds in the event of an audit examination by the IRS. The IRS has a program to audit tax exempt obligations to determine whether the interest thereon is includible in gross income for federal income tax purposes. If the IRS does audit the Bonds, under current IRS procedures, the IRS will treat the Issuer as the taxpayer and the beneficial owners of the Bonds will have only limited rights, if any, to obtain and participate in judicial review of such audit. Any action of the IRS, including but not limited to selection of the Bonds for audit, or the course or result of such audit, or an audit of other obligations presenting similar tax issues, may affect the market prices for the Bonds.

In connection with the conversion of the Bonds to the Term Rate described herein, Taft Stettinius & Hollister LLP will deliver an opinion with respect to the Bonds in accordance with the Indenture that such conversion will not adversely affect the excludability from gross income of the interest on the Bonds for federal income tax purposes. The text of such opinion has been attached hereto as Appendix E.

LEGAL MATTERS

Certain legal matters will be passed upon with respect to the conversion of the Bonds to the Term Rate described herein, by Taft Stettinius & Hollister LLP, Chicago, Illinois. Certain legal matters will be passed upon for the Company by Robert T. Lucas III, Esq., Deputy General Counsel of Duke Energy Corporation, as counsel to the Company. Certain legal matters will be passed upon for the Remarketing Agents by Ballard Spahr LLP, Philadelphia, Pennsylvania.

REMARKETING

PNC Capital Markets LLC and Truist Securities, Inc. ("*Truist*") will be appointed as remarketing agents (collectively, the "*Remarketing Agents*") for the Bonds. The Remarketing Agents will agree, subject to certain conditions, to use their best efforts to remarket such Bonds to the public at a price equal to 100% of the principal amount thereof. The Remarketing Agents will receive a fee of $187,500 from the Company for their services as Remarketing Agents and reimbursement for certain out-of-pocket expenses. The Company has agreed to indemnify the Remarketing Agents against certain liabilities, including liabilities under the federal securities laws.

In the ordinary course of their business, the Remarketing Agents and their affiliates have engaged and may engage in the future in transactions with the Company and its affiliates, including the provision of certain general financing, banking, investment banking and advisory services to the Company and its affiliates.

Truist has entered into agreements with certain of its affiliates for the retail distribution of certain municipal securities offerings, including the Bonds. Pursuant to the distribution agreements, the Remarketing Agent may share a portion of its compensation, as applicable, with respect to the Bonds with the retail affiliates. Truist and the retail affiliates are subsidiaries of Truist Financial Corporation. The principal office of Truist is Truist Securities, Inc., 3333 Peachtree Rd. NE, 11th Fl, 30326, Telephone 706-491-5946, Email: tax-exemptfinancing@truist.com

Truist Securities is the trade name for the corporate and investment banking services of Truist Financial Corporation and its subsidiaries. Securities and strategic advisory services are provided by Truist Securities, Inc., member FINRA and SIPC. Lending, financial risk management, and treasury management and payment services are offered by Truist Bank. Deposit products are offered by Truist Bank, Member FDIC.

CONTINUING DISCLOSURE

In connection with this reoffering of the Bonds, the Company will enter into a Continuing Disclosure Agreement under which the Company will undertake (the "*Undertaking*") for the benefit of the Holders and beneficial owners of the Bonds to provide certain financial information and operating data relating to the Company to the Municipal Securities Rulemaking Board (the "*MSRB*") and to provide notice to the MSRB of the occurrence of certain enumerated events, pursuant to the requirements of Section (b)(5)(i) of Securities and Exchange Commission Rule 15c2-12 (17 C.F.R. § 240.15c2-12) (the "*Rule*"). Reference is made to the Form of Continuing Disclosure Agreement for the detailed provisions thereof. See "APPENDIX C - FORM OF CONTINUING DISCLOSURE AGREEMENT."

A failure by the Company to comply with an Undertaking will not constitute an event of default under the Agreement or the Indenture, although any Holder or any beneficial owner of the Bonds may bring action to compel the Company to comply with its obligations under such Undertaking. Any such failure must be reported in accordance with the Rule and must be considered by any broker, dealer or municipal securities dealer before recommending the purchase or sale of the Bonds in the secondary market. Consequently, such a failure may adversely affect the transferability and liquidity of the Bonds and their market price.

The Issuer has no responsibility to any person with respect to the provision of such information about the Company, and, because the Bonds are special and limited obligations of the Issuer, the annual financial information and operating data of the Issuer are not material in connection with the Bonds.

RATINGS

Moody's Investors Service, Inc. ("*Moody's*") and S&P Global Ratings, a division of The McGraw-Hill Companies, Inc. ("*S&P*"), are expected to assign their ratings to each series of the Bonds of "[Baa1]" and "[BBB+]," respectively.

There is no assurance that the ratings will remain in effect for any given period of time or that they will not be revised downward or withdrawn entirely if, in the judgment of the respective rating agency, circumstances so warrant. The Remarketing Agents have not undertaken any responsibility either to bring to the attention of owners of the Bonds any proposed revision or withdrawal of the ratings or to oppose any such proposed revision or withdrawal. Any downward revision or withdrawal of the rating may have an adverse effect on the market prices of the Bonds.

MISCELLANEOUS

Appendix A to this Reoffering Circular has been furnished by the Company and incorporates by reference financial statements and other information concerning its business.

APPENDIX A

THE COMPANY

The information contained herein as Appendix A to the Reoffering Circular relates to and has been supplied by the Company. The delivery of this Reoffering Circular shall not create any implication that there has been no change in the affairs of the Company since the date hereof, or that the information contained, referred to or incorporated by reference in this Appendix A is correct as of any time subsequent to its date. The Issuer makes no representation or warranty as to the accuracy or completeness of the information contained or incorporated by reference in this Appendix A. Unless indicated otherwise, or the context otherwise requires, references in this Appendix A to "we," "us" and "our" or similar terms are to the Company.

The Company's future performance is subject to a variety of risks and uncertainties, many of which are described in the section entitled Risk Factors. If any of the risks or uncertainties materialize, the Company's business, financial condition and results of operations could be materially and adversely affected. Additional risks not presently known to the Company, or that the Company currently deems immaterial, may also impair the business, financial condition or results of operations.

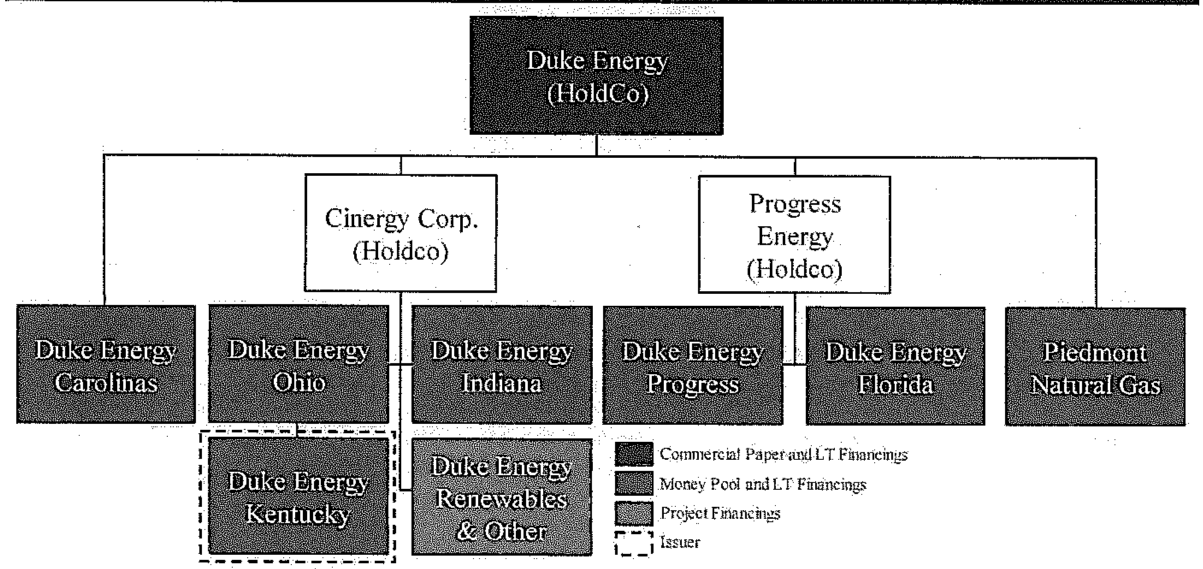
Prospective purchasers should read the information provided herein with respect to Duke Energy Kentucky, Inc. in conjunction with the more detailed information about Duke Energy Kentucky, Inc. in Duke Energy Corporation's U.S. Securities and Exchange filings and Duke Energy Kentucky, Inc.'s quarterly and annual financial statements. In considering whether to purchase the Bonds, investors should carefully consider the risks and uncertainties described above and in such filings and financial statements.

The following information is furnished solely to provide limited introductory information about the Company and does not purport to be comprehensive. Such information is qualified in their entirety by reference to detailed information and financial statements appearing in the documents referred to or incorporated herein by reference or elsewhere in this Appendix A and, therefore, such information should be read together with this Reoffering Circular. See "Financial Statements" and "Risk Factors" below.

COMPANY OVERVIEW

Duke Energy Kentucky, Inc. ("Duke Energy Kentucky" or the "*Company*") is a combination electric and gas public utility company that provides service in northern Kentucky. The Company's principal lines of business include generation, transmission and distribution of electricity as well as the sale of and/or transportation of natural gas. Duke Energy Kentucky's common stock is wholly owned by Duke Energy Ohio, Inc. (''Duke Energy Ohio''), an indirect wholly owned subsidiary of Duke Energy Corporation (collectively with its subsidiaries, "*Duke Energy*"), an energy company headquartered in Charlotte, North Carolina. Duke Energy operates primarily through its direct and indirect subsidiaries. Duke Energy's subsidiaries include Duke Energy Carolinas, LLC; Duke Energy Progress, LLC; Duke Energy Florida, LLC; Duke Energy Ohio, Inc.; Duke Energy Indiana, LLC; and Piedmont Natural Gas Company, Inc. Duke Energy Kentucky is the sole obligor on the Bonds, and neither Duke Energy nor any of its affiliates are guaranteeing Duke Energy Kentucky's obligation on the Bonds. The table below displays the simplified financing structure of Duke Energy:

DUKE ENERGY SIMPLIFIED FINANCING STRUCTURE



CUSTOMERS & SERVICE TERRITORY

Duke Energy Kentucky provides electric and gas service in the northern Kentucky area. The approximately 700 square mile service territory includes the cities of Covington and Florence, Kentucky. The Company owns an electric transmission and distribution system in Kenton, Campbell, Boone, Grant, and Pendleton counties of northern Kentucky. The Company also owns a gas distribution system, which serves either all or parts of Kenton, Campbell, Boone, Grant, Gallatin, Bracken, and Pendleton counties of northern Kentucky.

At December 31, 2021, Duke Energy Kentucky had approximately 147,000 electric customers and 102,000 gas customers. Electric sales to residential customers account for approximately 40% of electric revenue, with commercial customers at 39%, industrial at 15%, wholesale at 4% and other at 2%. Gas sales to residential and commercial customers account for approximately 65% and 28% of gas revenue, respectively, with industrial at 5% and other at 2%.

FINANCIAL STATEMENTS

The Company files certain financial statements on its website (https://www.duke-energy.com), including its annual audited financial statements for the fiscal years ended December 31, 2021 and 2020 and its unaudited financial statements for the fiscal quarter ended March 31, 2022. The audited financial statements for the fiscal years ended December 31, 2021 and 2020, together with the unaudited financial statements for the fiscal quarter ended March 31, 2022 are hereby incorporated by reference into this Reoffering Circular.

RISK FACTORS

You should carefully consider the risks described below, as well as other information contained in this Reoffering Circular, before buying any Bonds. The risks described in this section are those that the Company considers to be the most significant to your decision whether to invest in the Bonds. If any of the events described below occurs, the Company's business, financial condition or results of operations could be materially harmed. In addition, the Company may not be able to make payments on the Bonds, and this could result in your losing all or part of your investment. Furthermore, additional risks that the Company does not know about or that it currently views as immaterial may also impact the Company's business or adversely affect the Company's ability to make payments on the Bonds.

Regulatory, Legislative and Legal Risks

The Company's regulated electric and gas revenues, earnings and results are dependent on state legislation and regulation that affect electric generation, transmission, distribution and related activities and gas sales and transportation, which may limit its ability to recover costs.

The Company's regulated utility businesses are regulated on a cost-of-service/rate-of-return basis subject to the statutes of Kentucky and the rules and procedures of the Kentucky Public Service Commission ("KPSC"). If its regulated utility earnings exceed the returns established by the KPSC, the Company's retail rates may be subject to review and possible reduction by the KPSC, which may decrease the Company's future earnings. Additionally, if regulatory bodies do not allow recovery of costs incurred in providing service on a timely basis, the Company's future earnings could be negatively impacted.

If legislative and regulatory structures were to evolve in such a way that the Company's exclusive rights to serve its regulated customers were eroded, future earnings could be negatively impacted.

Deregulation or restructuring in the electric industry may result in increased competition and unrecovered costs that could adversely affect the Company's financial position, results of operations or cash flows and its utility businesses.

Increased competition resulting from deregulation or restructuring legislation could have a significant adverse impact on the Company's results of operations, financial position, or cash flows. Retail competition and the unbundling of regulated electric service could have a significant adverse financial impact on us due to an impairment of assets, a loss of retail customers, lower profit margins or increased costs of capital. The Company cannot predict the extent and timing of entry by additional competitors into the electric markets. We cannot predict if or when we will be subject to changes in legislation or regulation, nor can we predict the impact of these changes on the Company's financial position, results of operations or cash flows.

The Company's businesses are subject to extensive federal regulation that will affect its operations and costs.

The Company is subject to regulation by the Federal Energy Regulatory Commission ("*FERC*"), the U.S. Environmental Protection Agency ("*EPA*") and various other federal agencies as well as the North American Electric Reliability Corporation. Regulation affects almost every aspect of the Company's businesses, including, among other things, its ability to: take fundamental business management actions; determine the terms and rates of transmission and distribution services; make acquisitions; issue equity or debt securities; engage in transactions with other subsidiaries and affiliates; and pay dividends upstream to the Company's ultimate parent, Duke Energy. Changes to federal regulations are continuous and ongoing. There can be no assurance that laws, regulations and policies will not be changed in ways that result in material modifications of business models and objectives or affect returns on investment by restricting activities and products, subjecting the Company to escalating costs, causing delays, or prohibiting them outright.

The Company is subject to numerous environmental laws and regulations requiring significant capital expenditures that can increase the cost of operations, and which may impact or limit business plans, or cause exposure to environmental liabilities.

The Company is subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including coal combustion residuals ("*CCRs*"), air emissions, water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations can result in increased capital, operating and other costs. These laws and regulations generally require the Company to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Compliance with environmental laws and regulations can require significant expenditures, including expenditures for cleanup costs and damages arising from contaminated properties. Failure to comply with environmental regulations may result in the imposition of fines, penalties and injunctive measures affecting operating assets. The steps the Company could be required to take to ensure the Company's facilities are in compliance could be prohibitively expensive. As a result, the Company may be required to shut down or alter the operation of its facilities, which may cause it to incur losses. Further, the Company may not be successful in recovering capital and operating costs incurred to comply with new environmental regulations through existing regulatory rate structures and the Company's contracts with customers. Also, the Company may not be able to obtain or maintain from time to time all required environmental regulatory approvals for its operating assets or development projects. Delays in obtaining any required environmental regulatory approvals, failure to obtain and comply with them or changes in environmental laws or regulations to more stringent compliance levels could result in additional costs of operation for existing facilities or development of new facilities being prevented, delayed or subject to additional costs. Although it is not expected that the costs to comply with current environmental regulations will have a material adverse effect on the Company's financial position, results of operations or cash flows due to regulatory cost recovery, the Company is at risk that the costs of complying with environmental regulations in the future will have such an effect.

The EPA has enacted or proposed federal regulations governing the management of cooling water intake structures, wastewater and carbon dioxide (CO_2) emissions. These regulations may require the Company to make additional capital expenditures and increase operating and maintenance costs.

The Company's operations, capital expenditures and financial results may be affected by regulatory changes related to the impacts of global climate change.

There is continued concern, and increasing activism, both nationally and internationally, about climate change. The EPA and state regulators may adopt and implement regulations to restrict emissions of GHGs to address global climate change. Certain local and state jurisdictions can also enact laws to restrict or prevent new gas infrastructure. Increased regulation of GHG emissions could impose significant additional costs on the Company's electric and natural gas operations, their suppliers and customers and affect demand for energy conservation and renewable products, which could impact both our electric and natural gas businesses. Regulatory changes could also result in generation facilities to be retired earlier than planned to meet our net-zero 2050 goal. Though we would plan to seek cost recovery for investments related to GHG emissions reductions through regulatory rate structures, changes in the regulatory climate could result in the failure to fully recover such costs and investment in generation.

Operational Risks

The Company's operations have been and may be affected by COVID-19 in ways listed below and in ways it cannot predict at this time.

The COVID-19 pandemic has immaterially impacted and could impact the Company's business strategy, results of operations, financial position and cash flows in the future as a result of delays in rate cases or other legal proceedings, an inability to obtain labor or equipment necessary for the construction of large capital projects, an inability to procure satisfactory levels of fuels or other necessary equipment for the continued production of electricity and delivery of natural gas, and the health and availability of our critical personnel and their ability to perform business functions.

The Company's results of operations may be negatively affected by overall market, economic and other conditions that are beyond its control.

Sustained downturns or sluggishness in the economy generally affect the markets in which the Company operates and negatively influence its operations. Declines in demand for electricity and gas as a result of economic downturns in the Company's regulated service territories will reduce overall sales and lessen cash flows, especially as industrial customers reduce production and, therefore, consumption of electricity and gas. Although the Company's regulated electric and gas businesses are subject to regulated allowable rates of return and recovery of certain costs, such as fuel and gas, under periodic adjustment clauses, overall declines in electricity and gas sold as a result of economic downturn or recession could reduce revenues and cash flows, thereby diminishing results of operations. Additionally, prolonged economic downturns that negatively impact the Company's results of operations and cash flows could result in future material impairment charges to write-down the carrying value of certain assets to their respective fair values.

Factors that could impact sales volumes, generation of electricity and market prices at which the Company is able to sell electricity are as follows:

- weather conditions, including abnormally mild winter or summer weather that cause lower energy usage for heating or cooling purposes, respectively, and periods of low rainfall that decrease the ability to operate facilities in an economical manner;
- supply of and demand for energy commodities;
- availability of competitively priced alternative energy sources, which are preferred by some customers over electricity produced from coal, nuclear or gas plants, and customer usage of energy efficient equipment that reduces energy demand;
- natural gas prices;
- ability to procure satisfactory levels of inventory, such as coal and natural gas; and
- capacity and transmission service into, or out of, the Company's markets.

Natural disasters or operational accidents may adversely affect the Company's operating results.

Natural disasters or other operational accidents within the company or industry (such as forest fires, earthquakes, hurricanes, or natural gas transmission pipeline explosions) could have direct significant impacts on the Company as well as on key contractors and suppliers. Further, the generation of electricity and the transportation and storage of natural gas involve inherent operating risks that may result in accidents involving serious injury or loss of life, environmental damage, or property damage. Such events could impact the Company through changes to policies, laws and regulations whose compliance costs have a significant impact on the Company's financial position, results of operations and cash flows. In addition, if a serious operational accident were to occur, it could have a material adverse effect on the Company's results of operations, financial position, cash flows and reputation or operations.

Coal ash storage and management strategies to comply with CCR regulations could impact the Company's reputation and financial condition.

As a result of electricity produced at its coal-fired power plant, the Company manages large amounts of CCRs, typically combined with water in ash basins. The potential exists for a coal ash pond failure or coal ash related incident that could impact the environment or raise general public health concerns. Such an incident could have a material adverse impact to the Company's reputation and financial condition.

Recent regulations for the disposal of CCRs from power plants by the EPA became effective in 2015. These regulations classify CCR as nonhazardous waste under the RCRA and apply to all new and existing landfills, new and existing surface impoundments, structural fills and CCR piles and establish requirements regarding landfill design, structural integrity and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to ensure the safe disposal and management of CCR. Duke Energy Kentucky recorded an asset retirement obligation in the second quarter of 2015 as a result of such CCR regulations. In addition to federal CCR regulations, CCR landfills and surface impoundments will continue to be independently regulated by most states and additional regulations by states may be imposed in the future. These regulations may require additional capital expenditures, increased operating and maintenance costs, or closure of certain facilities which could affect the Company's financial position, results of operations and cash flows. Although the Company intends to seek cost recovery for future expenditures through the existing environmental cost recovery rider, which permits recovery of necessary and prudently incurred CCR costs, there is no guarantee that recovery of such costs will be granted.

The Company's financial position, results of operations and cash flows may be negatively affected by a lack of growth or slower growth in the number of customers, or decline in customer demand or number of customers.

Growth in customer accounts and growth of customer usage each directly influence demand for electricity and the need for additional power generation and delivery facilities. Customer growth and customer usage are affected by a number of factors outside the Company's control, such as mandated energy efficiency measures, demand-side management goals, distributed generation resources and economic and demographic conditions, such as population changes, job and income growth, housing starts, new business formation and the overall level of economic activity.

Certain regulatory and legislative bodies have introduced or are considering requirements and/or incentives to reduce energy consumption by certain dates. Additionally, technological advances driven by federal laws mandating new levels of energy efficiency in end-use electric devices or other improvements in or applications of technology could lead to declines in per capita energy consumption.

Advances in distributed generation technologies that produce power, including fuel cells, micro-turbines, wind turbines and solar cells, may reduce the cost of alternative methods of producing power to a level competitive with central power station electric production utilized by the Company.

Some or all of these factors, could result in a lack of growth or decline in customer demand for electricity or number of customers, and may cause the failure of us to fully realize anticipated benefits from significant capital investments and expenditures which could have a material adverse effect on the Company's financial position, results of operations and cash flows.

Furthermore, the Company currently has energy efficiency riders in place to recover the cost of energy efficiency programs in Kentucky. Should the Company be required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact.

The Company's future results may be impacted by changing expectations and demands including heightened emphasis on environmental, social and governance concerns.

The Company's ability to execute its strategy and achieve anticipated financial outcomes are influenced by the expectations of our customers, regulators, investors, and stakeholders. Those expectations are based in part on the core fundamentals of reliability and affordability but are also increasingly focused on the Company's ability to meet rapidly changing demands for new and varied products, services and offerings. Additionally, the risks of global climate change continues to shape its customers' sustainability goals and energy needs as well as the investment and financing criteria of investors. Failure to meet these increasing expectations or to adequately address the risks and external pressures from regulators, customers, investors and other stakeholders may impact the Company's reputation and affect its ability to achieve favorable outcomes in future rate cases and the results of operations. Additionally, with a heightened emphasis on environmental, social, and governance concerns, and climate change in particular, there is an increased risk of litigation by activists.

The Company's operating results may fluctuate on a seasonal and quarterly basis and can be negatively affected by changes in weather conditions and severe weather.

Electric power generation and the sale and transportation of natural gas are generally seasonal businesses. In most parts of the U.S. and in markets in which we operate, demand for power peaks during the warmer summer months and demand for natural gas peaks during the cold winter months, with market prices typically peaking during the warmer summer months for electricity and during the cold winter months for natural gas. Further, extreme weather conditions such as hurricanes, droughts, heat waves or, winter storms and severe weather associated with climate change could cause these seasonal fluctuations to be more pronounced. As a result, in the future, the overall operating results of the Company's businesses may fluctuate substantially on a seasonal and quarterly basis and thus make period-to-period comparison less relevant.

Sustained severe drought conditions could impact generation by the Company's fossil fuel plants, as these facilities use water for cooling purposes and for the operation of environmental compliance equipment. Furthermore, destruction caused by severe weather events, such as hurricanes, tornadoes, severe thunderstorms, snow and ice storms, can result in lost operating revenues due to outages; property damage, including downed transmission and distribution lines; and additional and unexpected expenses to mitigate storm damage. The cost of storm restoration efforts may not be fully recoverable through the regulatory process.

The Company's sales may decrease if it is unable to gain adequate, reliable and affordable access to transmission assets.

The Company depends on transmission and distribution facilities owned and operated by utilities and other energy companies to deliver electricity sold to the wholesale market. FERC's power transmission regulations require wholesale electric transmission services to be offered on an open-access, non-discriminatory basis. If transmission is disrupted, or if transmission capacity is inadequate, the Company's ability to sell and deliver products may be hindered.

The different regional power markets have changing regulatory structures, which could affect growth and performance in these regions. In addition, the independent system operators who oversee the transmission systems in regional power markets have imposed in the past, and may impose in the future, price limitations and other mechanisms to address volatility in the power markets. These types of price limitations and other mechanisms may adversely impact the profitability of the Company's wholesale power marketing business.

Fluctuations in commodity prices or availability may adversely affect various aspects of the Company's operations as well as its financial condition, results of operations and cash flows.

The Company is exposed to the effects of market fluctuations in the price of natural gas, coal, electricity and other energy-related commodities as a result of its ownership of energy-related assets. Fuel and gas costs are recovered primarily through cost-recovery clauses, subject to the approval of the KPSC. In the event of a forced outage, recovery of replacement power costs in Kentucky is limited to the cost of the unit for which a forced outage occurred. Therefore, Duke Energy Kentucky could have unrecoverable replacement power costs in the event of a forced outage.

Additionally, the Company is exposed to risk that counterparties will not be able to fulfill its obligations. Disruption in the delivery of fuel, including disruptions as a result of, among other things, transportation delays, weather, labor relations, force majeure events, or environmental regulations affecting any of these fuel suppliers, could limit the operation of the Company's facilities. Should counterparties fail to perform, the Company might be forced to replace the underlying commitment at prevailing market prices possibly resulting in unrecoverable losses in addition to the amounts, if any, already paid to the counterparties.

Certain of the Company's hedge agreements may result in the receipt of, or posting of, derivative collateral with counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to the return of collateral received and/or the posting of collateral with counterparties negatively impact liquidity. Downgrades in the Company's credit ratings could lead to additional collateral posting requirements. The Company continually monitors derivative positions in relation to market price activity.

Potential terrorist activities or military or other actions could adversely affect the Company's businesses.

The continued threat of terrorism and the impact of retaliatory military and other action by the U.S. and its allies may lead to increased political, economic and financial market instability and volatility in prices for natural gas and oil, which may have material adverse effects in ways the Company cannot predict at this time. In addition, future acts of terrorism and possible reprisals as a consequence of action by the U.S. and its allies could be directed against companies operating in the U.S. Information technology systems, transmission and distribution and generation facilities could be potential targets of terrorist activities or harmful activities by individuals or groups. The potential for terrorism has subjected the Company's operations to increased risks and could have a material adverse effect on the Company's businesses. In particular, the Company may experience increased capital and operating costs to implement increased security for its information technology systems, transmission and distribution and generation facilities. These increased costs could include additional physical plant security and security personnel or additional capability following a terrorist incident.

The failure of the Company's technology systems, or the failure to enhance existing information technology systems and implement new technology, could adversely affect the Company.

The Company's operations are dependent upon the proper functioning of its internal systems, including the information technology systems that support its underlying business processes. Any significant failure or malfunction of such information technology systems may result in disruptions of its operations. In the ordinary course of business, the Company relies on information technology systems, including the internet and third-party hosted services, to support a variety of business processes and activities and to store sensitive data, including (i) intellectual property, (ii) proprietary business information, (iii) personally identifiable information of its customers and employees, and (iv) data with respect to invoicing and the collection of payments, accounting, procurement, and supply chain activities. The

Company's information technology systems are dependent upon global communications and cloud service providers, as well as their respective vendors, many of whom have at some point experienced significant system failures and outages in the past and may experience such failures and outages in the future. These providers' systems are susceptible to cybersecurity and data breaches, outages from fire, floods, power loss, telecommunications failures, break-ins and similar events. Failure to prevent or mitigate data loss from system failures or outages could materially affect the Company's results of operations, financial position and cash flows.

In addition to maintaining its current information technology systems, the Company believes the digital transformation of the Company's business is key to driving internal efficiencies as well as providing additional capabilities to customers. The Company's information technology systems are critical to cost-effective, reliable daily operations and its ability to effectively serve its customers. The Company expects its customers to continue to demand more sophisticated technology-driven solutions and the Company must enhance or replace its information technology systems in response. This involves significant development and implementation costs to keep pace with changing technologies and customer demand. If the Company fails to successfully implement critical technology, or if it does not provide the anticipated benefits or meet customer demands, such failure could materially adversely affect its business strategy as well as impact its results of operations, financial position and cash flows.

Cyberattacks and data security breaches could adversely affect the Company's businesses.

Cybersecurity risks have generally increased in recent years as a result of the proliferation of new technologies and the increased sophistication, magnitude and frequency of cyberattacks and data security breaches. The Company relies on the continued operation of sophisticated digital information technology systems and network infrastructure, which are part of an interconnected regional grid. Additionally, connectivity to the Internet continues to increase through grid modernization and other operational excellence initiatives. Because of the critical nature of the infrastructure, increased connectivity to the Internet and technology systems' inherent vulnerability to disability or failures due to hacking, viruses, acts of war or terrorism or other types of data security breaches, the Company faces a heightened risk of cyberattack from foreign or domestic sources and have been subject, and will likely continue to be subject, to attempts to gain unauthorized access to information and/or information systems or to disrupt utility operations through computer viruses and phishing attempts either directly or indirectly through its material vendors or related third parties. In the event of a significant cybersecurity breach on either the Company or with one of its material vendors or related third parties, the Company could (i) have business operations disrupted, including the disruption of the operation of its assets and the power grid, theft of confidential company, employee, vendor or customer information, and general business systems and process interruption or compromise, including preventing the Company from servicing customers, collecting revenues or the recording, processing and/or reporting financial information correctly, (ii) experience substantial loss of revenues, repair and restoration costs, penalties and costs for lack of compliance with relevant regulations, implementation costs for additional security measures to avert future cyberattacks and other financial loss and (iii) be subject to increased regulation, litigation and reputational damage. While Duke Energy maintains insurance relating to cybersecurity events, such insurance is subject to a number of exclusions and may be insufficient to offset any losses, costs or damage experienced. Also, the market for cybersecurity insurance is relatively new and coverage available for cybersecurity events may evolve as the industry matures.

The Company is subject to standards enacted by the North American Electric Reliability Corporation and enforced by FERC regarding protection of the physical and cyber security of critical infrastructure assets required for operating North America's bulk electric system. While the Company believes it is in compliance with such standards and regulations, it may in the future be, found to be in violation of such standards and regulations. In addition, compliance with or changes in the applicable standards and regulations may subject the Company to higher operating costs and/or increased capital expenditures as well as substantial fines for non-compliance.

Failure to attract and retain an appropriately qualified workforce could unfavorably impact the Company's results of operations.

Certain events, such as an aging workforce, mismatch of skill set or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges include lack of resources, loss of knowledge base and the lengthy time required for skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to new employees, or future availability and cost of contract labor may adversely affect the ability to manage and operate the business. If we are unable to successfully attract and retain an appropriately qualified workforce, the Company's financial position or results of operations could be negatively affected.

The Company's membership in a Regional Transmission Organization (an "RTO") presents risks that could have a material adverse effect on its results of operations, financial condition and cash flows.

The rules governing the various regional power markets may change, which could affect the Company's costs and/or revenues. To the degree the Company incurs significant additional fees and increased costs to participate in an RTO, its results of operations may be impacted. The Company may be allocated a portion of the cost of transmission facilities built by others due to changes in RTO transmission rate design. The Company may be required to expand its transmission system according to decisions made by an RTO rather than its own internal planning process. In addition, RTOs have been developing rules associated with the allocation and methodology of assigning costs associated with improved transmission reliability, reduced transmission congestion and firm transmission rights that may have a financial impact on the Company.

As a member of an RTO, the Company is subject to certain additional risks, including those associated with the allocation among RTO members, of losses caused by unreimbursed defaults of other participants in the RTO markets and those associated with complaint cases filed against an RTO that may seek refunds of revenues previously earned by RTO members.

Capital expenditure costs could materially differ from those projected

Construction risks associated with the completion of the Company's capital investment projects, including risks related to obtaining and complying with terms of permits, meeting construction budgets and schedules, and satisfying operating and environmental performance standards could cause costs to differ materially from those projected.

Liquidity and Capital Requirements Risks

The Company relies on access to short-term borrowings and longer-term capital markets to finance its capital requirements and support its liquidity needs. Access to those markets can be adversely affected by a number of conditions, many of which are beyond the Company's control.

The Company's businesses are financed to a large degree through debt. The maturity and repayment profile of debt used to finance investments often does not correlate to cash flows from the Company's assets. Accordingly, as a source of liquidity for capital requirements not satisfied by the cash flow from its operations and to fund investments originally financed through debt instruments with disparate maturities, the Company relies on access to short-term money markets as well as longer-term capital markets. The Company also relies on access to short-term intercompany borrowings. If the Company is not able to access capital at competitive rates or at all, the ability to finance its operations and implement its strategy and business plan as scheduled could be adversely affected. An inability to access capital may limit the Company's ability to pursue improvements or acquisitions that may otherwise rely on for future growth.

Market disruptions may increase the cost of borrowing or adversely affect the ability to access one or more financial markets. Such disruptions could include: economic downturns, the bankruptcy of an unrelated energy company, unfavorable capital market conditions, market prices for electricity and gas, actual or threatened terrorist attacks, or the overall health of the energy industry. The availability of credit under Duke Energy's Master Credit Facility depends upon the ability of the banks providing commitments under the facility to provide funds when the Company's obligations to do so arise. Systematic risk of the banking system and the financial markets could prevent a bank from meeting its obligations under the facility agreement.

Duke Energy maintains a revolving credit facility to provide backup for its commercial paper program and letters of credit to support variable rate demand tax-exempt bonds that may be put to its affiliate issuers (including Duke Energy Kentucky) at the option of the holder. The facility includes a borrowing sublimit for Duke Energy Kentucky, and financial covenants that limit the amount of debt that can be outstanding as a percentage of the total capital for the specific entity. Failure to maintain these covenants could preclude the Company from having letters of credit issued on the Company's behalf or from making borrowings under the Master Credit Facility.

The Company must meet credit quality standards and there is no assurance we will maintain investment grade credit ratings.

The Company's senior long-term debt is currently rated investment grade by various rating agencies. The Company cannot ensure its senior long-term debt will be rated investment grade in the future.

If the rating agencies were to rate the Company below investment grade, borrowing costs would increase, perhaps significantly. In addition, the potential pool of investors and funding sources would likely decrease. Further, if short-term debt ratings were to fall, access to the commercial paper market could by significantly limited. Any downgrade or other event negatively affecting the Company's credit ratings could also increase Duke Energy's need to provide liquidity in the form of capital contributions or loans, thus reducing the liquidity and borrowing availability of the Duke Energy consolidated group. A downgrade below investment grade could also require the posting of additional collateral in the form of letters of credit or cash under various credit, commodity, and capacity agreements and trigger termination clauses in some interest rate derivative agreements, which could require cash payments. These events would likely reduce the Company's liquidity and profitability and could have a material effect on the Company's financial position, results of operations or cash flows.

Non-compliance with debt covenants or conditions could adversely affect the Company's ability to execute future borrowings.

The Company's debt and credit agreements contain various financial and other covenants. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements.

Poor investment performance of the Duke Energy pension plan holdings and other factors impacting pension plan costs could unfavorably impact the Company's liquidity and results of operations.

The costs of providing non-contributory defined benefit pension plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plans, future government regulation and required or voluntary contributions made to the plans. Duke Energy Kentucky is allocated a proportionate share of the cost and obligations related to these plans. Without sustained growth in the pension investments over time to increase the value of plan assets and, depending upon the other factors impacting costs as listed above, Duke Energy could be required to fund its plans with significant amounts of cash. Such cash funding obligations, and the Company's proportionate share of such cash funding obligations, could have a material impact on the Company's financial position, results of operations or cash flows.

Risk Factors Relating to the Bonds

The Company's ability to satisfy the Company's obligations with respect to the Bonds will depend or its future operating performance, results of operations, cash flows and financial position.

The Company's future operating performance, results of operations, cash flows and financial position are subject, in part, to factors beyond its control, including interest rates, commodity prices, general economic conditions and financial and business conditions. If the Company is unable to generate sufficient operating cash flows to service its debt, including the Bonds, it may be required to obtain additional financing or take other actions to generate sufficient funds, which could have a material adverse effect on its financial position, results of operations or cash flows.

The Bonds could be impacted by various transactions.

The indenture under which the Bonds will be issued does not prohibit the Company from entering into various transactions, including acquisitions, change of control transactions, refinancings, recapitalizations or other highly leveraged transactions that could increase the amount of the Company's outstanding indebtedness, or adversely affect its capital structure or credit ratings, or otherwise adversely affect holders of the Bonds. As a result, the Company may enter into a transaction even though the transaction could increase the total amount of outstanding indebtedness, adversely affect its capital structure or credit ratings or otherwise adversely affect the holders of the Bonds.

Sales or other transfers of the Bonds are regulated by federal securities law.

The Bonds are being offered and sold pursuant to an exemption from registration under federal and applicable state securities laws. Therefore, you may transfer or resell the Bonds in the United States only in a transaction registered under, or exempt from the registration requirements of, federal and applicable state securities laws.

APPENDIX B

CERTAIN DEFINITIONS

Unless the context otherwise requires, as used herein the following terms will, have the following meanings.

"Authorized Denominations" means denominations of $5,000 and integral multiples thereof.

"Book-Entry System" means the system maintained by the Depository and described herein under "THE BONDS – Book-Entry-Only System."

"Business Day" means any day other than (i) a Saturday or Sunday, (ii) a day on which commercial banks in New York, New York, or the city or cities in which are located the corporate trust office or payment office of the Trustee, the Company, the Remarketing Agents, the Registrar or the Paying Agent are authorized by law to close or (iii) a day on which the New York Stock Exchange is closed.

"Code" means the Internal Revenue Code of 1986, as amended from time to time. References to the Code and Sections of the Code include relevant applicable regulations and proposed regulations thereunder and under the Internal Revenue Code of 1954, as amended, and any successor provisions to those Sections, regulations or proposed regulations and, in addition, all revenue rulings, announcements, notices, procedures and judicial determinations under the foregoing applicable to the Bonds.

"Depository" means The Depository Trust Company (a limited purpose trust company), New York, New York, until a successor Depository will have become such pursuant to the applicable provisions of the Indenture and thereafter, "Depository" will mean the successor Depository. Any Depository will be a securities depository that is a clearing agency under federal law operating and maintaining, with its participants or otherwise, a Book Entry System to record ownership of beneficial interests in Bonds or bond service charges thereon, and to effect transfers of beneficial interests in the Bonds, in a Book Entry Form.

"Government Obligations" means obligations of, or obligations guaranteed as to principal and interest by, the U.S. or any agency or instrumentality thereof, when such obligations are backed by the full faith and credit of the U.S. including:

- U.S. treasury obligations
- All direct or fully guaranteed obligations
- Farmers Home Administration
- General Services Administration
- Guaranteed Title XI financing
- Government National Mortgage Association (GNMA)
- State and Local Government Series

"Interest Payment Date" means each December 1 and June 1, commencing December 1, 2022.

"Maturity Date" means August 1, 2027.

"Moody's" means Moody's Investors Service, Inc., a corporation organized and existing under the laws of the State of Delaware, its successors and assigns, and, if such corporation is dissolved or liquidated or no longer performs the functions of a securities rating agency, "Moody's" will be deemed to refer to any other nationally recognized securities rating agency designated by the Issuer, with the approval of the Company, by notice to the Trustee and the Company.

"Opinion of Bond Counsel" means a written opinion of nationally-recognized bond counsel selected by the Company and acceptable to the Trustee and who is experienced in matters relating to the exclusion from gross income for federal income tax purposes of interest on obligations issued by states and their political subdivisions. Bond Counsel may be counsel to the Trustee or the Company.

"Outstanding Bonds," "Bonds outstanding" or *"outstanding"* as applied to Bonds, means, as of the applicable date, all Bonds which have been authenticated and delivered, or which are being delivered by the Trustee under the Indenture, except:

(a) Bonds cancelled upon surrender, exchange or transfer, or cancelled because of payment or redemption on or prior to that date;

(b) On or after any purchase date for Bonds pursuant to the Indenture, all Bonds (or portions of Bonds) which are tendered or deemed to have been tendered for purchase on such date, but which have not been delivered to the Paying Agent, provided that funds sufficient for such purchase are on deposit with the Paying Agent in the appropriate accounts in accordance with the provisions hereof;

(c) Bonds, or the portion thereof, for the payment, redemption or purchase for cancellation of which sufficient moneys have been deposited and credited with the Trustee or Paying Agent to the appropriate accounts on or prior to that date for the purpose (whether upon or prior to the maturity or redemption date of those Bonds); provided, that if any of those Bonds are to be redeemed prior to their maturity, notice of that redemption has been given or arrangements satisfactory to the Trustee have been made for giving notice of that redemption, or waiver by the affected Holders of that notice satisfactory in form to the Trustee has been filed with the Trustee;

(d) Bonds, or the portion thereof, which are deemed to have been paid and discharged or caused to have been paid and discharged pursuant to the provisions of the Indenture; and

(e) Bonds in lieu of which others have been authenticated under the Indenture; provided, however, that in determining whether the Holders of the requisite principal amount of Outstanding Bonds have given any request, demand, authorization, direction, notice, consent or waiver under the Indenture, Bonds owned by the Company or an affiliate thereof will be disregarded and deemed not to be Outstanding, except that in determining whether the Trustee will be protected in relying upon any such request, demand, authorization, direction, notice, consent or waiver, only Bonds which the Trustee knows to be so owned will be disregarded unless all Bonds are owned by the Company or any affiliate thereof and/or held by the Trustee for the account of the Company and/or an affiliate thereof, in which case such Bonds will be considered outstanding for the purpose of such determination.

"Paying Agent" means (i) Deutsche Bank National Trust Company, with a corporate trust office in Chicago, Illinois, or (ii) any bank or trust company designated as Paying Agent by or in accordance with the Indenture.

"Prior Bonds" means those bonds identified under "APPLICATION OF PROCEEDS."

"Registrar" means Deutsche Bank National Trust Company, until a successor Registrar has become such pursuant to the Indenture.

"Regular Record Date" means the close of business on the fifteenth day of the month preceding each Interest Payment Date.

"*S&P*" means S&P Global Ratings, and its successors and assigns, except that if such Division is dissolved or liquidated or no longer performs the functions of a securities rating agency, "S&P" will be deemed to refer to any other nationally recognized securities rating organization designated by the Issuer, with the approval of the Company, by notice to the Trustee and the Company.

"State" means the Commonwealth of Kentucky.

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APPENDIX C

FORM OF CONTINUING DISCLOSURE AGREEMENT

This CONTINUING DISCLOSURE UNDERTAKING, dated _______, 2022 (this "Agreement"), between Duke Energy Kentucky, Inc., a Kentucky corporation (the "Company") and Deutsche Bank National Trust Company, as trustee (the "Trustee"), is executed and delivered in connection with the remarketing of the County of Boone, Kentucky (the "Issuer") $50,000,000 County of Boone, Kentucky Pollution Control Revenue Refunding Bonds, Series 2008A (Duke Energy Kentucky, Inc. Project) (the "Bonds"). The Bonds were previously issued pursuant to a Trust Indenture, dated as of December 1, 2008 (the "Original Indenture"), between the Issuer and Deutsche Bank National Trust Company, as trustee (the "Trustee"). The Original Indenture was supplemented and amended by a First Supplemental Trust Indenture, dated December 1, 2011 (the "First Supplemental Indenture" and together with the Original Indenture, the "Indenture"), between the Issuer and the Trustee.

The Company and the Trustee covenant and agree as follows for the benefit of the Owners (as defined below) and the Participating Underwriter (as defined below):

Section 1. Definitions. In addition to the definitions set forth in the Indenture, which apply to any capitalized term used in this Agreement and not otherwise defined in this Section 1, the following capitalized terms shall have the meanings indicated below. Other capitalized terms shall have the same meanings as defined in the Indenture.

"Annual Report" shall mean the information described in Section 3(a) hereof or a Form 10-K (as defined in Section 3(b) hereof).

"Commission" shall mean the Securities and Exchange Commission, or any successor body thereto.

"Exchange Act" shall mean the Securities Exchange Act of 1934, as the same may be amended from time to time.

"Financial Obligation" shall mean a: (a) debt obligation; (b) derivative instrument entered into in connection with, or pledged as security or a source of payment for, an existing or planned debt obligation; or (c) guarantee of (a) or (b). The term "financial obligation" shall not include municipal securities as to which a final official statement has been provided to the MSRB consistent with the Rule.

"Listed Events" shall mean any of the events listed in Section 5 of this Agreement.

"MSRB" means the Municipal Securities Rulemaking Board established pursuant to the provisions of Section 15B(b)(1) of the Exchange Act, as amended, or any successor thereto or to the functions of the MSRB contemplated by this agreement.

"Owner" of the Bonds shall mean any registered owner of the Bonds or any person which (i) has or shares the power, directly or indirectly, to vote or consent with respect to, or to dispose of ownership of, any of the Bonds (including persons holding through any nominee, securities depository or other intermediary) or (ii) is treated as the owner of any of the Bonds for federal income tax purposes.

"Participating Underwriter" shall mean collectively, PNC Capital Markets LLC and Truist Securities, Inc.

"Quarterly Report" shall mean the information described in Section 3(c) hereof or a Form 10-Q (as defined in Section 3(d) hereof).

"Rule" shall mean Rule 15c2-12 adopted by the Commission under the Securities Exchange Act of 1934 (the Exchange Act"), as the same may be amended from time to time.

Section 2. Purpose of the Disclosure Agreement. This Agreement is being executed and delivered by the Company and the Trustee for the benefit of the Owners and in order to assist the Participating Underwriter in complying with the Rule. The Company acknowledges that the Participating Underwriter, the Issuer and the Trustee have undertaken no responsibility with respect to any reports, notices or disclosures provided or required under this Agreement, and have no liability to any person, including any Owners, with respect to any such reports, notices or disclosures.

Section 3. Provision of Financial Information.

(a) With respect to the Company's fiscal years ending December 31, 2022 and thereafter, if a Form 10-K (as defined below) is not filed with the Commission, the Company shall provide to the MSRB audited financial statements prepared in accordance with generally accepted accounting principles (GAAP) of the type incorporated by reference in the Reoffering Circular dated June __, 2022, delivered with respect to the reoffering of the Bonds, not later than one hundred twenty (120) days after the end of the Company's fiscal year.

(b) If the Company shall file with the Commission, with respect to the Company's fiscal years ending December 31, 2022 and thereafter, reports on Form 10-K under Sections 13 or 15(d) of the Exchange Act, including any successor provisions thereto (the "Form 10-K"), then the Company shall provide to the MSRB (i) a copy of such Form 10-K or (ii) notice on an annual basis that the Form 10-K constitutes the annual financial information with respect to the Company required under the Rule, not later than one hundred twenty (120) days after the end of the Company's fiscal year.

(c) With respect to the Company's fiscal quarters ending December 31, 2022 and thereafter, if a Form 10-Q (as defined below) is not filed with the Commission, the Company shall provide to the MSRB unaudited financial statements prepared in accordance with generally accepted accounting principles (GAAP) of the type incorporated by reference in the Reoffering Circular dated June __, 2022, delivered with respect to the reoffering of the Bonds, not later than forty-five (45) days after the end of the Company's fiscal quarter.

(d) If the Company shall file with the Commission, with respect to the Company's fiscal quarters ending December 31, 2022 and thereafter, reports on Form 10-Q under Sections 13 or 15(d) of the Exchange Act, including any successor provisions thereto (the "Form 10-Q"), then the Company shall provide to the MSRB (i) a copy of such Form 10-Q or (ii) notice on a quarterly basis that the Form 10-Q constitutes the quarterly financial information with respect to the Company required under the Rule, not later than forty-five (45) days after the end of the Company's fiscal quarter.

(e) The Company shall, in a timely manner, provide to the MSRB notice of failure by the Company to file any Annual Report or Quarterly Report by the date due.

Section 4. Reporting of Significant Events. The Company shall provide in a timely manner not in excess of ten (10) business days after the occurrence of the event, to the MSRB notice of the occurrence of any of the following events with respect to the Bonds:

(a) principal and interest payment delinquencies;

(b) non-payment related defaults, if material;

(c) any unscheduled draws on debt service reserves reflecting financial difficulties;

(d) unscheduled draws on credit enhancements facilities reflecting financial difficulties;

(e) substitution of credit or liquidity providers, or their failure to perform;

(f) adverse tax opinions, the issuance by the Internal Revenue Service of proposed or final determinations of taxability, Notices of Proposed Issue (IRS Form 5701-TEB) or other material notices or determinations with respect to the tax status of the Bonds, or other material events affecting the tax status of the Bonds;

(g) modifications to rights of the holders of the Bonds, if material;

(h) Bond calls, if material, and tender offers;

(i) defeasances;

(j) release, substitution or sale of property securing repayment of the Bonds, if material;

(k) rating changes of the Bonds or the Company;

(l) bankruptcy, insolvency, receivership or similar event of the Company. For purposes of this Section 5(l), any such event shall be considered to have occurred when any of the following occur: the appointment of a receiver, fiscal agent or similar officer for the Company in a proceeding under the U.S. Bankruptcy Code or in any other proceeding under state or federal law in which a court or governmental authority has assumed jurisdiction over substantially all of the assets or business of the Company, or if such jurisdiction has been assumed by leaving the existing governing body and officials or officers in possession but subject to the supervision and orders of a court or governmental authority, or the entry of an order confirming a plan of reorganization, arrangement or liquidation by a court or governmental authority having supervision or jurisdiction over substantially all of the assets or business of the Company;

(m) the consummation of a merger, consolidation, or acquisition involving the Company or the sale of all or substantially all of the assets of the Company, other than in the ordinary course of business, the entry into a definitive agreement to undertake such an action or the termination of a definitive agreement relating to any such actions, other than pursuant to its terms, if material;

(n) appointment of a successor or additional trustee or the change of name of a trustee, if material;

(o) incurrence of a Financial Obligation of the Company, if material, or agreement to covenants, events of default, remedies, priority rights, or other similar terms of a Financial Obligation of the Company, any of which affect Bond holders, if material; and

(p) default, event of acceleration, termination event, modification of terms, or other similar events under the terms of a Financial Obligation of the Company, any of which reflect financial difficulties.

Section 5. Failure to Provide Required Notices. In a timely manner, the Company shall give to the Issuer, the Trustee and the MSRB notice of any failure by the Company to provide any information required pursuant to Section 4 or Section 4 above within the time limits specified in each such Section.

Section 6. Reports to Trustee. The Company shall send to the Trustee copies of any information delivered to the MSRB pursuant to Section 3 and Section 4 above; and concurrently with the delivery of such information, a certificate signed by an authorized representative of the Company stating that such information has been delivered pursuant to this Agreement and the date on which such information was delivered; provided, however, that no information required by Section 3 or certificate related thereto shall be required to be delivered to the Trustee if such information is available on the Company's website, http://www.duke-energy.com.

The Trustee shall keep any information or certificate delivered pursuant to this Section 6, and such items shall be open to inspection by the Issuer and by any Holder at any reasonable time during regular business hours on reasonable notice. The Trustee shall not be required to deliver any such information or certificate to any Holder or to any other person. If the Trustee receives a request for an interpretation or opinion, it may refer such request to the Company for response.

Section 7. Submission of Documents to the MSRB. Unless otherwise required by law, all documents provided to the MSRB in compliance with Sections 3 and 4 shall be provided by the Company to the MSRB in an electronic format and shall be accompanied by identifying information, in each case as prescribed by the MSRB. As of the date of this Agreement, the MSRB has established its Electronic Municipal Market Access System ("EMMA") as its continuing disclosure service for purposes of the Rule, and unless and until otherwise prescribed by the MSRB, all documents provided to the MSRB in compliance with Section 3 and Section 4 shall be submitted through EMMA in the format prescribed by the MSRB.

Section 8. Termination of Agreement. The Company's obligations under this Agreement shall terminate upon the defeasance, prior redemption or payment in full of all of the Bonds. If the Company's obligations under the Loan Agreement are assumed in full by another obligated person, such person shall be responsible for compliance with this Agreement in the same manner as if it were the Company, and the Company shall have no further responsibility hereunder. The Company shall notify the MSRB that the Company's obligations under this Agreement have terminated.

Section 9. Amendment. Notwithstanding any other provision of this Agreement, the Company and the Trustee may amend this Agreement, and any provision of this Agreement may be waived, provided that the following conditions are satisfied:

(a) If the amendment or waiver relates to the provisions of Section 3, Section 4 or Section 5, it may only be made in connection with a change in circumstances that arises from a change in legal requirements, change in law, or change in the identity, nature or status of an obligated person with respect to the Bonds, or the type of business conducted;

(b) This Agreement, as amended or taking into account such waiver, would, in the opinion of Bond Counsel, have complied with the requirements of the Rule at the time of the original issuance of the Bonds, after taking into account any amendments or interpretations of the Rule, as well as any change in circumstances; and

(c) The amendment or waiver either (i) is approved by the Owners in the same manner as provided in the Indenture for amendments to the Indenture with the consent of Owners, or (ii) does not, in the opinion of nationally recognized bond counsel, materially impair the interests of the Owners.

Section 10. Additional Information. Nothing in this Agreement shall be deemed to prevent the Company from disseminating any other information, using the means of dissemination set forth in this Agreement or any other means of communication, or including any other information in any Annual Report or notice of occurrence of a Listed Event, in addition to that which is required by this Agreement. If the Company chooses to include any information in any Annual Report or notice of occurrence of a Listed Event, in addition to that which is specifically required by this Agreement, the Company shall have no obligation under this Agreement to update such information or to include it in any future Annual Report or notice of occurrence of a Listed Event.

Section 11. Default. In the event of a failure of the Company to comply with any provision of this Agreement, the Trustee may (but shall not be obligated) or any Holder may take such actions as may be necessary and appropriate, including seeking specific performance by court order, to cause the Company to comply with its obligations under this Agreement. A default under this Agreement shall not be deemed an Event of Default under the Indenture or the Loan Agreement, and the sole remedy under this Agreement in the event of any failure of any party to comply with this Agreement shall be an action to compel performance. The Trustee shall have no responsibility or liability with respect to the Company's failure to comply with its obligations under this Agreement, and shall not be required to compel the Company to so comply.

Section 12. Indemnification and Expenses. The Company shall compensate, reimburse, indemnify and hold harmless the Trustee for all costs, charges, losses, claims, liabilities and expenses incurred by the Trustee and its offices, directors, employees and agents in connection with the execution, delivery and performance of this Agreement to the same extent as is provided in the Indenture and in the Loan Agreement.

Section 13. Beneficiaries. This Agreement shall inure solely to the benefit of the Issuer, the Trustee, the Participating Underwriter and the Owners, and shall create no rights in any other person or entity.

Section 14. Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the Commonwealth of Kentucky.

Section 15. Counterparts. This Agreement may be executed in several counterparts, each of which shall be an original and all of which shall constitute but one and the same instrument. A signed copy of this Agreement transmitted by facsimile, email or other means of electronic transmission shall be deemed to have the same legal effect as delivery of an original executed copy of this Agreement for all purposes.

Section 16. Severability. In case any one or more of the provisions of this Agreement shall for any reason be held to be illegal or invalid, such illegality or invalidity shall not affect any other provision of this Agreement, but this Agreement shall be construed and enforced as if such illegal or invalid provision had not been contained herein.

Section 17. Electronic Signatures. The parties agree that the electronic signature of a party to this Agreement shall be as valid as an original signature of such party and shall be effective to bind such party to this Agreement. For purposes hereof: (i) "electronic signature" means a manually signed original signature that is then transmitted by electronic means; and (ii) "transmitted by electronic means" means sent in the form of a facsimile or sent via the internet as a portable document format ("pdf") or other replicating image attached to an electronic mail or internet message.

[Signatures on following page]

IN WITNESS WHEREOF, the Trustee and the Company have caused this Agreement to be executed by a duly authorized officer or employee, all as of the day and year first above written.

DUKE ENERGY KENTUCKY, INC.

By:______________________________
Name:
Title:

DEUTSCHE BANK NATIONAL TRUST COMPANY, as Trustee

By:______________________________
Name:
Title:

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APPENDIX D

[TEXT OF ORIGINAL BOND COUNSEL OPINION]

December __, 2008

County of Boone, Kentucky
Burlington, Kentucky

Duke Energy Kentucky, Inc.
Charlotte, North Carolina

Deutsche Bank National Trust Company
Chicago, Illinois

Wachovia Bank, National Association
Charlotte, North Carolina

Re: $50,000,000 principal amount of County of Boone, Kentucky Pollution Control Revenue Refunding Bonds, Series 2008A (Duke Energy Kentucky, Inc. Project)

Ladies and Gentlemen:

We have acted as bond counsel in connection with the issuance by the County of Boone, Kentucky (the "Issuer") of its Pollution Control Revenue Refunding Bonds, Series 2008A (Duke Energy Kentucky, Inc. Project), in an aggregate principal amount of $50,000,000 (the "Bonds"). The Bonds are being issued pursuant to Sections 103.200 to 103.286, inclusive, of the Kentucky Revised Statutes (the "Act"), an ordinance adopted by the Issuer on April 8, 2008 (the "Ordinance"), and under and pursuant to a Trust Indenture (the "Indenture") dated as of December 1, 2008, between the Issuer and Deutsche Bank National Trust Company, as trustee (the "Trustee"). In such capacity we have examined (a) a certified transcript containing the proceedings of the Issuer relating to the authorization, issuance and sale of the Bonds, the Loan Agreement (the "Agreement") dated as of December 1, 2008, between the Issuer and Duke Energy Kentucky, Inc., a Kentucky corporation (the "Company"), the Bond Purchase Agreement dated December ___, 2008 (the "Bond Purchase Agreement") between the Issuer and Wachovia Bank, National Association (the "Underwriter"); and the Official Statement relating to the Bonds dated December 3, 2008; (b) the Tax Certificate of the Issuer dated the date hereof; (c) the Tax Certificate of the Company dated the date hereof; (d) executed counterparts of the Indenture and the Agreement; (e) the executed and authenticated Bonds; (f) the opinions of Robert T. Lucas III, Associate General Counsel, and Richard G. Beach, Esq., Assistant General Counsel, as counsel for the Company; and (g) an opinion of Robert D. Neace, the Boone County Attorney, as counsel for the Issuer.

As to questions of fact material to our opinion, we have relied, without undertaking to verify the same by independent investigation, upon representations, covenants and certifications of public officials,

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the Company and others contained in the documents, instruments and certified proceedings described in the first paragraph of this opinion, including without limitation, the covenants and representations of the Issuer and the Company regarding compliance and continuing compliance with certain requirements and conditions imposed by the Internal Revenue Code of 1986, as amended (the "Code") with respect to the exclusion of interest on the Bonds pursuant to Section 103 of the Code from gross income for purposes of Federal income taxation (the "Tax Covenants").

Based upon the foregoing and our review of such other information, papers and documents as we believed necessary or advisable, we are of the opinion that:

1. The Issuer has full legal right, power and authority under the Constitution and laws of the Commonwealth of Kentucky, including the Act, to adopt the Ordinance, to issue, sell and deliver the Bonds and to enter into and perform its obligations under the Indenture and the Agreement.

2. The Indenture and Agreement have each been duly authorized, executed and delivered by the Issuer and constitute the legal, valid and binding obligations of the Issuer enforceable against the Issuer in accordance with their terms.

3. The Bonds have been duly authorized, executed, authenticated, issued and delivered and are legal, valid and binding in accordance with the terms thereof. The Bonds constitute special and limited obligations of the Issuer, and the principal of and interest on the Bonds (collectively, "Debt Service") are payable solely from the revenues and other moneys assigned by the Indenture to secure such payment. Those revenues and other moneys include the payments required to be made by the Company under the Agreement. The Bonds do not constitute a debt or pledge of the faith and credit or taxing power of the Issuer, or the Commonwealth of Kentucky or any political subdivision thereof, and the holders or owners thereof have no right to have taxes levied by the Commonwealth of Kentucky or the Issuer for the payment of Debt Service on the Bonds.

4. Under existing federal statutes, decisions, regulations and rulings, the interest on the Bonds is excludable from gross income of the owners for federal income tax purposes pursuant to Section 103 of the Code, except for interest on any Bond for any period during which such Bond is held by a person who is a substantial user of the Project or a related person thereto within the meaning of Section 147(a) of the Code and the regulations promulgated pursuant thereto, and subject to continued compliance with the Tax Covenants. The interest on the Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, but the interest on the Bonds is included in adjusted current earnings in calculating corporate alternative minimum taxable income for purposes of the corporate alternative minimum tax. We express no opinion herein as to any other federal tax consequences of acquiring carrying, owning or disposing of the Bonds.

5. Under statutes, decisions, regulations and rulings existing on this date, the interest on the Bonds is exempt from income taxation in the Commonwealth of Kentucky. This opinion relates only to the tax exemption of interest from Kentucky income taxes.

We do not express any opinion herein as to the adequacy or accuracy of the Official Statement of the Issuer, dated December 3, 2008, pertaining to the offering of the Bonds.

It is to be understood that the rights of the owners of the Bonds, as well as the rights of the Issuer, the Trustee and the Underwriter, and the enforceability of the Bonds, the Agreement, the Indenture and the Bond Purchase Agreement may be subject to bankruptcy, insolvency, reorganization, moratorium and other similar laws affecting creditors' rights heretofore or hereafter enacted and that the enforcement of the Bonds, the Agreement, the Indenture and the Bond Purchase Agreement may be subject to the exercise of judicial discretion in accordance with general principles of equity. It is to be further understood that the rights of the owners of the Bonds, as well as the rights of the Issuer, the Trustee and the Underwriter, and the enforceability of the Bonds, the Agreement, the Indenture and the Bond Purchase Agreement may be subject to the valid exercise of the constitutional powers of the Commonwealth of Kentucky and the United States of America.

Sincerely,

FROST BROWN TODD LLC

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APPENDIX E
FORM OF NO ADVERSE TAX OPINION

June _____, 2022

County of Boone County, Kentucky
Burlington, Kentucky

Deutsche Bank National Trust Company, as Trustee and Paying Agent
Chicago, Illinois

Duke Energy Kentucky, Inc.
Charlotte, North Carolina

PNC Capital Markets LLC
Philadelphia, Pennsylvania

Truist Securities, Inc.
Atlanta, Georgia

This opinion is rendered at the request of Duke Energy Kentucky, Inc. (the "Company") in connection with the adjustment of the interest rate on the Bonds (identified below) from the LIBOR Rate to a Term Rate to be effective on June __, 2022 and a change in the Remarketing Agent for the Bonds (collectively, the "Actions"). The Bonds are the $50,000,000 County of Boone, Kentucky Pollution Control Revenue Refunding Bonds, Series 2008A (Duke Energy Kentucky, Inc. Project) (the "Bonds"). The Bonds were issued pursuant to a Trust Indenture dated as of December 1, 2008 between the County of Boone, Kentucky (the "Issuer") and Deutsche Bank National Trust Company, as trustee (the "Trustee"), as amended by a First Supplemental Trust Indenture, dated December 1, 2011, between the Issuer and the Trustee and a Second Supplemental Trust Indenture, dated November 4, 2016, between the Issuer and the Trustee (collectively, the "Indenture"). Capitalized terms not otherwise defined in this opinion are used as defined in the Indenture.

With your Company's permission, we have assumed that the Actions will not result in a substantial enhancement or impairment of the Company's capacity to meet its obligation to make payments under the Agreement so that there will be no change in payment expectations with respect to the Bonds.

In our capacity as bond counsel, we have examined such proceedings, documents, matters and law as we deem necessary to render the opinions set forth in this letter.

Based on that examination and subject to the limitations stated below, we are of the opinion that under existing law:

(1) The Actions are authorized and permitted by the Indenture and the laws of the State (including the Act); and

(2) The Actions will not, in and of themselves, adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes.

The opinions stated above are based on an analysis of existing laws, regulations, rulings and court decisions and cover certain matters not directly addressed by such authorities. In rendering all such opinions we assume, without independent verification, and rely upon the accuracy of the factual matters represented, warranted or certified in the proceedings and documents we have examined.

The opinion stated above regarding treatment of interest on the Bonds for federal income tax purposes is limited to the legal effect of the Actions. Frost Brown Todd LLC delivered its opinion letter as bond counsel to the Issuer dated December 1, 2008 (the "Original Bond Opinion") in connection with the original issuance of the Bonds. In connection with certain matters related to the Bonds on December 1, 2011 and November 4, 2016 we delivered our opinions (collectively, the "Supplemental Bond Opinions"). The Original Bond Opinion and the Supplemental Bond Opinions speak only as of their respective dates and this letter is not a confirmation or renewal of the Original Bond Opinion or the Supplemental Bond Opinions as of any more recent date. We have not for purposes of this letter examined any of the matters of law or fact upon which the legal opinions expressed in the Original Bond Opinion or the Supplemental Bond Opinions were based. We have not for purposes of this letter obtained, verified or reviewed any information concerning any event other than the Actions that might have occurred subsequent to the original issuance of the Bonds and that might have adversely affected the exclusion from gross income of interest on the Bonds for federal income tax purposes. Accordingly, except as expressly stated above, we express no opinion as to any matters concerning the status of the interest on the Bonds under the Internal Revenue Code of 1986, as amended, including specifically whether the interest on the Bonds is excluded from gross income for federal income tax purposes.

This letter is being furnished only to you for your use solely in connection with the Actions and may not be relied upon by anyone else or for any other purpose without our prior written consent. No opinions other than those expressly stated herein are implied or shall be inferred as a result of anything contained in or omitted from this letter. The opinions expressed in this letter are stated only as of the time of its delivery, and we disclaim any obligation to revise or supplement this letter thereafter. The scope of our engagement has not extended beyond the examinations and rendering of the opinions expressed herein. Our engagement as bond counsel in connection with the Actions is concluded upon delivery of this letter.

Respectfully submitted,

TAFT STETTINIUS & HOLLISTER LLP

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DUKE ENERGY KENTUCKY
CASE NO. 2022-00372
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(k)

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807 KAR 5:001, SECTION 16(7)(k)

Description of Filing Requirement:

The most recent FERC Financial Report FERC Form No.1, FERC Financial Report FERC Form No. 2, or Public Service Commission Form T (telephone).

Response:

See attached.

Witness Responsible:

Danielle L. Weatherston

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

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
Duke Energy Kentucky, Inc.	End of: 2021/ Q4

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

GENERAL INFORMATION

Purpose

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

Who Must Submit

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

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

one million megawatt hours of total annual sales,

100 megawatt hours of annual sales for resale,

500 megawatt hours of annual power exchanges delivered, or

500 megawatt hours of annual wheeling for others (deliveries plus losses).

What and Where to Submit

Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

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

Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

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

The CPA Certification Statement should:

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

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

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

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

year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/general-information-0/electric-industry-forms.

When to Submit

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

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

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

Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

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

Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the

the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

“In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

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

'Person' means an individual or a corporation;

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

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

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

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

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

"Sec. 304.

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

"Sec. 309.

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

GENERAL PENALTIES

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

FERC FORM NO. 1
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Duke Energy Kentucky, Inc.		02 Year/ Period of Report End of: 2021/ 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) 1262 Cox Road, Erlanger, KY 41018		
05 Name of Contact Person Kalejah Pierce		06 Title of Contact Person Accounting Analyst
07 Address of Contact Person (Street, City, State, Zip Code) 526 S. Church Street, Charlotte, NC 28202		
08 Telephone of Contact Person, Including Area Code 704-731-4024	09 This Report is An Original / A Resubmission (1) ☐ An Original (2) ☑ A Resubmission	10 Date of Report (Mo, Da, Yr) 04/18/2022

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 Cynthia S. Lee	03 Signature Cynthia S. Lee	04 Date Signed (Mo, Da, Yr) 04/18/2022
02 Title VP, CAO, and Controller		

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: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ 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".

22	Materials and Supplies	227	
23	Allowances	228	
24	Extraordinary Property Losses	230a	N/A
25	Unrecovered Plant and Regulatory Study Costs	230b	N/A
26	Transmission Service and Generation Interconnection Study Costs	231	N/A
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254b	N/A
33	Long-Term Debt	256	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262	
36	Accumulated Deferred Investment Tax Credits	266	
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	N/A
39	Accumulated Deferred Income Taxes-Other Property	274	
40	Accumulated Deferred Income Taxes-Other	276	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300	
43	Regional Transmission Service Revenues (Account 457.1)	302	
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310	
46	Electric Operation and Maintenance Expenses	320	
47	Purchased Power	326	
48	Transmission of Electricity for Others	328	
49	Transmission of Electricity by ISO/RTOs	331	N/A
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	

52	**Depreciation and Amortization of Electric Plant (Account 403, 404, 405)**	336	
53	**Regulatory Commission Expenses**	350	
54	**Research, Development and Demonstration Activities**	352	
55	**Distribution of Salaries and Wages**	354	
56	**Common Utility Plant and Expenses**	356	
57	**Amounts included in ISO/RTO Settlement Statements**	397	
58	**Purchase and Sale of Ancillary Services**	398	
59	**Monthly Transmission System Peak Load**	400	N/A
60	**Monthly ISO/RTO Transmission System Peak Load**	400a	N/A
61	**Electric Energy Account**	401a	
62	**Monthly Peaks and Output**	401b	
63	**Steam Electric Generating Plant Statistics**	402	
64	**Hydroelectric Generating Plant Statistics**	406	N/A
65	**Pumped Storage Generating Plant Statistics**	408	N/A
66	**Generating Plant Statistics Pages**	410	N/A
0	**Energy Storage Operations (Large Plants)**	414	N/A
67	**Transmission Line Statistics Pages**	422	
68	**Transmission Lines Added During Year**	424	
69	**Substations**	426	
70	**Transactions with Associated (Affiliated) Companies**	429	
71	**Footnote Data**	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☐ Two copies will be submitted ☐ No annual report to stockholders is prepared		

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ 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.

Cynthia S. Lee

Vice President, Chief Accounting Officer and Controller

526 S. Church Street, Charlotte, NC 28202

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.

State of Incorporation: KY

Date of Incorporation: 1901-03-20

Incorporated Under Special Law:

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.

(a) Name of Receiver or Trustee Holding Property of the Respondent: N/A

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created: N/A

(d) Date when possession by receiver or trustee ceased:

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

Kentucky - Gas and Electric

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

(1) ☐ Yes

(2) ☑ No

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

CONTROL OVER RESPONDENT

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

Duke Energy Kentucky, Inc is a wholly owned subsidiary of Duke Energy Ohio, Inc. Duke Energy Ohio, Inc. is a wholly owned subsidiary of Cinergy Corp. , which is a wholly owned subsidiary of Duke Energy Corporation.

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

Definitions

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	N/A			

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1	Executive Vice President, Energy Solutions and President, Midwest/Florida Regions and Natural Gas Business	Douglas F. Esamann		2021-01-01	2021-04-30
2	Vice President and Chief Ethics and Compliance Officer	Melissa M. Feldmeier			
3	Executive Vice President, Chief Legal Officer and Corporate Secretary	Kodwo Ghartey-Tagoe			
4	Chief Executive Officer	Lynn J. Good			
5	Senior Vice President, Chief Accounting Officer, Tax and Controller	Dwight L. Jacobs		2021-01-01	2021-05-15
6	Executive Vice President & Chief Operating Officer	Dhiaa M. Jamil			
7	Executive Vice President	Julie S. Janson			
8	Vice President, Chief Accounting Officer and Controller	Cynthia S. Lee		2021-05-16	
9	Senior Vice President, Corporate Development and Treasurer	Karl W. Newlin			
10	Senior Vice President and Chief Human Resources Officer	Ronald R. Reising			
11	Executive Vice President, Chief Strategy and Commercial Officer	Brian D. Savoy			
12	Executive Vice President, Customer Experience, Solutions, and Services	Harry K. Sideris			
13	President	Amy B. Spiller			
14	Senior Vice President, Natural Gas Business	Alexander J. Weintraub			
15	Executive Vice President & Chief Financial Officer	Steven K. Young			

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ 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), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	R. Alexander Glenn, Senior Vice President	526 S Church St, Charlotte NC 28202	true	
2	Lynn J. Good, Chief Executive Officer	526 S Church St, Charlotte NC 28202		true
3	Dhiaa M. Jamil, Executive Vice President and Chief Operating Officer	526 S Church St, Charlotte NC 28202	true	

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	☐ Yes ☑ No

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

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
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Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

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

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

☑ Yes

☐ No

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

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20120515-5244	05/15/2012	ER12-91-000	Formula Rate Annual Update	PJM OATT, Attachment H-22A
2	20130129-5070	01/29/2013	ER12-91-000	Formula Rate Annual Update Corrected	PJM OATT, Attachment H-22A
3	20130515-5122	05/15/2013	ER12-91-000	Formula Rate Annual Update	PJM OATT, Attachment H-22A
4	20140515-5149	05/15/2014	ER12-91-000	Formula Rate Annual Update	PJM OATT, Attachment H-22A
5	20150515-5244	05/15/2015	ER12-91-000	Formula Rate Annual Update	PJM OATT, Attachment H-22A
6	20160513-5092	05/13/2016	ER12-91-000	Formula Rate Annual Update	PJM OATT, Attachment H-22A
7	20161130-5416	11/30/2016	ER12-91-000	Formula Rate Annual Update Corrected	PJM OATT, Attachment H-22A
8	20170509-5150	05/09/2017	ER12-91-000	Formula Rate Annual Update	PJM OATT, Attachment H-22A
9	20180129-5213	01/29/2018	ER12-91-000	Formula Rate Annual Update Corrected	PJM OATT, Attachment H-22A
10	20180515-5331	05/15/2018	ER12-91-000	Formula Rate Annual Update	PJM OATT, Attachment H-22A
11	20180402-5140	04/02/2018	ER18-1274-000	Section 205	PJM OATT, Attachment H-22A & H-22B
12	20181214-5040	12/14/2018	ER19-555-000	Section 205	PJM OATT, Attachment H-22A
13	20190329-5217	03/29/2019	ER19-1483-000	Section 205	PJM OATT, Attachment H-22A
14	20190515-5112	05/15/2019	ER12-91-000	Formula Rate Annual Update	PJM OATT, Attachment H-22A
15	20200207-5054	02/07/2020	ER12-91-000	Formula Rate Annual Update Corrected	PJM OATT, Attachment H-22A
16	20200515-5294	05/15/2020	ER12-91-000	Formula Rate Annual Update	PJM OATT, Attachment H-22A
17	20210517-5120	05/17/2021	ER12-91-000	Formula Rate Annual Update	PJM OATT, Attachment H-22A
18	20210115-5207	01/15/2021	ER20-1832-000	Order No. 864 Compliance Filing	PJM OATT, Attachment H-22A
19	20210316-5124	03/16/2021	ER21-1450-000	Update to Formula Rate Annual Update (2020-Materials and Supplies)	PJM OATT, Attachment H-22A

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

INFORMATION ON FORMULA RATES - Formula Rate Variances

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

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
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Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Pages 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.

None

See Notes to Financial Statements, Note 1, "Summary of Significant Accounting Policies"

See Notes to Financial Statements, Note 2, "Regulatory Matters"

None

There are no changes to report during the fourth quarter 2021. There are no changes to report during the third quarter 2021.
During the second quarter 2021, Project DKY212502.Grant Metering was completed, in-service date of April 8, 2021; and Project DKY213203.Longbranch EKPC CIR 6785 TL was completed, in-service date of May 6, 2021, installed on 2 steel structures.
There are no changes to report during the first quarter 2021.

See Notes to Financial Statements, Note 5, "Debt and Credit Facilities"

None

During the fourth quarter 2021, there were no large scale wage changes for Duke Energy Kentucky payroll company. During the third quarter 2021, there were no large scale wage changes for Duke Energy Kentucky payroll company. During the second quarter 2021, there were no large scale wage changes for Duke Energy Kentucky payroll company. During the first quarter 2021, exempt and non-exempt employees in Duke Energy Kentucky payroll companies received merit increases of $3,327.
See Notes to Financial Statements, Note 2, "Regulatory Matters" and Note 3,"Commitments and Contingencies"
None
None

There are no changes to major security holders and voting powers of Duke Energy Kentucky, Inc. that occurred during the fourth quarter 2021.

The changes in officers and directors for Duke Energy Kentucky, Inc. that occurred during the fourth quarter 2021 are as follows:

Appointments effective 11/01/21	
Cameron D. McDonald	Vice President, Chief Diversity and Inclusion Officer, Talent Agility and Acquisition
Resignations effective 11/01/21	
Cameron D. McDonald	Vice President, Human Resources, Transformation & Employee Development
There are no changes in major security holders and voting powers of Duke Energy Kentucky, Inc that occurred during the third quarter of 2021.	
The changes in officers and directors for Duke Energy Kentucky, Inc. that occurred during the third quarter of 2021 are as follows:	
Appointments effective 07/01/21	
Ariane S. Johnson	Assistant Corporate Secretary
Resignations effective 08/01/21	
Douglas F. Esamann	Advisor to the Chair, President and Chief Executive Officer
Resignations effective 07/01/21	
John B. Scheidler	Assistant Corporate Secretary
There are no changes in major security holders and voting powers of Duke Energy Kentucky, Inc that occurred during the second quarter of 2021.	
The changes in officers and directors for Duke Energy Kentucky, Inc. that occurred during the second quarter of 2021 are as follows:	
Appointments effective 05/16/21	
Dwight L. Jacobs	Senior Vice President, Supply Chain and Chief Procurement Officer
Cynthia S. Lee	Vice President, Chief Accounting Officer and Controller
Appointments effective 05/01/21	
Jessica L. Bednarcik	Senior Vice President, Environmental, Health and Safety and Coal Combustion Products
Melody Birmingham	Senior Vice President and Chief Administrative Officer
Swati V. Daji	Senior Vice President, Enterprise Strategy and Planning
Diane V. Denton	Vice President, Integrated Planning, Florida and Midwest
Paul Draovitch	Senior Vice President, Chief Regulated and Renewable Energy Officer
Douglas F. Esamann	Advisor to the Chair, President and Chief Executive Officer
Christopher M. Fallon	Senior Vice President and President, Duke Energy Sustainable Solutions
Nicholas J. Giaimo	Vice President, Financial Planning and Analysis
R. Alexander Glenn	Director
R. Alexander Glenn	Senior Vice President
Julia S. Janson	Executive Vice President
Michael Luhrs	Vice President, Integrated Grid Strategy
Louis E. Renjel	Senior Vice President, External Affairs and Communications
Regis T. Repko	Senior Vice President, Generation and Transmission Strategy
Brian D. Savoy	Executive Vice President, Chief Strategy and Commercial Officer
Harry K. Sideris	Executive Vice President, Customer Experience, Solutions, and Services
Resignations effective 05/16/21	
Dwight L. Jacobs	Senior Vice President, Chief Accounting Officer, Tax and Controller
Resignations effective 05/01/21	
Melody Birmingham	Senior Vice President, Supply Chain and Chief Procurement Officer
Cari P. Boyce	Senior Vice President, Enterprise Strategy and Planning
William E. Currens Jr.	Senior Vice President, Financial Planning and Analysis
Swati V. Daji	Senior Vice President, Customer Solutions and Strategies
Paul Draovitch	Senior Vice President, Environmental, Health and Safety and Project Management and Controls
Douglas F. Esamann	Director
Douglas F. Esamann	Executive Vice President, Energy Solutions and President, Midwest/Florida Regions and Natural Gas Business
Christopher M. Fallon	President, Duke Energy Renewables and Senior Vice President, Delivery & Operations
Julia S. Janson	Executive Vice President, External Affairs and President, Carolinas Region
Louis E. Renjel	Senior Vice President, Federal Government and Corporate Affairs
Regis T. Repko	Senior Vice President, Chief Regulated & Renewable Energy Officer
Brian D. Savoy	Senior Vice President, Chief Transformation and Administrative Officer
Harry K. Sideris	Senior Vice President, Customer Experience and Services
There are no changes in major security holders and voting powers of Duke Energy Kentucky, Inc that occurred during the first quarter of 2021.	
The changes in officers and directors for Duke Energy Kentucky, Inc. that occurred during the first quarter of 2021 are as follows:	
Appointments effective 02/01/21	
Christopher Bauer	Assistant Treasurer
Kenna Jordan	Assistant Corporate Secretary
Regis T. Repko	Senior Vice President, Chief Regulated & Renewable Energy Officer
Resignations effective 02/1/21	
Regis T. Repko	Senior Vice President and Chief Fossil/Hydro Officer
John L. Sullivan, III	Assistant Treasurer

N/A

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ 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	2,996,350,732	2,881,491,826
3	Construction Work in Progress (107)	200	96,259,188	70,446,121
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		3,092,609,920	2,951,937,947
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	1,073,764,061	1,044,742,638
6	Net Utility Plant (Enter Total of line 4 less 5)		2,018,845,859	1,907,195,309
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202		
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)			
10	Spent Nuclear Fuel (120.4)			
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202		
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)			
14	Net Utility Plant (Enter Total of lines 6 and 13)		2,018,845,859	1,907,195,309
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		1,247,563	1,220,439
19	(Less) Accum. Prov. for Depr. and Amort. (122)			
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		1,500	1,500
25	Sinking Funds (125)			
26	Depreciation Fund (126)			

27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		16,381,482	12,851,866
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)		111,502	317,782
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		17,742,047	14,391,587
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		5,482,547	4,296,974
36	Special Deposits (132-134)			
37	Working Fund (135)			
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		20,694,605	6,233,908
41	Other Accounts Receivable (143)		2,142,390	1,981,275
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		314,921	324,092
43	Notes Receivable from Associated Companies (145)		22,396,503	21,030,759
44	Accounts Receivable from Assoc. Companies (146)		9,106,248	2,001,212
45	Fuel Stock (151)	227	32,848,807	30,021,194
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	16,707,317	17,576,107
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	19,189	19,921
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227	(22,522)	84,712
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			

57	Prepayments (165)		1,293,933	428,870
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)		4,020	21,480
61	Accrued Utility Revenues (173)			
62	Miscellaneous Current and Accrued Assets (174)		10,884,227	7,863,991
63	Derivative Instrument Assets (175)		1,635,966	1,379,378
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		111,502	317,782
65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		122,766,807	92,297,907
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		2,718,168	3,114,783
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	140,633,411	136,150,402
73	Prelim. Survey and Investigation Charges (Electric) (183)		389,939	447,199
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)		5	4
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	2,215,689	2,156,140
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		394,481	517,204
82	Accumulated Deferred Income Taxes (190)	234	70,722,124	73,220,723
83	Unrecovered Purchased Gas Costs (191)		1,128,482	(3,514,021)
84	Total Deferred Debits (lines 69 through 83)		218,202,299	212,092,434
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		2,377,557,012	2,225,977,237

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ 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	8,779,995	8,779,995
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)		18,838,946	18,838,946
7	Other Paid-In Capital (208-211)	253	273,655,189	223,655,189
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b		
11	Retained Earnings (215, 215.1, 216)	118	520,368,338	466,962,758
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118		
13	(Less) Reaquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)		
16	Total Proprietary Capital (lines 2 through 15)		821,642,468	718,236,888
17	**LONG-TERM DEBT**			
18	Bonds (221)	256		
19	(Less) Reaquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256	25,000,000	25,000,000
21	Other Long-Term Debt (224)	256	706,720,000	706,720,000
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		174,038	186,301
24	Total Long-Term Debt (lines 18 through 23)		731,545,962	731,533,699
25	**OTHER NONCURRENT LIABILITIES**			

26	Obligations Under Capital Leases - Noncurrent (227)		8,378,503	8,696,322
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		(79,788)	(83,933)
29	Accumulated Provision for Pensions and Benefits (228.3)		30,843,612	31,431,080
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)			
32	Long-Term Portion of Derivative Instrument Liabilities		3,693,879	5,290,232
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		93,282,532	76,111,813
35	Total Other Noncurrent Liabilities (lines 26 through 34)		136,118,738	121,445,514
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)			
38	Accounts Payable (232)		45,980,386	41,066,542
39	Notes Payable to Associated Companies (233)		102,596,001	75,472,000
40	Accounts Payable to Associated Companies (234)		14,614,111	16,595,167
41	Customer Deposits (235)		9,122,676	9,136,959
42	Taxes Accrued (236)	262	9,222,510	18,784,698
43	Interest Accrued (237)		7,529,336	7,611,627
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		2,940,535	2,099,990
48	Miscellaneous Current and Accrued Liabilities (242)		5,943,819	8,260,083
49	Obligations Under Capital Leases-Current (243)		317,820	292,937
50	Derivative Instrument Liabilities (244)		4,644,858	6,298,964
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		3,693,879	5,290,232
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		199,218,173	180,328,735
55	**DEFERRED CREDITS**			

56	Customer Advances for Construction (252)		1,645,440	1,595,027
57	Accumulated Deferred Investment Tax Credits (255)	266	3,559,977	3,618,035
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	14,246,484	14,622,647
60	Other Regulatory Liabilities (254)	278	130,898,991	138,994,834
61	Unamortized Gain on Reaquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)		301,962,482	285,156,597
64	Accum. Deferred Income Taxes-Other (283)		36,718,297	30,445,261
65	Total Deferred Credits (lines 56 through 64)		489,031,671	474,432,401
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		2,377,557,012	2,225,977,237

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

STATEMENT OF INCOME

Quarterly

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

Annual or Quarterly if applicable

Do not report fourth quarter data in columns (e) and (f)
Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
Use page 122 for important notes regarding the statement of income for any account thereof.
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.
Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
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.
Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

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)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	514,640,093	445,665,255			399,019,808	346,892,088	115,620,285	98,773,167		
3	Operating Expenses											
4	Operation Expenses (401)	320	286,402,185	235,673,671			225,147,072	188,781,980	61,255,113	46,891,691		
5	Maintenance Expenses (402)	320	38,272,692	35,779,342			36,185,319	33,864,124	2,087,373	1,915,218		
6	Depreciation Expense (403)	336	64,618,518	61,396,656			48,640,753	46,871,823	15,977,765	14,524,833		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336										
8	Amort. & Depl. of Utility Plant (404-405)	336	7,862,366	7,471,556			3,543,320	3,600,538	4,319,046	3,871,018		
9	Amort. of Utility Plant Acq. Adj. (406)	336										
10												

	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)											
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)		12,706,512	10,835,750			10,201,756	9,993,465	2,504,756	842,285		
13	(Less) Regulatory Credits (407.4)		7,000,556	6,557,984			6,897,985	6,444,590	102,571	113,394		
14	Taxes Other Than Income Taxes (408.1)	262	20,498,702	16,918,072			15,842,108	13,169,657	4,656,594	3,748,415		
15	Income Taxes - Federal (409.1)	262	(8,052,386)	2,044,705			(8,317,550)	(498,211)	265,164	2,542,916		
16	Income Taxes - Other (409.1)	262	(2,502,787)	271,995			(2,533,237)	329,389	30,450	(57,394)		
17	Provision for Deferred Income Taxes (410.1)	234, 272	59,111,911	41,108,598			47,582,356	32,009,110	11,529,555	9,099,488		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	38,405,762	34,315,896			30,003,029	26,622,848	8,402,733	7,693,048		
19	Investment Tax Credit Adj. - Net (411.4)	266	(58,058)	(61,175)			(428)	(428)	(57,630)	(60,747)		
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)		183,883	59,444			183,883	59,444				
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)		433,269,454	370,505,846			339,206,572	294,994,565	94,062,882	75,511,281		
27	Net Util Oper Inc (Enter Tot line 2 less 25)		81,370,639	75,159,409			59,813,236	51,897,523	21,557,403	23,261,886		
28	Other Income and Deductions											
29	Other Income											
30	Nonutilty Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,418,388	1,300,789								
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		132,598	79,842								
33	Revenues From Nonutility Operations (417)		(5)	(50)								
34	(Less) Expenses of Nonutility Operations (417.1)		65,209	56,068								
35	Nonoperating Rental Income (418)											
36	Equity in Earnings of Subsidiary Companies (418.1)	119										

37	Interest and Dividend Income (419)		981,836	965,254								
38	Allowance for Other Funds Used During Construction (419.1)		1,259,856	(124,641)								
39	Miscellaneous Nonoperating Income (421)		977,722	1,059,499								
40	Gain on Disposition of Property (421.1)											
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		4,439,990	3,064,941								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)											
44	Miscellaneous Amortization (425)											
45	Donations (426.1)		413,987	255,853								
46	Life Insurance (426.2)		(9,857)	(2,326)								
47	Penalties (426.3)		166,667	2,500								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		454,776	495,762								
49	Other Deductions (426.5)		3,817,077	1,218,343								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		4,842,650	1,970,132								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	(1,176)	104,393								
53	Income Taxes-Federal (409.2)	262	1,098,161	2,180,902								
54	Income Taxes-Other (409.2)	262	273,404	544,528								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	514,292	122,704								
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	1,918,797	2,188,314								
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)		(34,116)	764,213								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		(368,544)	330,596								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		25,860,084	24,665,700								

63	Amort. of Debt Disc. and Expense (428)		555,657	392,830								
64	Amortization of Loss on Reaquired Debt (428.1)		122,723	171,778								
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)		141,453	755,884								
68	Other Interest Expense (431)		1,366,279	1,360,229								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		449,681	(288)								
70	Net Interest Charges (Total of lines 62 thru 69)		27,596,515	27,346,709								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		53,405,580	48,143,296								
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										
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		53,405,580	48,143,296								

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		466,962,758	418,819,462
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1	Current Expected Credit Losses (CECL) adjustments	283		
4.2	Current Expected Credit Losses (CECL) adjustments	190		
4.3				
4.4				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
10.1				
10.2				
10.3	Current Expected Credit Losses (CECL) adjustments	186		
10.4	Current Expected Credit Losses (CECL) adjustments	144		
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		53,405,580	48,143,296
17	Appropriations of Retained Earnings (Acct. 436)			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			

23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	Cash Dividend to Parent			
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		520,368,338	466,962,758
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		520,368,338	466,962,758
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
52.1	Transfers from Unappropriated Retained Earnings (Account 216)			
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ 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 Instructions 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)	53,405,580	48,143,296
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	64,618,518	61,396,656
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Primary Nuclear Fuel		
5.2	Plant Items	10,133,866	7,471,556
5.3	Debt Discount, Premium, Expense, and Loss on Reacquired Debt	678,380	564,608
8	Deferred Income Taxes (Net)	19,301,644	4,727,092
9	Investment Tax Credit Adjustment (Net)	(58,058)	(61,175)
10	Net (Increase) Decrease in Receivables	(21,718,559)	7,295,872
11	Net (Increase) Decrease in Inventory	(1,851,589)	781,424
12	Net (Increase) Decrease in Allowances Inventory	732	933
13	Net Increase (Decrease) in Payables and Accrued Expenses	(18,305,865)	13,717,391
14	Net (Increase) Decrease in Other Regulatory Assets	(7,585,119)	(2,311,411)
15	Net Increase (Decrease) in Other Regulatory Liabilities	(2,479,911)	(1,214,007)
16	(Less) Allowance for Other Funds Used During Construction	1,259,856	(124,641)
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	Other (provide details in footnote):		
18.2	Special funds	(2,197,548)	(910,762)

18.3	Prepayments	5,479,620	1,008,692
18.4	Miscellaneous Current and Accrued Assets	(445,803)	210,540
18.5	Preliminary Survey and Investigation Charges	57,260	(91,894)
18.6	Clearing Accounts		4,584
18.7	Temporary Facilities		
18.8	Miscellaneous Deferred Debits	(59,549)	379,620
18.9	Unrecovered Purchased Gas Costs	(4,642,503)	(784,818)
18.10	Accumulated Other Comprehensive Income		
18.11	Obligations Under Capital Leases - Noncurrent	(317,819)	(292,937)
18.12	Accumulated Provisions	369,326	(62,781)
18.13	Accumulated Provision for Rate Refund		
18.14	Contribution to Pension Plan		
18.15	Customer Advances for Construction	50,413	(10,172)
18.16	Other Deferred Credits	(376,163)	285,734
18.17	Derivative Instruments	148,527	1,006,439
18.18	Net Utility Plant and Nonutility Property	12,616,650	7,138,729
18.19	Debt Expenses	(23,500)	(314,125)
18.20	Deferred Income Taxes	391,237	219,894
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	105,929,911	148,423,619
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(181,350,003)	(232,636,624)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant	(289,169)	(1,376,428)
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	(1,259,856)	124,641
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(180,379,316)	(234,137,693)
36			

	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
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	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables	(1,365,744)	(5,002,000)
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):		
53.1	Cost of Removal net of salvage		
53.2	Other (provide details in footnote):		
53.3	Other investments		
53.4	Withdrawals, issuances, and redemptions of restricted funds held in trust		
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(181,745,060)	(239,139,693)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	50,000,000	70,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Other (provide details in footnote):		
64.2	Notes Payable to Associated Companies		
64.3	Other Financing Activities (provide details in footnote):		
66	Net Increase in Short-Term Debt (c)		

67	Other (provide details in footnote):		
67.1	Other (provide details in footnote):		
67.2	Contribution from Parent	50,000,000	25,000,000
70	Cash Provided by Outside Sources (Total 61 thru 69)	100,000,000	95,000,000
72	Payments for Retirement of:		
73	Long-term Debt (b)	(50,014,560)	
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):		
76.2	Intercompany Notes Payable MoneyPool	27,124,001	(7,037,000)
76.3	Premium payments and fees on deferred debt	(108,719)	(95,616)
76.4	Fair market value adjustment		
76.5	Bond Issuance Costs		
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock		
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	77,000,722	87,867,384
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	1,185,573	(2,848,690)
88	Cash and Cash Equivalents at Beginning of Period	4,296,974	7,145,664
90	Cash and Cash Equivalents at End of Period	[a]5,482,547	4,296,974

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: CashAndCashEquivalents

	YTD December 2021	YTD December 2020
Supplemental Disclosures (in thousands)		
Cash paid for interest, net of amount Capital	$ 25,688	$ 24,857
Cash paid / (refunded) for income taxes	$ 2,019	$ 1,822
Significant non-cash transactions (in thousands)		
AFUDC - equity component	$ 1,260	$ (125)
Accrued capital expenditures	$ 28,490	$ 24,529
Cash and Cash Equivalents at End of period:		
Cash (131)	$ 5,482,547	$ 4,296,974
Working Funds (135)	$ 0	$ 0
Temporary Cash Investments (136)	$ 0	$ 0
	$ 5,482,547	$ 4,296,974

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

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.

This Federal Energy Regulatory Commission (FERC) Form 1 has been prepared in conformity with the requirements of the FERC 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 in the United States of America (GAAP). The following areas represent the significant differences between the Uniform System of Accounts and GAAP

- GAAP requires that public business enterprises report certain information about operating segments in complete sets of financial statements of the enterprise and certain information about their products and services, which are not required for FERC reporting purposes.
- GAAP requires that majority-owned subsidiaries be consolidated for financial reporting purposes. FERC requires that majority-owned subsidiaries be separately reported as Investment in Subsidiary Companies, unless an appropriate waiver has been granted by the FERC.
- FERC requires that income or losses of an unusual nature and infrequent occurrence, which would significantly distort the current year's income, be recorded as extraordinary income or deductions, respectively.
- GAAP requires that removal and nuclear decommissioning costs for property that does not have an associated legal retirement obligation be presented as a regulatory liability on the Balance Sheet. These costs are presented as accumulated depreciation on the Balance Sheet for FERC reporting purposes.
- GAAP requires the regulatory assets and liabilities resulting from the implementation of ASC 740-10 (formerly SFAS No. 109) be presented as a net amount on the balance sheet. For FERC reporting purposes, these assets and liabilities are presented separately and are included in the Other Regulatory Asset and Other Regulatory Liability line items.
- GAAP requires that the current portion of regulatory assets and regulatory liabilities be reported as current assets and current liabilities, respectively, on the Balance Sheet. FERC requires that the current portion of regulatory assets and liabilities be reported as Regulatory Assets within Deferred Debits and Regulatory Liabilities within Deferred Credits, respectively.
- GAAP requires that the current portion of long-term debt and preferred stock be reported as a current liability on the Balance Sheet. FERC requires that the current portion of long-term debt and preferred stock be reported as Long-term Debt and Proprietary Capital.
- GAAP requires that any deferred costs associated with a specific debt issuance be presented as a reduction to debt on the Balance Sheet. FERC requires any Unamortized Debt Expense to be separately stated as a Deferred Debit on the Balance Sheet.
- GAAP requires that certain account balances within financial statement line items which are not in the natural position for that line item (e.g. an account within Accounts Receivable with a credit balance) be reclassed to the appropriate side of the Balance Sheet. FERC does not require certain accounts which are not in a natural position for their respective line item to be reclassed, as long as the line item in total is in its natural position.
- GAAP requires that regulated assets that are abandoned or retired early, including the cost of the asset and its associated accumulated depreciation, be reclassified to a separate regulatory asset on the Balance Sheet. For FERC reporting purposes, those assets which have been abandoned but are still operating are maintained in their original balance sheet accounts.
- GAAP requires that the current portion of Asset Retirement Obligations be reported as current liabilities on the Balance Sheet. For FERC reporting purposes, these liabilities are not reported separately and are reflected as Asset Retirement Obligations within the Other Noncurrent Liabilities section of the Balance Sheet.
- GAAP requires service cost related to pensions and Post-Retirement Benefits Other Than Pensions (PBOP) to be reported with other compensation costs arising from services rendered by employees during the period and included in a subtotal of income from operations on the income statement. Non-service cost components are presented separately outside the subtotal of income from operations on the income statement. For FERC reporting purposes, costs related to pensions and PBOP is included in the Net Utility Operating Income of the income statement.

Duke Energy Kentucky's notes to the financial statements have been prepared in conformity with GAAP. Accordingly, certain footnotes are not reflective of Duke Energy Kentucky's financial statements contained herein. Management has evaluated the impact of events occurring after December 31, 2021 up to March 11, 2022, the date that Duke Energy Kentucky's U.S. GAAP financial statements were issued

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

NATURE OF OPERATIONS AND BASIS OF PRESENTATION

Duke Energy Kentucky is a combination electric and natural gas regulated public utility company that provides service in northern Kentucky. Duke Energy Kentucky's principal lines of business include generation, transmission, distribution and sale of electricity, as well as the transportation and sale of natural gas. Duke Energy Kentucky is subject to the regulatory provisions of the KPSC and the FERC. Duke Energy Kentucky's common stock is wholly owned by Duke Energy Ohio, Inc., an indirect wholly owned subsidiary of Duke Energy.

Certain prior year amounts have been reclassified to conform to the current year presentation.

Other Current Assets and Liabilities

The following table provides a description of amounts included in Other within Current Assets or Current Liabilities that exceed 5% of total Current Assets or Current Liabilities on the Duke Energy Kentucky Balance Sheets at either December 31, 2021, or 2020.

(in thousands)	Location	December 31, 2021		December 31, 2020
Income Taxes Receivable	Current Assets $	8,717	$	140

SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

In preparing financial statements that conform to GAAP, Duke Energy Kentucky must make estimates and assumptions that affect the reported amounts of assets and liabilities, the reported amounts of revenues and expenses and the disclosure of contingent assets and liabilities at the date of the financial statements. Actual results could differ from those estimates.

Regulatory Accounting

The majority of Duke Energy Kentucky's operations are subject to price regulation for the sale of electricity and natural gas by the KPSC or FERC. When prices are set on the basis of specific costs of the regulated operations and an effective franchise is in place such that sufficient natural gas or electric services can be sold to recover those costs, Duke Energy Kentucky applies regulatory accounting. Regulatory accounting changes the timing of the recognition of costs or revenues relative to a company that does not apply regulatory accounting. As a result, regulatory assets and regulatory liabilities are recognized on the Balance Sheets and are amortized consistent with the treatment of the related cost in the ratemaking process. Regulatory assets are reviewed for recoverability each reporting period. If a regulatory asset is no longer deemed probable of recovery, the deferred cost is charged to earnings. See Note 2 for further information.

Duke Energy Kentucky utilizes cost-tracking mechanisms, commonly referred to as fuel adjustment clauses or purchased gas adjustment clauses. These clauses allow for the recovery of fuel and fuel-related costs, portions of purchased power, natural gas costs and hedging costs through surcharges on customer rates. The difference between the costs incurred and the surcharge revenues is recorded either as an adjustment to Operating Revenues, Operating Expenses - Fuel used in electric generation and purchased power or Operating Expenses - Cost of natural gas on the Statements of Operations with an off-setting impact on regulatory assets or regulatory liabilities.

Cash and Cash Equivalents

All highly liquid investments with maturities of three months or less at the date of acquisition are considered cash equivalents.

Inventory

Inventory related to regulated operations is valued at historical cost. Inventory is charged to expense or capitalized to property, plant and equipment when issued, primarily using the average cost method. Excess or obsolete inventory is written-down to the lower of cost or net realizable value. Once inventory has been written-down, it creates a new cost basis for the inventory that is not subsequently written-up. Provisions for inventory write-offs were not material at December 31, 2021, and 2020. The components of inventory are presented in the table below.

(in thousands)		December 31, 2021		December 31, 2020
Materials and supplies	$	16,685	$	17,661
Coal		18,978		16,052
Natural gas, oil and other		13,871		13,969
Total inventory	$	49,534	$	47,682

Long-Lived Asset Impairments

Duke Energy Kentucky evaluates long-lived assets for impairment when circumstances indicate the carrying value of those assets may not be recoverable. An impairment exists when a long-lived asset's carrying value exceeds the estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. The estimated cash flows may be based on alternative expected outcomes that are probability weighted. If the carrying value of the long-lived asset is not recoverable based on these estimated future undiscounted cash flows, the carrying value of the asset is written-down to its then-current estimated fair value and an impairment charge is recognized.

Duke Energy Kentucky assesses the fair value of long-lived assets using various methods, including recent comparable third-party sales, internally developed discounted cash flow analysis and analysis from outside advisors. Triggering events to reassess cash flows may include, but are not limited to, significant changes in commodity prices, the condition of an asset or management's interest in selling the asset.

Property, Plant and Equipment

Property, plant and equipment are stated at the lower of depreciated historical cost net of any disallowances or fair value, if impaired. Duke Energy Kentucky capitalizes all construction-related direct labor and material costs, as well as indirect construction costs such as general engineering, taxes and financing costs. See "Allowance for Funds Used During Construction and Interest Capitalized" below for information on capitalized financing costs. Costs of renewals and betterments that extend the useful life of property, plant and equipment are also capitalized. The cost of repairs, replacements and major maintenance projects, which do not extend the useful life or increase the expected output of the asset, are expensed as incurred. Depreciation is generally computed over the estimated useful life of the asset using the composite straight-line method. Depreciation studies are conducted periodically to update composite rates and are approved by the KPSC and/or the FERC when required. The composite weighted average depreciation rate was 2.4% for the years ended December 31, 2021, and 2020.

In general, when Duke Energy Kentucky retires its regulated property, plant and equipment, the original cost plus the cost of retirement, less salvage value and any depreciation already recognized, is charged to accumulated depreciation. However, when it becomes probable a regulated asset will be retired substantially in advance of its original expected useful life or will be abandoned, the cost of the asset and the corresponding accumulated depreciation is recognized as a separate asset. If the asset is still in operation, the net amount is classified as Generation facilities to be retired, net on the Balance Sheets. If the asset is no longer operating, the net amount is classified in Regulatory assets on the Balance Sheets if deemed recoverable (see discussion of long-lived asset impairments above). The carrying value of the asset is based on historical cost if Duke Energy Kentucky is allowed to recover the remaining net book value and a return equal to at least the incremental borrowing rate. If not, an impairment is recognized to the extent the net book value of the asset exceeds the present value of future revenues discounted at the incremental borrowing rate.

When Duke Energy Kentucky sells entire regulated operating units, the original cost and accumulated depreciation and amortization balances are removed from Property, Plant and Equipment on the Balance Sheets. Any gain or loss is recorded in earnings, unless otherwise required by the KPSC and/or the FERC. See Note 7 for further information.

Leases

Duke Energy Kentucky determines if an arrangement is a lease at contract inception based on whether the arrangement involves the use of a physically distinct identified asset and whether Duke Energy Kentucky has the right to obtain substantially all of the economic benefits from the use of the asset throughout the period as well as the right to direct use of the asset. As a policy election, Duke Energy Kentucky does not evaluate arrangements with initial contract terms of less than one year as leases.

Operating leases are included in Operating lease ROU assets, net, Other current liabilities and Operating lease liabilities on the Balance Sheets.

For lessee and lessor arrangements, Duke Energy Kentucky has elected a policy to not separate lease and non-lease components for all asset classes. For lessor arrangements, lease and non-lease components are only combined under one arrangement and accounted for under the lease accounting framework if the non-lease components are not the predominant component of the arrangement and the lease component would be classified as an operating lease.

Allowance for Funds Used During Construction and Interest Capitalized

For regulated operations, the debt and equity costs of financing the construction of property, plant and equipment are reflected as AFUDC and capitalized as a component of the cost of property, plant and equipment. AFUDC equity is reported on the Statements of Operations as non-cash income in Other Income and Expenses, net. AFUDC debt is reported as a non-cash offset to Interest Expense on the Statements of Operations. After construction is completed, Duke Energy Kentucky is permitted to recover these costs through their inclusion in rate base and the corresponding subsequent depreciation or amortization of those regulated assets.

AFUDC equity, a permanent difference for income taxes, reduces the effective tax rate when capitalized and increases the effective tax rate when depreciated or amortized. See Note 15 for additional information.

Asset Retirement Obligations

AROs are recognized for legal obligations associated with the retirement of property, plant and equipment. Substantially all AROs are related to regulated operations. When recording an ARO, the present value of the projected liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The liability is accreted over time. For operating plants, the present value of the liability is added to the cost of the associated asset and depreciated over the remaining life of the asset. For retired plants, the present value of the liability is recorded as a regulatory asset unless determined not to be probable of recovery.

The present value of the initial obligation and subsequent updates are based on discounted cash flows, which include estimates regarding timing of future cash flows, selection of discount rates and cost escalation rates, among other factors. These estimates are subject to change. Depreciation expense is adjusted prospectively for any changes to the carrying amount of the associated asset. Duke Energy Kentucky receives amounts to fund the cost of the ARO from regulated revenues. As a result, amounts recovered in regulated revenues, accretion expense and depreciation of the associated asset are netted and deferred as a regulatory asset or regulatory liability.

Obligations for closure of ash basins are based upon discounted cash flows of estimated costs for site-specific plans, if known, or probability weightings of the potential closure methods if the closure plans are under development and multiple closure options are being considered and evaluated on a site-by-site basis. See Note 6 for further information.

Accounts Payable

During 2020, Duke Energy established a supply chain finance program (the "program") with a global financial institution. Duke Energy Kentucky is a participant in this enterprise-wide program offered to suppliers. The program is voluntary and allows Duke Energy Kentucky suppliers, at their sole discretion, to sell their receivables from Duke Energy Kentucky to the financial institution at a rate that leverages Duke Energy Kentucky's credit rating and, which may result in favorable terms compared to the rate available to the supplier on their own credit rating. Suppliers participating in the program determine at their sole discretion which invoices they will sell to the financial institution. Suppliers' decisions on which invoices are sold do not impact Duke Energy Kentucky's payment terms, which are based on commercial terms negotiated between Duke Energy Kentucky and the supplier regardless of program participation. The commercial terms negotiated between Duke Energy Kentucky and its suppliers are consistent regardless of whether the supplier elects to participate in the program. Duke Energy Kentucky does not issue any guarantees with respect to the program and does not participate in negotiations between suppliers and the financial institution. Duke Energy Kentucky does not have an economic interest in the supplier's decision to participate in the program and receives no interest, fees or other benefit from the financial institution based on supplier participation in the program.

Suppliers invoices sold to the financial institution under the program totaled $0 and $1.8 million for the years ended December 31, 2021, and 2020, respectively, for Duke Energy Kentucky. All activity related to amounts due to suppliers who elected to participate in the program are included within Net cash provided by operating activities on the Statements of Cash Flows.

Revenue Recognition

Duke Energy Kentucky recognizes revenue as customers obtain control of promised goods and services in an amount that reflects consideration expected in exchange for those goods or services. Generally, the delivery of electricity and natural gas results in the transfer of control to customers at the time the commodity is delivered and the amount of revenue recognized is equal to the amount billed to each customer, including estimated volumes delivered when billings have not yet occurred. See Note 13 for further information.

Derivatives and Hedging

Derivative instruments may be used in connection with commodity price and interest rate activities, including swaps, futures, forwards and options. All derivative instruments, except those that qualify for the normal purchase/normal sale exception, are recorded on the Balance Sheets at fair value. For activity subject to regulatory accounting, gains and losses on derivative contracts are reflected as regulatory assets or regulatory liabilities and not as other comprehensive income or current period income. As a result, changes in fair value of these derivatives have no immediate earnings impact. See Note 10 for further information.

Unamortized Debt Premium, Discount and Expense

Premiums, discounts and expenses incurred with the issuance of outstanding long-term debt are amortized over the term of the debt issue. The gain or loss on extinguishment associated with refinancing higher-cost debt obligations in the regulated operations is amortized over the remaining life of the original instrument. Amortization expense is recorded as Interest Expense in the Statements of Operations and is reflected as Depreciation and amortization within Net cash provided by operating activities on the Statements of Cash Flows.
Premiums, discounts and expenses are presented as an adjustment to the carrying value of the debt amount and included in Long-Term Debt on the Balance Sheets presented.

Loss Contingencies and Environmental Liabilities

Contingent losses are recorded when it is probable a loss has occurred and can be reasonably estimated. When a range of the probable loss exists and no amount within the range is a better estimate than any other amount, the minimum amount in the range is recorded. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Environmental liabilities are recorded on an undiscounted basis when environmental remediation or other liabilities become probable and can be reasonably estimated. Environmental expenditures related to past operations that do not generate current or future revenues are expensed. Environmental expenditures related to operations that generate current or future revenues are expensed or capitalized, as appropriate. Certain environmental expenditures receive regulatory accounting treatment and are recorded as regulatory assets. See Notes 2 and 3 for further information.

Pension and Other Post-Retirement Benefit Plans

Duke Energy maintains qualified, non-qualified and other post-retirement benefit plans. Eligible employees of Duke Energy Kentucky participate in the respective qualified, non-qualified and other post-retirement benefit plans and Duke Energy Kentucky is allocated its proportionate share of benefit costs. See Note 14 for further information, including significant accounting policies associated with these plans.

Income Taxes

Duke Energy and its subsidiaries file a consolidated federal income tax return and other state and foreign jurisdictional returns. Duke Energy Kentucky has a tax-sharing agreement with Duke Energy, and income taxes recorded represent amounts Duke Energy Kentucky would incur as a separate C-Corporation. Deferred income taxes have been provided for temporary differences between GAAP and tax bases of assets and liabilities because the differences create taxable or tax-deductible amounts for future periods. Investment tax credits associated with regulated operations are deferred and amortized as a reduction of income tax expense over the estimated useful lives of the related properties.

Accumulated deferred income tax is valued using the enacted tax rate expected to apply to taxable income in the periods in which the deferred tax asset or liability is expected to be settled or realized. In the event of a change in tax rates, deferred tax assets and liabilities are remeasured as of the enactment date of the new rate. To the extent that the change in the value of the deferred tax represents an obligation to customers, the impact of the remeasurement is deferred to a regulatory liability. Remaining impacts are recorded in income from continuing operations. If Duke Energy Kentucky's estimate of the tax effect of reversing temporary differences is not reflective of actual outcomes, is modified to reflect new developments or interpretations of the tax law, is revised to incorporate new accounting principles, or changes in the expected timing or manner of the reversal then Duke Energy Kentucky's results of operations could be impacted.

Tax-related interest and penalties are recorded in Interest Expense and Other Income and Expenses, net, in the Statements of Operations. See Note 15 for further information.

Dividend Restrictions

Duke Energy Kentucky is required to pay dividends solely out of retained earnings and to maintain a minimum of 35% equity in its capital structure.

New Accounting Standards

The following new accounting standard was adopted by Duke Energy Kentucky in 2021.

Leases with Variable Lease Payments. In July 2021, the Financial Accounting Standards Board (FASB) issued new accounting guidance requiring lessors to classify a lease with variable lease payments that do not depend on a reference index or rate as an operating lease if both of the following are met: (1) the lease would have to be classified as a sales-type or direct financing lease under prior guidance, and (2) the lessor would have recognized a day-one loss. Duke Energy Kentucky elected to adopt the guidance immediately upon issuance of the new standard and will be applying the new standard prospectively to new lease arrangements meeting the criteria. Duke Energy Kentucky did not have any lease arrangements that this new accounting guidance materially impacted.

The following new accounting standard has been issued but not yet adopted by Duke Energy Kentucky as of December 31, 2021.

Reference Rate Reform. In March 2020, the FASB issued new accounting guidance for reference rate reform. This guidance is elective and provides expedients to facilitate financial reporting for the anticipated transition away from the London Inter-bank Offered Rate (LIBOR) and other interbank reference rates starting in 2021 with all rates expected to be fully phased out in 2023. The optional expedients are effective for modification of existing contracts or new arrangements executed between March 12, 2020, through December 31, 2022.

Duke Energy Kentucky has variable-rate debt and manages interest rate risk by entering into financial contracts including interest rate swaps that are generally indexed to LIBOR. Impacted financial arrangements extending beyond the phase out of the applicable LIBOR rate may require contractual amendment or termination to fully adapt to a post-LIBOR environment. Duke Energy Kentucky is assessing these financial arrangements and is evaluating the use of optional expedients outlined in the new accounting guidance. Alternative index provisions are also
being assessed and incorporated into new financial arrangements that extend beyond the phase out of the applicable LIBOR rate. The full outcome of the transition away from LIBOR cannot be determined at this time, but it is not expected to have a material impact on the financial statements.

2. REGULATORY MATTERS

REGULATORY ASSETS AND LIABILITIES

Duke Energy Kentucky records regulatory assets and liabilities that result from the ratemaking process. See Note 1 for further information.

The following table represents the regulatory assets and liabilities on the Balance Sheets.

(in thousands)	December 31, 2021	2020	Earns/Pays a Return	Recovery/Refund Period Ends
Regulatory Assets[(a)]				
East Bend deferrals	$ **36,428**	40,199	X	(c)
AROs – coal ash	**32,776**	22,208	X	(c)(g)
Accrued pension and other post-retirement benefits	**31,454**	35,714		(b)
Deferred fuel and purchased gas costs	**19,588**	—		(d)(g)2022
East Bend outage normalization	**8,309**	4,438		(c)
Demand side management/Energy efficiency costs	**4,685**	1,300		(c)(d)
Hedge costs and other deferrals	**4,220**	5,874		(e)
Advanced Metering Infrastructure	**3,498**	3,867		2033
Deferred gas integrity costs	**2,214**	2,468	X	2029
Storm cost deferrals	**2,011**	3,203		(c)
Carbon management research grant	**1,267**	1,467		2028
Vacation accrual	**1,242**	1,324		2022
Deferred debt expense	**394**	517		2036
Other	**2,111**	4,288		(c)(d)
Total regulatory assets	**150,197**	126,867		
Less: current portion	**35,031**	14,833		
Total noncurrent regulatory assets	$ **115,166**	$ 112,034		
Regulatory Liabilities[(a)]				
Net regulatory liability related to income taxes	$ **118,253**	124,395		(c)
Accrued pension and other post-retirement benefits	**6,169**	6,041		(b)
Deferred fuel and purchased gas costs	**3,699**	3,775		(d)2022
Demand side management/Energy efficiency costs	**848**	1,004		(c)(d)
Costs of removal	**747**	7,439		(f)
Other	**155**	3,309		(c)(e)
Total regulatory liabilities	**129,871**	145,963		
Less: current portion	**9,241**	11,389		
Total noncurrent regulatory liabilities	$ **120,630**	$ 134,574		

(a) Regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 14 for further information.
(c) The expected recovery or refund period varies or has not been determined.
(d) Deferred costs are recovered through a rider mechanism.
(e) Some amounts relate to unrealized gains and losses on derivatives recorded as a regulatory asset or liability, respectively, until the contracts are settled.
(f) Represents funds received from customers to cover future removal of property, plant and equipment from retired or abandoned sites as property is retired. Included in rate base and recovered over the life of associated assets.
(g) Certain amounts are recovered through rates.

RATE RELATED INFORMATION

The KPSC approves rates for retail electric and natural gas services within the Commonwealth of Kentucky. The FERC approves rates for electric sales to wholesale customers served under cost-based rates, as well as sales of transmission service.

Duke Energy Kentucky Natural Gas Base Rate Case

On June 1, 2021, Duke Energy Kentucky filed an application with the KPSC requesting an increase in natural gas base rates of approximately $15 million, an approximate 13% average increase across all customer classes. The drivers for this case are capital invested since Duke Energy Kentucky's last natural gas base rate case in 2018. Duke Energy Kentucky is also seeking implementation of a Governmental Mandate Adjustment mechanism (Rider GMA) in order to recover from or pay to customers the financial impact of governmental directives and mandates, including changes in federal or state tax rates and regulations issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA). On October 8, 2021, Duke Energy Kentucky filed a Stipulation and Recommendation jointly with the Kentucky Attorney General, subject to review and approval by the KPSC, which if approved, would resolve the case. The Stipulation and Recommendation includes a $9 million increase in base revenues, an ROE of 9.375% for natural gas base rates and 9.3% for natural gas riders, a rider for PHMSA-required capital investments with an annual 5% rate increase cap and a four-year natural gas base rate case stay-out. The evidentiary hearing was held on October 18, 2021. On December 28, 2021, the KPSC approved the Stipulation and Recommendation with minor modifications, authorizing a $9 million increase. Rates were effective January 4, 2022.

Midwest Propane Cavern

Duke Energy Kentucky uses propane stored in a cavern to meet peak demand during winter. Duke Energy Ohio is installing a new natural gas pipeline (the Central Corridor Project) in its Ohio service territory to increase system reliability and enable the retirement of older infrastructure. Once the Central Corridor Project is commercially available in March 2022, the propane peaking facility will no longer be necessary and will be retired. On October 7, 2021, and November 4, 2021, Duke Energy Ohio and Duke Energy Kentucky, respectively, filed requests with the Public Utility Commission of Ohio and the KPSC to establish a regulatory asset for their share of expenses incurred related to the retirement of the propane storage cavern and associated propane-air facilities. On January 31, 2022, the KPSC issued an order denying Duke Energy Kentucky's request. As a result of the KPSC order, Duke Energy Kentucky recorded a $0.9 million charge to Impairment of assets and other charges on Duke Energy Kentucky's Statement of Operations and Comprehensive Income in the fourth quarter of 2021. There is approximately $2.6 million and $2.5 million related to the propane caverns in Net property, plant and equipment on Duke Energy Kentucky's Balance Sheets as of December 31, 2021, and December 31, 2020, respectively.

Regional Transmission Organization Realignment

Duke Energy Kentucky transferred control of its transmission assets to effect a Regional Transmission Organization (RTO) realignment from Midcontinent Independent System Operator, Inc. (MISO) to PJM Interconnection, LLC (PJM), effective December 31, 2011.

On December 22, 2010, the KPSC approved Duke Energy Kentucky's request to effect the RTO realignment, subject to a commitment not to seek double-recovery in a future rate case of the transmission expansion fees that may be charged by MISO and PJM in the same period or overlapping periods. Duke Energy Kentucky is currently recovering PJM transmission expansion fees through current base rates.

Upon its exit from MISO on December 31, 2011, Duke Energy Kentucky recorded a liability and expense for its exit obligation and share of MISO Transmission Expansion Planning costs, excluding Multi Value Projects. This liability was recorded within Other in Current Liabilities and Other in Noncurrent Liabilities on the Balance Sheets.

The following table provides a reconciliation of the beginning and ending balance of recorded obligations related to the withdrawal from MISO.

(in thousands)	December 31, 2020	Provision / Adjustments	Cash Reductions	December 31, 2021
MISO withdrawal liability	$ 13,532	$ **268**	$ **(823)**	$ **12,977**

3. COMMITMENTS AND CONTINGENCIES

GENERAL INSURANCE

Duke Energy Kentucky has insurance and/or reinsurance coverage either directly or through indemnification from Duke Energy's captive insurance company, Bison Insurance Company Limited, and its affiliates, consistent with companies engaged in similar commercial operations with similar type properties. Duke Energy Kentucky's coverage includes (i) commercial general liability coverage for liabilities arising to third parties for bodily injury and property damage; (ii) workers' compensation; (iii) automobile liability coverage; and (iv) property coverage for all real and personal property damage. Real and personal property damage coverage excludes electric transmission and distribution lines, but includes damages arising from boiler and machinery breakdowns, earthquakes, flood damage and extra expense, but not outage or replacement power coverage. All coverage is subject to certain deductibles or retentions, sublimits, exclusions, terms and conditions common for companies with similar types of operations. Duke Energy Kentucky self-insures its electric transmission and distribution lines against loss due to storm damage and other natural disasters.

The cost of Duke Energy Kentucky's coverage can fluctuate year to year reflecting claims history and conditions of the insurance and reinsurance markets.
In the event of a loss, terms and amounts of insurance and reinsurance available might not be adequate to cover claims and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered by other sources, could have a material effect on Duke Energy Kentucky's results of operations, cash flows or financial position. Duke Energy Kentucky is responsible to the extent losses may be excluded or exceed limits of the coverage available.

ENVIRONMENTAL

Duke Energy Kentucky is subject to federal, state and local regulations regarding air and water quality, hazardous and solid waste disposal, coal ash and other environmental matters. These regulations can be changed from time to time, imposing new obligations on Duke Energy Kentucky.

Remediation Activities

In addition to the AROs discussed in Note 6, Duke Energy Kentucky is responsible for environmental remediation at various sites. These include certain properties that are part of ongoing operations and sites formerly owned or used by Duke Energy Kentucky. These sites are in various stages of investigation, remediation and monitoring. Managed in conjunction with relevant federal, state and local agencies, remediation activities vary based upon site condition and location, remediation requirements, complexity and sharing of responsibility. If remediation activities involve joint and several liability provisions, strict liability, or cost recovery or contribution actions, Duke Energy Kentucky could potentially be held responsible for environmental impacts caused by other potentially responsible parties, and may also benefit from insurance policies or contractual indemnities that cover some or all cleanup costs. Liabilities are recorded when losses become probable and are reasonably estimable. The total costs that may be incurred cannot be estimated because the extent of environmental impact, allocation among potentially responsible parties, remediation alternatives and/or regulatory decisions have not yet been determined. Additional costs associated with remediation activities are likely to be incurred in the future and could be significant. Costs are typically expensed as Operation, maintenance and other on the Statements of Operations unless regulatory recovery of the costs is deemed probable.

Duke Energy Kentucky has accrued approximately $668 thousand of probable and estimable costs related to its various environmental sites in Other within Other Noncurrent Liabilities on the Balance Sheets as of December 31, 2021, and 2020. Additional losses in excess of recorded reserves are expected to be immaterial for the stages of investigation, remediation and monitoring for the environmental sites that have been evaluated. The maximum amount of the range for all stages of Duke Energy Kentucky's environmental sites cannot be determined at this time.

LITIGATION

Duke Energy Kentucky is involved in other legal, tax and regulatory proceedings arising in the ordinary course of business, some of which involve significant amounts. Duke Energy Kentucky believes the final disposition of these proceedings will not have a material effect on its results of operations, cash flows or financial position. Duke Energy Kentucky expenses legal costs related to the defense of loss contingencies as incurred.

OTHER COMMITMENTS AND CONTINGENCIES

General

As part of its normal business, Duke Energy Kentucky is party to various financial guarantees, performance guarantees and other contractual commitments to extend guarantees of credit and other assistance to various third parties. These guarantees involve elements of performance and credit risk, which are not included on the Balance Sheets. The possibility of Duke Energy Kentucky having to honor its contingencies is largely dependent upon future operations of various third parties or the occurrence of certain future events.

Purchase Obligations

Pipeline and Storage Capacity Contracts

Duke Energy Kentucky enters into pipeline and storage capacity contracts that commit future cash flows to acquire services needed in its business. Costs arising from capacity commitments are recovered via the Gas Cost Adjustment Clause in Kentucky. The time period for fixed payments under these pipeline and storage capacity contracts is up to five years.

Certain storage and pipeline capacity contracts require the payment of demand charges that are based on rates approved by the FERC in order to maintain rights to access the natural gas storage or pipeline capacity on a firm basis during the contract term. The demand charges that are incurred in each period are recognized in the Statements of Operations as part of natural gas purchases and are included in Cost of natural gas.

The following table presents future unconditional purchase obligations under these contracts.

(in thousands)		December 31, 2021
2022	$	9,314
2023		8,347
2024		8,185
2025		2,566
2026		394
Thereafter		—
Total	$	28,806

4. LEASES

As part of its operations, Duke Energy Kentucky leases space on communication towers, meters and office space under various terms and expiration dates. Certain Duke Energy Kentucky lease agreements include options for renewal and early termination. The intent to renew a lease varies depending on the lease type and asset. Renewal options that are reasonably certain to be exercised are included in the lease measurements. The decision to terminate a lease early is dependent on various economic factors. No termination options have been included in any of the lease measurements.

Duke Energy Kentucky has certain lease agreements, which include variable lease payments that are based on the usage of an asset. These variable lease payments are not included in the measurement of the ROU assets or operating lease liabilities on the Balance Sheets.

The following table presents the components of lease expense and are included in Operations, maintenance and other on the Statements of Operations.

	Years Ended December 31,			
(in thousands)		2021		2020
Operating lease expense	$	1,801	$	1,846
Short-term lease expense		1		—
Variable lease expense		51		66
Total lease expense	$	1,853	$	1,912

The following table presents operating lease maturities and a reconciliation of the undiscounted cash flows to operating lease liabilities.

(in thousands)		December 31, 2021
2022	$	688
2023		700

2024		712
2025		725
2026		739
Thereafter		8,627
Total operating lease payments		12,191
Less: present value discount		(3,495)
Total operating lease liabilities[(a)]	$	8,696

(a) Certain operating lease payments include renewal options that are reasonably certain to be exercised.

The following tables contain additional information related to leases.

		December 31,	
(in thousands)	Classification	2021	2020
Assets			
Operating	Operating lease ROU assets, net	$ 8,407	$ 8,786
Total lease assets		$ 8,407	$ 8,786
Liabilities			
Current			
Operating	Other current liabilities	$ 318	$ 293
Noncurrent			
Operating	Operating lease liabilities	8,379	8,696
Total lease liabilities		$ 8,697	$ 8,989

	Years ended December 31,	
(in thousands)	2021	2020
Cash paid for amounts included in the measurement of lease liabilities[(a)]		
Operating cash flows from operating leases	$ 676	$ 665

(a) No amounts were classified as investing cash flows from operating leases for the years ended December 31, 2021, and 2020.

	December 31,	
	2021	2020
Weighted-average remaining lease term (years)		
Operating leases	16	17
Weighted-average discount rate[(a)]		
Operating leases	4.4 %	4.4 %

(a) The discount rate is calculated using the rate implicit in a lease if it is readily determinable. Generally, the rate used by the lessor is not provided to Duke Energy Kentucky and in these cases the incremental borrowing rate is used. Duke Energy Kentucky will typically use its fully collateralized incremental borrowing rate as of the commencement date to calculate and record the lease. The incremental borrowing rate is influenced by the lessee's credit rating and lease term and as such may differ for individual leases, embedded leases or portfolios of leased assets.

5. DEBT AND CREDIT FACILITIES

SUMMARY OF DEBT AND RELATED TERMS

The following table summarizes outstanding debt.

			December 31,	
(in thousands)	Weighted Average Interest Rate	Year Due	2021	2020
Unsecured debt	3.77	2023 - 2057	$ 680,000	$ 630,000
Tax-exempt bonds[(a)(b)]	0.12	2027	26,720	76,720
Money pool borrowings[(b)(c)]	0.36	2026	127,596	100,472
Unamortized debt discount and premium, net			(174)	(186)
Unamortized debt issuance costs			(2,325)	(2,738)
Total debt	3.13		$ 831,817	$ 804,268
Short-term money pool borrowings			(102,596)	(75,472)
Current maturities of long-term debt			—	(50,000)
Total long-term debt			$ 729,221	$ 678,796

(a) Includes $27 million that is secured by a bilateral letter of credit agreement at December 31, 2021, and 2020.
(b) Floating-rate debt. At December 31, 2020, the weighted average interest rate was 0.75% and 0.41% for tax-exempt bonds and money pool borrowings, respectively.
(c) Includes $25 million classified as Long-Term Debt Payable to Affiliated Companies on the Balance Sheets at December 31, 2021, and 2020.

MATURITIES AND CALL OPTIONS

The following table shows the annual maturities of long-term debt for the next five years and thereafter. Amounts presented exclude short-term notes payable.

(in thousands)	December 31, 2021
2022	$ —
2023	75,000
2024	—
2025	95,000
2026	70,000
Thereafter	491,720
Total long-term debt, including current maturities	$ 731,720

Duke Energy Kentucky has the ability under certain debt facilities to call and repay the obligation prior to its scheduled maturity. Therefore, the actual timing of future cash repayments could be materially different than as presented above.

SHORT-TERM OBLIGATIONS CLASSIFIED AS LONG-TERM DEBT

Certain tax-exempt bonds that may be put to Duke Energy Kentucky at the option of the holder and money pool borrowings, which are short-term obligations by nature, are classified as long-term due to Duke Energy Kentucky's intent and ability to utilize such borrowings as long-term financing. As Duke Energy's Master Credit Facility and Duke Energy Kentucky's other bilateral letter of credit agreements have non-cancelable terms in excess of one year as of the balance sheet date, Duke Energy Kentucky has the ability to refinance these short-term obligations on a long-term basis. See "Available Credit Facilities" below for additional information.

At December 31, 2021, and 2020, $27 million of tax-exempt bonds and $25 million of money pool borrowings were classified as Long-Term Debt and Long-Term Debt Payable to Affiliated Companies, respectively, on the Balance Sheets.

SUMMARY OF SIGNIFICANT DEBT ISSUANCES

In 2020, Duke Energy Kentucky issued $70 million of unsecured debt, of which $35 million carry a fixed interest rate of 2.65% and mature September 2030, and $35 million carry a fixed interest rate of 3.66% and mature September 2050. The proceeds were used to pay down short-term debt and for general corporate purposes.

AVAILABLE CREDIT FACILITIES

Master Credit Facility

In March 2021, Duke Energy amended its existing $8 billion Master Credit Facility to extend the termination date to March 2026. Duke Energy Kentucky has borrowing capacity under the Master Credit Facility up to a specified sublimit. Duke Energy has the unilateral ability at any time to increase or decrease Duke Energy Kentucky's borrowing sublimit, subject to a maximum sublimit. The amount available to Duke Energy Kentucky under the Master Credit Facility may be reduced to backstop issuances of commercial paper, certain letters of credit and variable-rate demand tax-exempt bonds that may be put to Duke Energy Kentucky at the option of the holder. At December 31, 2021, Duke Energy Kentucky had a borrowing sublimit of $175 million and available capacity of $56 million under the Master Credit Facility.

Duke Energy Kentucky and Duke Energy Indiana, LLC, a subsidiary of Duke Energy, collectively have a $156 million bilateral letter of credit agreement. In February 2018, the bilateral letter of credit agreement was amended to extend the termination date from February 2019 to February 2023. Duke Energy Kentucky may request the issuance of letters of credit up to $27 million on its behalf to support various series of tax-exempt bonds. This credit facility may not be used for any purpose other than to support the tax-exempt bonds.

Term Loan Facility

In October 2021, Duke Energy Kentucky entered into a two-year term loan facility with commitments totaling $50 million. Borrowings under the facility will be used to pay down short-term debt and for general corporate purposes. The term loan was fully drawn at the time of closing in October. The balance is classified as Long-Term Debt on Duke Energy Kentucky's Balance Sheet.

OTHER DEBT MATTERS

Money Pool

Duke Energy Kentucky receives support for its short-term borrowing needs through participation with Duke Energy and certain of its subsidiaries in a money pool arrangement. Under this arrangement, those companies with short-term funds may provide short-term loans to affiliates participating under this arrangement. The money pool is structured such that Duke Energy Kentucky separately manages its cash needs and working capital requirements. Accordingly, there is no net settlement of receivables and payables between money pool participants. Duke Energy may loan funds to its participating subsidiaries, but may not borrow funds through the money pool.

Money pool receivable balances are reflected within Notes receivable from affiliated companies on the Balance Sheets. Money pool payable balances are reflected within either Notes payable to affiliated companies or Long-Term Debt Payable to Affiliated Companies on the Balance Sheets.

Restrictive Debt Covenants

Duke Energy Kentucky's debt and credit agreements contain various financial and other covenants. Duke Energy's Master Credit Facility contains a covenant requiring the debt-to-total capitalization ratio not to exceed 65% for each borrower. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of December 31, 2021, Duke Energy Kentucky was in compliance with all covenants related to its debt agreements. In addition, some credit agreements may allow for acceleration of payments or termination of the agreements due to nonpayment, or acceleration of other significant indebtedness of the borrower or some of its subsidiaries. None of the debt or credit agreements contain material adverse change clauses.

6. ASSET RETIREMENT OBLIGATIONS

Duke Energy Kentucky records an ARO when it has a legal obligation to incur retirement costs associated with the retirement of a long-lived asset and the obligation can be reasonably estimated. Certain assets have an indeterminate life, and thus the fair value of the retirement obligation is not reasonably estimable. A liability for these AROs will be recorded when a fair value is determinable. Duke Energy Kentucky's regulated electric and regulated natural gas operations accrue costs of removal for property that does not have an associated legal retirement obligation based on regulatory orders from the KPSC. These costs of removal are recorded as a regulatory liability in accordance with regulatory accounting treatment. See Note 2 for the estimated cost of removal for assets without an associated legal retirement obligation, which are included in Regulatory liabilities on the Balance Sheets as of December 31, 2021, and 2020.

Duke Energy Kentucky is subject to state and federal regulations covering the closure of coal ash impoundments, including the EPA Coal Combustion Residuals (CCR) Rule. AROs recorded on the Balance Sheets include the legal obligation for the disposal of CCR, which is based upon estimated closure costs for impacted ash impoundments. The amount recorded represents the discounted cash flows for estimated closure costs based upon specific closure plans. Actual costs to be incurred will be dependent upon factors that vary from site to site. The most significant factors are the method and time frame of closure at the individual sites. Closure methods considered include removing the water from ash basins, consolidating material as necessary and capping the ash with a synthetic barrier, excavating and relocating the ash to a lined structural fill or lined landfill or recycling the ash for concrete or some other beneficial use. The ultimate method and timetable for closure will be in compliance with standards set by federal and state regulations and other agreements. The ARO amount will be adjusted as additional information is gained through the closure and post-closure process, including acceptance and approval of compliance approaches, which may change management assumptions, and may result in a material change to the balance. Asset retirement costs associated with coal ash AROs at the East Bend Station are included within Property, Plant and Equipment on the Balance Sheets.

In addition to the coal ash AROs, Duke Energy Kentucky also has legal obligations related to the retirement of gas mains and asbestos remediation.

The following table presents the changes in the liability associated with AROs.

	Years Ended December 31,	
(in thousands)	**2021**	**2020**
Balance at beginning of period	**$ 76,112**	$ 49,780
Accretion expense[(a)]	**2,518**	1,898
Liabilities settled	**(2,761)**	(1,949)
Revisions to estimates of cash flows[(b)]	**17,413**	26,383
Balance at end of period	**$ 93,282**	$ 76,112

(a) All accretion expense for the years ended December 31, 2021, and 2020, relates to Duke Energy Kentucky's regulated operations and has been deferred in accordance with regulatory accounting treatment.
(b) Amounts primarily relate to changes in maintenance and landfill closure cost estimates for ash impoundments.

7. PROPERTY, PLANT AND EQUIPMENT

The following table summarizes property, plant and equipment.

	Average Remaining Useful Life	December 31,	
(in thousands)	**(Years)**	**2021**	**2020**
Land		**$ 41,365**	$ 36,925
Plant			
Electric generation, distribution and transmission	**47**	**2,073,113**	2,015,291
Natural gas transmission and distribution	**49**	**757,878**	701,175

Other buildings and improvements	61	14,197	13,018
Equipment	13	**36,869**	38,269
Construction in process		**97,535**	71,664
Other	13	**60,455**	68,031
Total property, plant and equipment		**3,081,412**	2,944,373
Accumulated depreciation and amortization		**(1,063,561)**	(1,030,627)
Facilities to be retired, net		**1,769**	—
Net property, plant and equipment[(a)]		**$ 2,019,620**	$ 1,913,746

(a) The debt component of AFUDC totaled $450 thousand and $0 at December 31, 2021, and 2020, respectively.

8. OTHER INCOME AND EXPENSES, NET

The components of Other Income and Expenses, net on the Statements of Operations are as follows.

	Years Ended December 31,	
(in thousands)	**2021**	**2020**
Income/(Expense):		
Interest income	**$ 982**	$ 965
AFUDC equity	**1,260**	(124)
Other	**2,612**	1,951
Other Income and Expenses, net	**$ 4,854**	$ 2,792

9. RELATED PARTY TRANSACTIONS

Duke Energy Kentucky engages in related party transactions, which are generally performed at cost and in accordance with KPSC and FERC regulations. Refer to the Balance Sheets for balances due to or from related parties. Material amounts related to transactions with related parties included in the Statements of Operations are presented in the following table.

	Years Ended December 31,	
(in thousands)	**2021**	**2020**
Corporate governance and shared service expenses[(a)]	**$ 83,976**	$ 86,038

(a) Duke Energy Kentucky is charged its proportionate share of costs, primarily related to human resources, employee benefits, information technology, legal and accounting fees, as well as other third-party costs, from a consolidated affiliate of Duke Energy. These amounts are recorded in Operation, maintenance and other within Operating Expenses on the Statements of Operations.

In addition to the amounts presented above, Duke Energy Kentucky has other affiliate transactions, including certain indemnification coverages through Duke Energy's wholly owned captive insurance subsidiary, rental of office space, participation in a money pool arrangement with Duke Energy and certain of its subsidiaries, other operational transactions and its proportionate share of certain charged expenses. See Note 5 for more information regarding the money pool.

Certain trade receivables have been sold by Duke Energy Kentucky to CRC, an unconsolidated entity formed by a subsidiary of Duke Energy. The proceeds obtained from the sales of receivables are largely cash but do include a subordinated note from CRC for a portion of the purchase price. See Note 12 for further information related to the sales of these receivables.

Intercompany Income Taxes

Duke Energy and its subsidiaries file a consolidated federal income tax return and other state and jurisdictional returns. Duke Energy Kentucky has a tax sharing agreement with Duke Energy for the allocation of consolidated tax liabilities and benefits. Income taxes recorded represent amounts Duke Energy Kentucky would incur as a separate C-Corporation. Duke Energy Kentucky had an intercompany tax receivable balance of $9 million at December 31, 2021, and an intercompany tax payable balance of $2 million at December 31, 2020.

10. DERIVATIVES AND HEDGING

COMMODITY PRICE RISK

Duke Energy Kentucky has limited exposure to market price changes of fuel and emission allowance costs incurred for its retail customers due to the use of cost tracking and recovery mechanisms. Duke Energy Kentucky does have exposure to the impact of market fluctuations in the prices of electricity, fuel and emission allowances associated with its generation output not utilized to serve retail operations or committed load (off-system, wholesale power sales). Duke Energy Kentucky's outstanding commodity derivatives, FTRs, had a notional volume of 1,681 gigawatt-hours and 2,559 gigawatt-hours at December 31, 2021, and 2020, respectively.

See Note 11 for additional information on the fair value of commodity derivatives.

INTEREST RATE RISK

Duke Energy Kentucky is exposed to changes in interest rates as a result of its issuance or anticipated issuance of variable-rate and fixed-rate debt. Interest rate risk is managed by limiting variable-rate exposure to a percentage of total debt and by monitoring changes in interest rates. To manage risk associated with changes in interest rates, Duke Energy Kentucky may enter into financial contracts including interest rate swaps and U.S. Treasury lock agreements. The notional amount of interest rate swaps outstanding was $26.7 million at December 31, 2021, and 2020. Financial contracts entered into by Duke Energy Kentucky are not designated as a hedge because they are accounted for under regulatory accounting. With regulatory accounting, the mark-to-market gains or losses are deferred as regulatory liabilities or assets, respectively. Regulatory assets and regulatory liabilities are amortized consistent with the treatment of related costs in the ratemaking process. The accrual of interest on swaps is recorded as Interest Expense on the Statements of Operations.

See Note 11 for additional information on the fair value of interest rate derivatives.

CREDIT RISK
Duke Energy Kentucky analyzes the financial condition of counterparties prior to entering into agreements and establishes credit limits and monitors the appropriateness of those limits on an ongoing basis. Credit limits and collateral requirements for retail electric customers are established by the KPSC.

Duke Energy Kentucky's industry has historically operated under negotiated credit lines for physical delivery contracts. Duke Energy Kentucky may use master collateral agreements to mitigate certain credit exposures. The collateral agreements require certain counterparties to post cash or letters of credit for the amount of exposure in excess of an established threshold. The threshold amount represents an unsecured credit limit determined in accordance with the corporate credit policy. Collateral agreements also provide that the inability to post collateral is sufficient cause to terminate contracts and liquidate all positions.

Duke Energy Kentucky also obtains cash or letters of credit from customers to provide credit support outside of collateral agreements, where appropriate, based on its financial analysis of the customer and the regulatory or contractual terms and conditions applicable to each transaction.

11. FAIR VALUE MEASUREMENTS

Fair value is the exchange price to sell an asset or transfer a liability in an orderly transaction between market participants at the measurement date. The fair value definition focuses on an exit price versus the acquisition cost. Fair value measurements use market data or assumptions market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs may be readily observable, corroborated by market data or generally unobservable. Valuation techniques maximize the use of observable inputs and minimize use of unobservable inputs. A midmarket pricing convention (the midpoint price between bid and ask prices) is permitted for use as a practical expedient. Fair value measurements are classified in three levels based on the fair value hierarchy as defined by GAAP.

Fair value accounting guidance permits entities to elect to measure certain financial instruments that are not required to be accounted for at fair value, such as equity method investments or the company's own debt, at fair value. Duke Energy Kentucky has not elected to record any of these items at fair value.

Commodity derivatives

If forward price curves are not observable for the full term of the contract and the unobservable period had more than an insignificant impact on the valuation, the commodity derivative is classified as Level 3. The valuation technique and unobservable input for an FTR is regional transmission organization auction pricing and FTR price - per megawatt-hour, respectively.

Interest rate derivatives

All over-the-counter interest rate contract derivatives are valued using financial models that utilize observable inputs for similar instruments and are classified as Level 2. Inputs include forward interest rate curves, notional amounts, interest rates and credit quality of the counterparties.

QUANTITATIVE DISCLOSURES

The following tables provide recorded balances for assets and liabilities measured at fair value on a recurring basis on the Balance Sheets. Derivative amounts in the table below exclude cash collateral.

	December 31, 2021					
(in thousands)		**Total Fair Value**		**Level 2**		**Level 3**
Derivative assets[a]	**$**	**1,636**	**$**	**—**	**$**	**1,636**
Derivative liabilities[b]		**(4,645)**		**(4,645)**		**—**
Net (liabilities) asset	**$**	**(3,009)**	**$**	**(4,645)**	**$**	**1,636**

	December 31, 2020					
(in thousands)		**Total Fair Value**		**Level 2**		**Level 3**
Derivative assets[a]	$	1,380	$	—	$	1,380
Derivative liabilities[b]		(6,299)		(6,299)		—
Net (liabilities) assets	$	(4,919)	$	(6,299)	$	1,380

(a) Included in Other within Current Assets and Other within Other Noncurrent Assets on the Balance Sheets. The amounts classified as Level 3 relate to FTRs.
(b) Included in Other within Current Liabilities and Other within Other Noncurrent Liabilities on the Balance Sheets. The amounts classified as Level 2 relate to interest rate swaps.
The following table provides a reconciliation of beginning and ending balances of assets and liabilities measured at fair value on a recurring basis where the determination of fair value includes significant unobservable inputs (Level 3).

	Derivatives (net) Years Ended December 31,			
(in thousands)		**2021**		**2020**
Balance at beginning of period	**$**	**1,380**	$	3,507
Purchases, sales, issuances and settlements:				
Purchases		**3,332**		3,601
Settlements		**(3,419)**		(5,750)
Total gains included on the Balance Sheets as regulatory assets or liabilities		**343**		22
Balance at end of period	**$**	**1,636**	$	1,380

OTHER FAIR VALUE DISCLOSURES

The fair value of long-term debt, including current maturities, is summarized in the following table. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates determined are not necessarily indicative of the amounts Duke Energy Kentucky could have settled in current markets. The fair value of long-term debt is determined using Level 2 measurements.

	December 31, 2021				December 31, 2020			
(in thousands)		**Book value**		**Fair value**		**Book value**		**Fair value**
Long-Term debt, including current maturities	**$**	**729,221**	**$**	**793,431**	$	728,796	$	810,738

At December 31, 2021, and 2020, the fair value of cash and cash equivalents, accounts and notes receivable, and accounts and notes payable are not materially different from their carrying amounts because of the short-term nature of these instruments and/or because the stated rates approximate market rates.

12. VARIABLE INTEREST ENTITIES

A variable interest entity (VIE) is an entity that is evaluated for consolidation using more than a simple analysis of voting control. The analysis to determine whether an entity is a VIE considers contracts with an entity, credit support for an entity, the adequacy of the equity investment of an entity and the relationship of voting power to the amount of equity invested in an entity. This analysis is performed either upon the creation of a legal entity or upon the occurrence of an event requiring reevaluation, such as a significant change in an entity's assets or activities. A qualitative analysis of control determines the party that consolidates a VIE. This assessment is based on (i) what party has the power to direct the activities of the VIE that most significantly impact its economic performance and (ii) what party has rights to receive benefits or is obligated to absorb losses that could potentially be significant to the VIE. The analysis of the party that consolidates a VIE is a continual reassessment.

Cinergy Receivables Company

CRC is a bankruptcy remote, special purpose entity that is an affiliate of Duke Energy Kentucky. As discussed below, Duke Energy Kentucky does not consolidate CRC as it is not the primary beneficiary. On a revolving basis, CRC buys certain accounts receivable arising from the sale of electricity, natural gas and related services from Duke Energy Kentucky. CRC borrows amounts under a credit facility to buy the receivables from Duke Energy Kentucky. Borrowing availability from the credit facility is limited to the amount of qualified receivables sold to CRC which generally exclude receivables past due more than a predetermined number of days and reserves for expected past due balances. The sole source of funds to satisfy the related debt obligation is cash collections from the receivables. Amounts borrowed under the credit facility are reflected on the Balance Sheets as Long-Term Debt.

The proceeds Duke Energy Kentucky receives from the sale of receivables to CRC are approximately 75% cash and 25% in the form of a subordinated note from CRC. The subordinated note is a retained interest in the receivables sold. Duke Energy Kentucky had receivables of $22.4 million and $21.0 million from CRC at December 31, 2021, and 2020, respectively. These balances are included in Receivables from affiliated companies on the Balance Sheets and reflect Duke Energy Kentucky's retained interest in receivables sold to CRC.

CRC is considered a VIE because (i) equity capitalization is insufficient to support its operations, (ii) power to direct the activities that most significantly impact the economic performance of the entity is not held by the equity holder and (iii) deficiencies in net worth of CRC are funded by Duke Energy. The most significant activities that impact the economic performance of CRC are decisions made to manage delinquent receivables. Duke Energy is considered the primary beneficiary and consolidates CRC as it makes these decisions. Duke Energy Kentucky does not consolidate CRC.

The subordinated note held by Duke Energy Kentucky is stated at fair value. Carrying values of retained interests are determined by allocating carrying value of the receivables between assets sold and interests retained based on relative fair value. The allocated basis of the subordinated note is not materially different than the face value because (i) the receivables generally turnover in less than two months, (ii) credit losses are reasonably predictable due to the broad customer base and lack of significant concentration and (iii) the equity in CRC is subordinate to all retained interests and thus would absorb losses first. The hypothetical effect on fair value of the retained interests assuming both a 10% and a 20% unfavorable variation in credit losses or discount rates is not material due to the short turnover of receivables and historically low credit loss history. Interest accrues to Duke Energy Kentucky on the retained interests using the acceptable yield method. This method generally approximates the stated rate on the note since the allocated basis and the face value are nearly equivalent. An impairment charge is recorded against the carrying value of both retained interests and purchased beneficial interest whenever it is determined that an other-than-temporary impairment has occurred. Duke Energy Kentucky's maximum exposure to loss does not exceed the carrying value.

Key assumptions used in estimating fair value are detailed in the following table.

	2021	2020

Anticipated credit loss ratio	0.4 %	0.4 %
Discount rate	1.1 %	1.6 %
Receivables turnover rate	11.4 %	11.3 %

The following table presents gross and net receivables sold.

	December 31,	
(in thousands)	2021	2020
Receivables sold	$ 76,127	$ 66,298
Less: Retained interests	22,397	21,031
Net receivables sold	$ 53,730	$ 45,267

The following table shows sales and cash flows related to receivables sold.

	Years Ended December 31,	
(in thousands)	2021	2020
Sales		
Receivables sold	$ 516,369	$ 456,902
Loss recognized on sale	1,657	1,427
Cash flows		
Cash proceeds from receivables sold	$ 513,346	$ 450,487
Collection fees received	258	228
Return received on retained interests	976	937

Cash flows from sales of receivables are reflected within Cash Flows from Operating Activities and Cash Flows from Investing Activities on the Statements of Cash Flows.

Collection fees received in connection with the servicing of transferred accounts receivable are included in Operation, maintenance and other on the Statements of Operations. The loss recognized on sales of receivables is calculated monthly by multiplying receivables sold during the month by the required discount. The required discount is derived monthly utilizing a three-year weighted average formula that considers charge-off history, late charge history and turnover history on the sold receivables, as well as a component for the time value of money. The discount rate, or component for the time value of money, is the prior month-end London Interbank Offered Rate plus a fixed rate of 1.00%.

13. REVENUE

Duke Energy Kentucky recognizes revenue consistent with amounts billed under tariff offerings or at contractually agreed upon rates based on actual physical delivery of electric or natural gas service, including estimated volumes delivered when billings have not yet occurred. As such, the majority of Duke Energy Kentucky's revenues have fixed pricing based on the contractual terms of the published tariffs, with variability in expected cash flows attributable to the customer's volumetric demand and ultimate quantities of energy or natural gas supplied and used during the billing period. The stand-alone selling price of related sales are designed to support recovery of prudently incurred costs and an appropriate return on invested assets and are primarily governed by published tariff rates or contractual agreements approved by relevant regulatory bodies. Certain excise taxes and franchise fees levied by state or local governments are required to be paid even if not collected from the customer. These taxes are recognized on a gross basis as part of revenues. Duke Energy Kentucky elects to account for all other taxes net of revenues.

Performance obligations are satisfied over time as energy or natural gas is delivered and consumed with billings generally occurring monthly and related payments due within 30 days, depending on regulatory requirements. In no event does the timing between payment and delivery of the goods and services exceed one year. Using this output method for revenue recognition provides a faithful depiction of the transfer of electric and natural gas service as customers obtain control of the commodity and benefit from its use at delivery. Additionally, Duke Energy Kentucky has an enforceable right to consideration for energy or natural gas delivered at any discrete point in time and will recognize revenue at an amount that reflects the consideration to which Duke Energy Kentucky is entitled for the energy or natural gas delivered.
As described above, the majority of Duke Energy Kentucky's tariff revenues are at-will and, as such, related contracts with customers have an expected duration of one year or less and will not have future performance obligations for disclosure.

Duke Energy Kentucky earns substantially all of its revenues through the sale of electricity and natural gas.

Electricity Sales

Electric sales revenues are earned primarily through retail and wholesale electric service through the generation, transmission, distribution and sale of electricity. Duke Energy Kentucky generally provides retail electric service customers with their full electric load requirements and sells wholesale block sales of electricity into the market.

Retail electric service is generally marketed throughout Duke Energy Kentucky's electric service territory through standard service offers. The standard service offers are through tariffs determined by the KPSC. Each tariff, which is assigned to customers based on customer class, has multiple components such as an energy charge, customer charge, demand charge and applicable riders. Duke Energy Kentucky considers each of these components to be aggregated into a single performance obligation for providing electric service. Electricity is considered a single performance obligation satisfied over time consistent with the series guidance and is provided and consumed over the billing period, generally one month. Retail electric service is typically provided to at-will customers who can cancel service at any time, without a substantive penalty. Additionally, Duke Energy Kentucky adheres to applicable regulatory requirements to ensure the collectability of amounts billed and appropriate mitigating procedures are followed when necessary. As such, revenue from contracts with customers is equivalent to the electricity supplied and billed in that period (including unbilled estimates).

Wholesale electric service is provided through block sales of electricity. Revenues for block sales are recognized monthly as energy is delivered and stand-ready service is provided, consistent with invoiced amounts and unbilled estimates.

Natural Gas Sales

Natural gas sales revenues are earned through retail natural gas service through the transportation, distribution and sale of natural gas. Duke Energy Kentucky generally provides natural gas service customers with all natural gas load requirements. Additionally, while natural gas can be stored, substantially all natural gas provided by Duke Energy Kentucky is consumed by customers simultaneously with receipt of delivery.

Retail natural gas service is marketed throughout Duke Energy Kentucky's natural gas service territory using published tariff rates. The tariff rates are established by the KPSC. Each tariff, which is assigned to customers based on customer class, has multiple components, such as a commodity charge, customer or monthly charge and transportation costs. Duke Energy Kentucky considers each of these components to be aggregated into a single performance obligation for providing natural gas service. For contracts where Duke Energy Kentucky provides all of the customer's natural gas needs, the delivery of natural gas is considered a single performance obligation satisfied over time, and revenue is recognized monthly based on billings and unbilled estimates as service is provided and the commodity is consumed over the billing period. Additionally, natural gas service is typically at-will and customers can cancel service at any time, without a substantive penalty. Duke Energy Kentucky also adheres to applicable regulatory requirements to ensure the collectability of amounts billed and receivable and appropriate mitigating procedures are followed when necessary.

Disaggregated Revenues

For electric and natural gas sales, revenue by customer class is most meaningful to Duke Energy Kentucky as each respective customer class collectively represents unique customer expectations of service, generally has different energy and demand requirements and operates under tailored, regulatory approved pricing structures. Additionally, each customer class is impacted differently by weather and a variety of economic factors including the level of population growth, economic investment, employment levels and regulatory activities. As such, analyzing revenues disaggregated by customer class allows Duke Energy Kentucky to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

Disaggregated revenues are presented as follows:

(in thousands)	Years Ended December 31,	
By market or type of customer	2021	2020
Electricity Sales		
Residential	$ 158,494	$ 136,723
General	154,570	139,705
Industrial	59,299	55,875
Wholesale[(a)]	15,523	9,044
Other revenues	10,384	5,956

Total Electricity Sales revenue from contracts with customers	$	398,270	$	347,303
Natural Gas Sales				
Residential	$	75,340	$	65,941
Commercial		32,142		25,570
Industrial		5,249		4,449
Other revenues		2,890		2,814
Total Natural Gas Sales revenue from contracts with customers	$	115,621	$	98,774
Total revenue from contracts with customers	$	513,891	$	446,077
Other revenue sources[b]	$	6,301		5,689
Total revenues	$	520,192	$	451,766

(a) Duke Energy Kentucky nets wholesale electric sales and purchases on an hourly basis. As such, the net position may result in fluctuations between positive and negative net revenues at the end of a reporting period.
(b) Other revenue sources include revenues from derivatives, leases and alternative revenue programs that are not considered revenues from contracts with customers.

As described in Note 1, Duke Energy Kentucky adopted the new guidance for credit losses effective January 1, 2020, using the modified retrospective method of adoption, which does not require restatement of prior year reported results. The following table presents the reserve for credit losses for trade and other receivables based on adoption of the new standard.

(in thousands)		
Balance at December 31, 2019	$	314
Write-offs		(373)
Credit Loss Expense		383
Balance at December 31, 2020	**$**	**324**
Write-offs		**(7)**
Credit Loss Expense		**(2)**
Balance at December 31, 2021	**$**	**315**

Trade and other receivables are evaluated based on an estimate of the risk of loss over the life of the receivable and current and historical conditions using supportable assumptions. Management evaluates the risk of loss for trade and other receivables by comparing the historical write-off amounts to total revenue over a specified period. Historical loss rates are adjusted due to the impact of current conditions, including the impacts of COVID-19, as well as forecasted conditions over a reasonable time period. The calculated write-off rate can be applied to the receivable balance for which an established reserve does not already exist. Management reviews the assumptions and risk of loss periodically for trade and other receivables.

The aging of trade receivables is presented in the table below. Duke Energy Kentucky considers receivables greater than 30 days outstanding past due.

		December 31,		
(in thousands)		**2021**		**2020**
Unbilled Receivables[a][b]	$	**326**	$	779
0-30 days		**2,346**		4,094
30-60 days		**177**		330
60-90 days		**34**		59
90+ days		**5,069**		3,395
Deferred Payment Arrangements[c]		**21**		—
Trade and Other Receivables	**$**	**7,973**	**$**	**8,657**

(a) Unbilled revenues are recognized by applying customer billing rates to the estimated volumes of energy or natural gas delivered but not yet billed and are included in Receivables on the Duke Energy Kentucky Balance Sheets. Unbilled receivables relate to transactions with PJM.
(b) Duke Energy Kentucky sells, on a revolving basis, nearly all of its retail accounts receivable, including receivables for unbilled revenues, to CRC. As discussed further in Note 8, Duke Energy Kentucky accounts for these transfers of receivables as sales. Accordingly, the receivables sold are not reflected on the Balance Sheets. Receivables for unbilled revenues included in the sales of accounts receivable to CRC were $27 million and $23 million at December 31, 2021, and 2020, respectively.
(c) Due to certain customer financial hardships created by the COVID-19 pandemic and resulting stay-at-home orders, Duke Energy Kentucky permitted customers to defer payment of past-due amounts through an installment payment plan over a period of several months.

14. EMPLOYEE BENEFIT PLANS

DEFINED BENEFIT RETIREMENT PLANS

Duke Energy Kentucky participates in qualified and non-qualified defined benefit retirement plans and other post-retirement benefit plans sponsored by Duke Energy. Duke Energy allocates pension and other post-retirement obligations and costs related to these plans to Duke Energy Kentucky. The plans cover most employees using a cash balance formula. Under a cash balance formula, a plan participant accumulates a retirement benefit consisting of pay credits based upon a percentage of current eligible earnings based on age and/or years of service and interest credits. Certain employees are covered under plans that use a final average earnings formula. Under these average earnings formulas, a plan participant accumulates a retirement benefit equal to the sum of percentages of their (i) highest three-year or four-year average earnings, (ii) highest three-year or four-year average earnings in excess of covered compensation per year of participation (maximum of 35 years) and/or (iii) highest three-year average earnings times years of participation in excess of 35 years. Duke Energy also maintains, and Duke Energy Kentucky participates in, non-qualified, non-contributory defined benefit retirement plans which cover certain executives. The qualified and non-qualified non-contributory defined benefit plans are closed to new participants.

Duke Energy uses a December 31 measurement date for its defined benefit retirement plan assets and obligations. Actuarial losses experienced by the defined benefit retirement plans in remeasuring plan assets as of December 31, 2021, were primarily attributable to actual investment performance that was less than expected investment performance. Actuarial gains experienced by the defined benefit retirement plans in remeasuring plan obligations as of December 31, 2021, were primarily attributable to the increase in the discount rate used to measure plan obligations. Actuarial gains experienced by the defined benefit retirement plans in remeasuring plan assets as of December 31, 2020, were attributable to actual investment performance that exceeded expected investment performance. Actuarial losses experienced by the defined benefit retirement plans in remeasuring plan obligations as of December 31, 2020, were primarily attributable to the decrease in the discount rate used to measure plan obligations.

Duke Energy's policy is to fund amounts on an actuarial basis to provide assets sufficient to meet benefit payments to be paid to plan participants. Duke Energy Kentucky did not make any contributions in 2021. Duke Energy Kentucky does not anticipate making any contributions in 2022.

Net periodic benefit costs disclosed in the tables below represent the cost of the respective plan for the periods presented prior to capitalization of amounts reflected as Net property, plant and equipment, on the Balance Sheets. Only the service cost component of net periodic benefit costs is eligible to be capitalized. The remaining non-capitalized portions of net periodic benefit costs are classified as either: (i) service cost, which is recorded in Operations, maintenance and other on the Statements of Operations; or as (ii) components of non-service cost, which is recorded in Other income and expenses, net, on the Statements of Operations. Amounts presented in the tables below represent the amounts of pension and other post-retirement benefit cost allocated by Duke Energy for employees of Duke Energy Kentucky. Additionally, Duke Energy Kentucky is allocated its proportionate share of pension and other post-retirement benefit cost for employees of Duke Energy's shared services affiliate that provides support to Duke Energy Kentucky. These allocated amounts are included in the governance and shared services costs discussed in Note 9.

QUALIFIED PENSION PLANS

Components of Net Periodic Pension Costs

		Years Ended December 31,		
(in thousands)		**2021**		**2020**
Service cost	$	**1,212**	$	1,179
Interest cost on projected benefit obligation		**3,031**		3,761
Expected return on plan assets		**(6,207)**		(6,539)
Amortization of prior service credit		**(95)**		(98)
Amortization of actuarial loss		**2,118**		1,965

Amortization of settlement charges		—		350
Net periodic pension costs	$	59	$	618

Amounts Recognized in Regulatory Assets

		December 31,		
(in thousands)		**2021**		**2020**
Regulatory assets, net (decrease)	**$**	**(4,069)**	$	(127)

Reconciliation of Funded Status to Net Amount Recognized

		Years Ended December 31,		
(in thousands)		**2021**		**2020**
Change in Projected Benefit Obligation				
Obligation at prior measurement date	**$**	**120,132**	$	117,086
Service cost		**1,124**		1,082
Interest cost		**3,031**		3,761
Actuarial (gains) losses		**(1,741)**		6,427
Transfers [(a)]		**(2,943)**		—
Benefits paid		**(15,153)**		(8,224)
Obligation at measurement date	**$**	**104,450**	$	120,132
Accumulated Benefit Obligation at measurement date	**$**	**101,920**	$	118,545
Change in Fair Value of Plan Assets				
Plan assets at prior measurement date	**$**	**106,173**	$	103,267
Actual return on plan assets		**5,577**		11,130
Benefits paid		**(15,153)**		(8,224)
Employer contributions		**—**		—
Transfers [(a)]		**(2,943)**		—
Plan assets at measurement date	**$**	**93,654**	$	106,173
Funded status of plan	**$**	**(10,796)**	$	(13,959)

(a) Transfers represents net amounts associated with plan participants that have moved to/from other Duke Energy subsidiaries.

Amounts Recognized in the Balance Sheets

		December 31,		
(in thousands)		**2021**		**2020**
Prefunded pension[(a)]	**$**	**16,381**	$	12,852
Noncurrent pension liability[(b)]		**27,177**		26,811
Net liability recognized	**$**	**(10,796)**	$	(13,959)
Regulatory assets	**$**	**29,961**	$	34,030

(a) Included in Other within Investments and Other Assets on the Balance Sheets.
(b) Included in Accrued pension and other post-retirement benefit costs on the Balance Sheets.

Information for Plans with Accumulated Benefit Obligation in Excess of Plan Assets

		December 31,		
(in thousands)		**2021**		**2020**
Projected benefit obligation	**$**	**41,707**	$	53,559
Accumulated benefit obligation		**39,177**		51,971
Fair value of plan assets		**14,530**		26,748

Assumptions Used for Pension Benefits Accounting

	December 31,	
	2021	**2020**
Benefit Obligations		
Discount rate	**2.90 %**	2.60 %
Interest crediting rate	**4.00 %**	4.00 %
Salary increase	**3.50 %**	3.50 %
Net Periodic Benefit Cost		
Discount rate	**2.60 %**	3.30 %
Interest crediting rate	**4.00 %**	4.00 %
Salary increase	**3.50 %**	3.50 %
Expected long-term rate of return on plan assets	**6.50 %**	6.85 %

The discount rate used to determine the current year pension obligation and following year's pension expense is based on a bond selection-settlement portfolio approach. This approach develops a discount rate by selecting a portfolio of high quality corporate bonds that generate sufficient cash flow to provide for the projected benefit payments of the plan. The selected bond portfolio is derived from a universe of non-callable corporate bonds rated Aa quality or higher. After the bond portfolio is selected, a single interest rate is determined that equates the present value of the plan's projected benefit payments discounted at this rate with the market value of the bonds selected.

NON-QUALIFIED PENSION PLANS

The accumulated benefit obligation, which equals the projected benefit obligation for non-qualified pension plans, was $77 thousand for Duke Energy Kentucky as of December 31, 2021. Employer contributions, which equal benefits paid for non-qualified pension plans, were not material for the year ended December 31, 2021. Net periodic pension costs for non-qualified pension plans were not material for the years ended

December 31, 2021, or 2020.

OTHER POST-RETIREMENT BENEFIT PLANS

Duke Energy provides, and Duke Energy Kentucky participates in, some health care and life insurance benefits for retired employees on a contributory and non-contributory basis. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans. The health care benefits include medical, dental and prescription drug coverage and are subject to certain limitations, such as deductibles and co-payments.

Duke Energy did not make any pre-funding contributions to its other post-retirement benefit plans during the years ended December 31, 2021, and 2020.

Components of Net Periodic Other Post-Retirement Benefit Costs

	Years Ended December 31,	
(in thousands)	**2021**	**2020**
Service cost	$ **81**	$ 133
Interest cost on projected benefit obligation	**112**	174
Expected return on plan assets	**(67)**	(77)
Amortization of prior service credit	**(220)**	(236)
Amortization of actuarial loss	**214**	231
Net periodic post-retirement pension costs	$ **120**	$ 225

Amounts Recognized in Regulatory Assets and Regulatory Liabilities

	December 31,	
(in thousands)	**2021**	**2020**
Regulatory assets, net decrease	$ **(187)**	$ (209)
Regulatory liabilities, net increase	**(128)**	(712)

Reconciliation of Funded Status to Accrued Other Post-Retirement Benefit Costs

	Years Ended December 31,	
(in thousands)	**2021**	**2020**
Change in Projected Benefit Obligation		
Accumulated post-retirement benefit obligation at prior measurement date	$ **4,619**	$ 5,596
Service cost	**81**	133
Interest cost	**112**	174
Plan participants' contributions	**179**	187
Actuarial gains	**(284)**	(820)
Benefits paid	**(513)**	(651)
Accrued retiree drug subsidy	**—**	—
Accumulated post-retirement benefit obligation at measurement date	$ **4,194**	$ 4,619
Change in Fair Value of Plan Assets		
Plan assets at prior measurement date	$ **1,750**	$ 1,562
Actual return on plan assets	**104**	184
Plan participants' contributions	**179**	187
Benefits paid	**(513)**	(651)
Employer contributions	**55**	468
Plan assets at measurement date	$ **1,575**	$ 1,750
Funded status of plan	$ **(2,619)**	$ (2,869)

Amounts Recognized in the Balance Sheets

	December 31,	
(in thousands)	**2021**	**2020**
Current post-retirement liability[(a)]	$ **168**	$ 156
Noncurrent post-retirement liability[(b)]	**2,451**	2,713
Total accrued post-retirement liability	$ **2,619**	$ 2,869
Regulatory assets	$ **1,447**	$ 1,634
Regulatory liabilities	$ **6,169**	$ 6,041

(a) Included in Other within Current Liabilities on the Balance Sheets.
(b) Included in Accrued pension and other post-retirement benefit costs on the Balance Sheets.

Assumptions Used for Other Post-Retirement Benefits Accounting

	December 31,	
	2021	**2020**
Benefit Obligations		
Discount rate	**2.90 %**	2.60 %
Net Periodic Benefit Cost		
Discount rate	**2.60 %**	3.30 %
Expected long-term rate of return on plan assets	**6.50 %**	6.85 %

The discount rate used to determine the current year other post-retirement benefits obligation and following year’s other post-retirement benefits expense is based on a bond selection-settlement portfolio approach. This approach develops a discount rate by selecting a portfolio of high quality corporate bonds that generate sufficient cash flow to provide for the projected benefit payments of the plan. The selected bond portfolio is derived from a universe of non-callable corporate bonds rated Aa quality or higher. After the bond portfolio is selected, a single interest rate is determined that equates the present value of the plan's projected benefit payments discounted at this rate with the market value of the bonds selected.

Assumed Health Care Cost Trend Rate

	December 31, 2021	2020
Health care cost trend rate assumed for next year	**6.25 %**	6.25 %
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	**4.75 %**	4.75 %
Year that the rate reaches the ultimate trend rate	**2028**	2028

Expected Benefit Payments

The following table presents Duke Energy's expected benefit payments to participants on behalf of Duke Energy Kentucky in its qualified and other post-retirement benefit plans over the next 10 years. These benefit payments reflect expected future service, as appropriate.

(in thousands)	Qualified Plans	Other Post-Retirement Plans	Total
Years ending December 31,			
2022	$ 7,877	$ 765	$ 8,642
2023	7,812	537	8,349
2024	7,862	424	8,286
2025	7,566	369	7,935
2026	7,468	320	7,788
2027–2031	35,351	1,206	36,557

MASTER RETIREMENT TRUST

The assets for the Duke Energy Kentucky plans discussed above are derived from the Master Retirement Trust (Master Trust) that is held by Duke Energy and, as such, Duke Energy Kentucky is allocated its proportionate share of assets discussed below. Assets for both the qualified pension and other post-retirement benefits are maintained in the Master Trust. Duke Energy also invests other post-retirement assets in Voluntary Employees' Beneficiary Association trusts. The investment objective is to achieve sufficient returns, subject to a prudent level of portfolio risk, for the purpose of promoting the security of plan benefits for participants. As of December 31, 2021, Duke Energy assumes pension and other post-retirement plan assets will generate a long-term rate of return of 6.50%. The expected long-term rate of return was developed using a weighted average calculation of expected returns based primarily on future expected returns across asset classes considering the use of active asset managers, where applicable. The asset allocation targets were set after considering the investment objective and the risk profile. Equity securities are held for their high expected return. Debt securities are primarily held to hedge the qualified pension plan liability. Return seeking debt securities, hedge funds and other global securities are held for diversification. Investments within asset classes are diversified to achieve broad market participation and reduce the impact of individual managers or investments.

Effective January 1, 2022, the target asset allocation for the Duke Energy Retirement Master Trust is 60% liability hedging assets and 40% return-seeking assets. Duke Energy periodically reviews its asset allocation targets, and over time, as the funded status of the benefit plans increase, the level of asset risk relative to plan liabilities may be reduced to better manage Duke Energy's benefit plan liabilities and reduce funded status volatility.

The following table presents target and actual asset allocations for the Master Trust at December 31, 2021, and 2020.

Asset Category	Target Allocation	Actual Allocation at December 31, 2021	2020
Global equity securities	27 %	**24 %**	30 %
Global private equity securities	1 %	**1 %**	1 %
Debt securities	62 %	**62 %**	55 %
Return seeking debt securities	4 %	**4 %**	5 %
Hedge funds	2 %	**3 %**	3 %
Real estate and cash	4 %	**6 %**	6 %
Total	100 %	**100 %**	100 %

EMPLOYEE SAVINGS PLAN

Duke Energy Kentucky also participates in employee savings plans sponsored by Duke Energy. Most employees participate in a matching contribution formula where Duke Energy provides a matching contribution generally equal to 100% of employee before-tax and Roth 401(k) contributions and, as applicable, after-tax contributions of up to 6% of eligible pay per period.

For new and rehired non-union and certain unionized employees who are not eligible to participate in Duke Energy's defined benefit plans, an additional employer contribution of 4% of eligible pay per pay period, which is subject to a three-year vesting schedule, is provided to the employee's savings plan account.

Duke Energy Kentucky's expense related to its proportionate share of pretax employer contributions and the additional 4% employer contribution was $1,215 thousand and $1,225 thousand for the years ended December 31, 2021, and 2020, respectively.

15. INCOME TAXES

INCOME TAX EXPENSE

Components of Income Tax Expense

(in thousands)	Years Ended December 31, 2021	2020
Current income taxes		
Federal	**$ (6,954)**	$ 4,226
State	**(2,229)**	816
Total current income taxes	**(9,183)**	5,042
Deferred income taxes		
Federal	**14,419**	3,005
State	**4,892**	1,722
Total deferred income taxes[a]	**19,311**	4,727

Investment tax credit amortization		(58)		(61)
Total income tax expense included in Statements of Operations	$	10,070	$	9,708

(a) Total deferred income taxes includes utilization of NOL carryforwards and tax credit carryforwards of $3 million.

Statutory Rate Reconciliation
The following table presents a reconciliation of income tax expense at the U.S. federal statutory tax rate to actual tax expense.

	Years Ended December 31,			
(in thousands)		**2021**		**2020**
Income tax expense, computed at the statutory rate of 21%	$	13,328	$	12,149
State income tax, net of federal income tax effect		2,104		2,007
Amortization of excess deferred income tax		(4,741)		(4,213)
Tax Credits		(313)		(272)
Other items, net		(308)		37
Total income tax expense	$	10,070	$	9,708
Effective tax rate		15.9 %		16.8 %

DEFERRED TAXES

Net Deferred Income Tax Liability Components

	Years Ended December 31,			
(in thousands)		**2021**		**2020**
Deferred credits and other liabilities	$	—	$	213
Lease obligations		2,141		2,190
Tax credits and NOL carryforwards		5,069		8,135
Pension, post-retirement and other employee benefits		4,387		5,414
Regulatory liabilities and deferred credits		—		5,228
Investments and other liabilities		467		921
Other		468		1,713
Total deferred income tax assets		12,532		23,814
Accelerated depreciation rates		(278,714)		(266,186)
Regulatory assets and deferred credits		(1,777)		—
Total deferred income tax liabilities		(280,491)		(266,186)
Net deferred income tax liabilities	$	(267,959)	$	(242,372)

The following table presents the expiration of tax credits and NOL carryforwards.

	December 31, 2021				
(in thousands)		**Amount**	**Expiration Year**		
General business credits	$	5,034	2024	—	2041
State NOL carryforwards		35		2037	
Total tax credits and NOL carryforwards	$	5,069			

UNRECOGNIZED TAX BENEFITS

The following table presents changes to unrecognized tax benefits.

	Years Ended December 31,			
(in thousands)		**2021**		**2020**
Unrecognized tax benefits – January 1	$	434	$	405
Unrecognized tax benefit increases		40		29
Total changes		40		29
Unrecognized tax benefits – December 31	$	474	$	434

The following table includes additional information regarding the unrecognized tax benefits at December 31, 2021. Duke Energy Kentucky does not expect a decrease in unrecognized tax benefits within the next 12 months.

(in thousands)		**December 31, 2021**
Amount that if recognized, would affect the effective tax rate or regulatory liability[(a)]	$	474

(a) Duke Energy Kentucky is unable to estimate the specific amounts that would affect the effective tax rate versus the regulatory liability.

OTHER TAX MATTERS

Duke Energy Kentucky recognized no interest income, interest expense or penalties related to income taxes on the Statements of Operations in 2021, or 2020. As of December 31, 2021, and 2020, no amounts were recognized on the Balance Sheets for interest or penalties related to income taxes.
Duke Energy Kentucky is no longer subject to U.S. federal examination for years before 2016. With few exceptions, Duke Energy Kentucky is no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2016

16. SUBSEQUENT EVENTS

Subsequent events were evaluated through March 11, 2022. For information on subsequent events related to regulatory matters, see Note 2.

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year									
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income									
3	Preceding Quarter/Year to Date Changes in Fair Value									
4	Total (lines 2 and 3)								48,143,296	48,143,296
5	Balance of Account 219 at End of Preceding Quarter/Year									
6	Balance of Account 219 at Beginning of Current Year									
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income									
8	Current Quarter/Year to Date Changes in Fair Value									
9	Total (lines 7 and 8)								53,405,580	53,405,580
10	Balance of Account 219 at End of Current Quarter/Year									

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

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

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

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	2,725,733,301	1,979,969,128	701,052,507				44,711,666
4	Property Under Capital Leases	8,407,255	[a]8,407,255					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	262,180,076	161,292,168	100,742,819				145,089
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	2,996,320,632	2,149,668,551	801,795,326				44,856,755
9	Leased to Others							
10	Held for Future Use	30,100	30,100					
11	Construction Work in Progress	96,259,188	76,095,968	18,084,206				2,079,014
12	Acquisition Adjustments							
13	Total Utility Plant (8 thru 12)	3,092,609,920	2,225,794,619	819,879,532				46,935,769
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	1,073,764,061	840,267,458	203,850,237				29,646,366
15	Net Utility Plant (13 less 14)	2,018,845,859	1,385,527,161	616,029,295				17,289,403
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	1,024,293,348	825,981,502	191,069,135				7,242,711
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	49,470,713	14,285,956	12,781,102				22,403,655

22	Total in Service (18 thru 21)	1,073,764,061	840,267,458	203,850,237				29,646,366
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation							
29	Amortization							
30	Total Held for Future Use (28 & 29)							
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment							
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,073,764,061	840,267,458	203,850,237				29,646,366

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: UtilityPlantInServicePropertyUnderCapitalLeases
Property Under Capital Leases includes Net Operating Leases of $8,407,255.

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication					
3	Nuclear Materials					
4	Allowance for Funds Used during Construction					
5	(Other Overhead Construction Costs, provide details in footnote)					
6	SUBTOTAL (Total 2 thru 5)					
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)					
9	In Reactor (120.3)					
10	SUBTOTAL (Total 8 & 9)					
11	Spent Nuclear Fuel (120.4)					
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)					
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)					
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ 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 the 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) 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.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization						
3	(302) Franchise and Consents						
4	(303) Miscellaneous Intangible Plant	26,954,689	1,814,693	8,134,813		107,296	20,741,865
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	26,954,689	1,814,693	8,134,813		107,296	20,741,865
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	7,046,984					7,046,984
9	(311) Structures and Improvements	183,857,575	1,789,190	1,929,127			183,717,638
10	(312) Boiler Plant Equipment	543,068,511	13,735,475	3,451,672			553,352,314
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	107,549,781	1,375,409	(360,601)			109,285,791
13	(315) Accessory Electric Equipment	48,089,323	104,796	20,769			48,173,350
14	(316) Misc. Power Plant Equipment	24,161,752	79,503	244,149			23,997,106
15	(317) Asset Retirement Costs for Steam Production	85,162,356	15,539,087				100,701,443
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	998,936,282	32,623,460	5,285,116			1,026,274,626
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	3,035,570					3,035,570
38	(341) Structures and Improvements	36,643,814	(266,829)	(2,275)			36,379,260
39	(342) Fuel Holders, Products, and Accessories	61,174,734	124,228	(11,928)			61,310,890
40	(343) Prime Movers	13,452,726	1,206,004	4,318,021			10,340,709
41	(344) Generators	218,755,648	2,443,300	136,717			221,062,231
42	(345) Accessory Electric Equipment	20,962,535	719,223	205,897			21,475,861
43	(346) Misc. Power Plant Equipment	4,948,600	187,555	(15,955)			5,152,110
44	(347) Asset Retirement Costs for Other Production						
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	358,973,627	4,413,481	4,630,477			358,756,631
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,357,909,909	37,036,941	9,915,593			1,385,031,257

47	3. Transmission Plant						
48	(350) Land and Land Rights	1,568,803	1,820,147				3,388,950
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	5,869,397	116,143				5,985,540
50	(353) Station Equipment	57,749,062	1,517,157	830,743			58,435,476
51	(354) Towers and Fixtures						
52	(355) Poles and Fixtures	20,075,968	1,328,620	6,139,085			15,265,503
53	(356) Overhead Conductors and Devices	9,136,564	4,180,736	427,100			12,890,200
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)	94,399,794	8,962,803	7,396,928			95,965,669
59	4. Distribution Plant						
60	(360) Land and Land Rights	17,076,806	15,178				17,091,984
61	(361) Structures and Improvements	1,420,206					1,420,206
62	(362) Station Equipment	112,285,658	8,235,081	3,525,487			116,995,252
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	72,966,758	2,072,455	557,177			74,482,036
65	(365) Overhead Conductors and Devices	141,144,880	11,805,214	882,256			152,067,838
66	(366) Underground Conduit	41,176,284	2,214,962	18,702			43,372,544
67	(367) Underground Conductors and Devices	75,463,130	6,777,393	369,942			81,870,581
68	(368) Line Transformers	68,583,503	6,538,569	1,106,632			74,015,440
69	(369) Services	23,636,085	(1,397,549)	8,289			22,230,247
70	(370) Meters	28,291,526	295,177	51,852			28,534,851
71	(371) Installations on Customer Premises	566,262	314,117	18,043			862,336
72	(372) Leased Property on Customer Premises	9,647					9,647
73	(373) Street Lighting and Signal Systems	9,095,631	915,992	277,219			9,734,404
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	591,716,376	37,786,589	6,815,599			622,687,366

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						
87	(390) Structures and Improvements	178,336	(13,000)	(6)			165,342
88	(391) Office Furniture and Equipment	3,414,512	153,419	399,954			3,167,977
89	(392) Transportation Equipment	1,332,863	(1,643)				1,331,220
90	(393) Stores Equipment						
91	(394) Tools, Shop and Garage Equipment	2,873,594	288,079				3,161,673
92	(395) Laboratory Equipment						
93	(396) Power Operated Equipment	11,770					11,770
94	(397) Communication Equipment	8,867,252	284,679	154,775			8,997,156
95	(398) Miscellaneous Equipment	(7,561)	7,561				
96	SUBTOTAL (Enter Total of lines 86 thru 95)	16,670,766	719,095	554,723			16,835,138
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)	16,670,766	719,095	554,723			16,835,138
100	TOTAL (Accounts 101 and 106)	2,087,651,534	86,320,121	32,817,656		107,296	2,141,261,295
101	(102) Electric Plant Purchased (See Instr. 8)						
102	(Less) (102) Electric Plant Sold (See Instr. 8)						
103	(103) Experimental Plant Unclassified						
104		2,087,651,534	[(a)]86,320,121	32,817,656		107,296	2,141,261,295

	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)						

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: ElectricPlantInServiceAdditions

The balances above do not include Operating Lease Activity

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
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41						
42						
43						
44						
45						
46						
47	TOTAL					

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				

24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
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39				
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41				
42				
43				
44				
45				
46				
47	TOTAL			

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	DISTRIBUTION PLANT	
2	DISTRIBUTION OVERHEAD/UNDERGROUND LINE IMPROVEMENTS	3,818,108
3	DEK AERO SOLAR	3,456,752
4	AERO SUBSTATION DISTRIBUTION EXITS	1,780,747
5	EMERGENT - BELLEVUE SUBSTATION REPLACEMENT	1,056,699
6	PROJECTS LESS THAN $1 MILLION	4,635,935
7	GENERAL PLANT	
8	DEK TOWERS, SHELTERS & POWER SUPPLIES	2,767,534
9	IT KENTUCKY PROJECTS	2,428,777
10	DEK MICROWAVE	1,903,505
11	PROJECTS LESS THAN $1 MILLION	3,058,677
12	INTANGIBLE PLANT	
13	CUSTOMER CONNECT FUNDING PROJECT	5,119,660
14	SMART GRID DEE DMS ADMS - 336	1,439,842
15	DEE SCADA DMS UPGRADE	1,144,219
16	PROJECTS LESS THAN $1 MILLION	2,331,359
17	PRODUCTION PLANT	
18	GENERATOR STATOR REWIND	13,615,700
19	EVERGREEN UPGRADE	4,774,857
20	LPA AND LPB L-2 BLADE REPLACEMENT	4,011,485
21	PROJECTS LESS THAN $1 MILLION	1,496,113
22	TRANSMISSION PLANT	
23	ERECT 138 KV LINE FROM WOODSPOINT SUBSTATION TO AERO SUBSTATION	15,749,780

24	PROJECTS LESS THAN $1 MILLION	1,506,219
43	Total	76,095,968

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

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

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 12, column (c), and that reported for electric plant in service, page 204, column (d), 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.

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)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	801,887,395	801,887,395		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	48,640,753	48,640,753		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	102,373	102,373		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):				
9.2	EastBend Depreciation	(490,618)	(490,618)		
9.3	Common Plant Depreciation	47,864	47,864		
9.4	ARO Depreciation deferred	11,718,431	11,718,431		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	60,018,803	60,018,803		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(24,282,888)	[a](24,282,888)		
13	Cost of Removal	(11,889,071)	(11,889,071)		
14	Salvage (Credit)	282,236	282,236		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(35,889,723)	(35,889,723)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):				

17.2	Other Cost of Removal/Salvage Activity	(46,818)	(46,818)		
17.3	Reserve Transfer from Intangible Plant	11,845	11,845		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	825,981,502	825,981,502		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	471,148,901	471,148,901		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	190,442,460	190,442,460		
25	Transmission	10,382,698	10,382,698		
26	Distribution	150,530,889	150,530,889		
27	Regional Transmission and Market Operation				
28	General	3,476,554	3,476,554		
29	TOTAL (Enter Total of lines 20 thru 28)	825,981,502	825,981,502		

FOOTNOTE DATA

(a) Concept: BookCostOfRetiredPlant

Intangible Retirements of $8,134,813 and General Plant Assets Retirements of $399,954 not reported on FERC Page 219.

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder the information called for below. Sub-TOTAL by company and give a TOTAL in columns (e), (f), (g) and (h). (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1								
2								
3								
4								
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7								
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37								
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39								
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41								
42	Total Cost of Account 123.1 $		Total					

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ 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)	30,021,194	32,848,807	Gas and 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)	[a]1,778,519	[b]6,399,020	Gas and Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	15,615,600	10,094,202	Electric
8	Transmission Plant (Estimated)	1,728	101	Electric
9	Distribution Plant (Estimated)	180,260	213,994	Gas and Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	17,576,107	16,707,317	
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)	84,712	(22,522)	Gas and Electric
17				
18				
19				
20	TOTAL Materials and Supplies	47,682,013	49,533,602	

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesConstruction
Production 1,223,041Transmission 3,715Distribution 551,763
(b) Concept: PlantMaterialsAndOperatingSuppliesConstruction
Production 5,817,184Transmission 302Distribution 581,534

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ 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.
6. Report on Line 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 acquired 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 and 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.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
1	Balance-Beginning of Year	[a]212,008	16,593	29,387		29,387		29,387		676,107		976,276	16,593
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
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	3,896	176									3,896	176

19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total	3,896	176									3,896	176
29	Balance-End of Year	[(b)]208,112	16,417	29,387		29,387		29,387		676,107		972,380	16,417
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	279		279		279		279		13,671		14,787	
37	Add: Withheld by EPA									279		279	
38	Deduct: Returned by EPA												
39	Cost of Sales												
40	Balance-End of Year	279		279		279		279		13,950		15,066	
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: AllowanceInventoryNumber
Balances includes allowances for Cross State Air Pollution Rule and the Acid Rain Program.
(b) Concept: AllowanceInventoryNumber
Balances includes allowances for Cross State Air Pollution Rule and the Acid Rain Program.

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ 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.
6. Report on Line 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 acquired 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 and 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.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
1	Balance-Beginning of Year	[a]14,492	3,328	3,292		3,292		3,292				24,368	3,328
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
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	2,471	557									2,471	557
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total	2,471	557									2,471	557
29	Balance-End of Year	[(b)] 12,021	2,771	3,292		3,292		3,292				21,897	2,771
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: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: AllowanceInventoryNumber
Balances includes allowances for Cross State Air Pollution Rule only.
(b) Concept: AllowanceInventoryNumber
Balances includes allowances for Cross State Air Pollution Rule only.

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
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10						
11						
12						
13						
14						
15						
16						
17						
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21						
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23						

24						
25						
26						
27						
28						
20	TOTAL					

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of COmmission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
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40						
41						
42						
43						

44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20	Total				

21	**Generation Studies**				
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39	Total				
40	Grand Total				

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ 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 Quarter/Year Account Charged (d)	CREDITS: Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	INCOME TAXES	5,667,313		282, 283	38,172	5,629,141
2	DEMAND SIDE MANAGEMENT COSTS - (Amortized in accordance with rider revenue) - Order #2017-321, Order #2015-368, Order #2014-388	1,300,207	3,384,549			4,684,756
3	INTEREST RATE HEDGES (Amortized over life associated debt) - Order #2006-563	5,290,232	(1,596,353)			3,693,879
4	ESM DEFERRAL - Order #2017-321	4,130,216	(1,946,504)			2,183,712
5	FTR DEFERRAL					
6	REPS INCREMENTAL COSTS	(829)	829			
7	ARO OTHER REGULATORY ASSET	275,020	1,636			276,656
8	GAS ARO OTHER REGULATORY ASSET	6,401,669	508,617			6,910,286
9	ARO CONTRA-REGULATORY ASSET - Order #2017-321	(718,030)	(270,029)			(988,059)
10	COAL ASH DEFERRED SPEND - Order #2015-187	974,145	108,551			1,082,696
11	COAL ASH ARO - Order #2015-187	7,640,207	11,044,537			18,684,744
12	COAL ASH CONTRA EQUITY - Order #2017-321	(713,899)	94,620			(619,279)
13	SPEND RA AMORTIZATION (NC & MW) - Order #2017-321	13,589,245		182.3, 407.3, 421, 431	1,391,902	12,197,343
14	SPEND RA AMORTIZATION (SC & FL) - Order #2017-321	718,674	2,315,895	407.3	1,603,757	1,430,812
15	DEK DEFERRED STORM EXPENSE - Order #2018-416	910,913		593	210,211	700,702
16	CARBON MANAGEMENT REGULATORY ASSET (Amortized 120 months, beginning May 2018) -Order#2017-321- Order#2008-308	1,466,637		407.3	199,996	1,266,641
17	HURRICANE IKE REGULATORY ASSET (Amortized 60 months, beginning May 2018) Order #2017-321, Order #2008-476	2,292,584		407.3	982,536	1,310,048
18	EAST BEND PLANT O&M DEFERRAL (Amortized 120 months, beginning May 2018) Order #2017-321, Order #2014-201	30,000,243		407.3, 407.4	3,280,670	26,719,573

19	EAST BEND DEPRECIATION DEFERRAL (Amortized over remaining life of asset) Order#2015-120	10,198,885		403	490,618	9,708,267
20	Non-AMI Meter NBV (Amortized 146 months, beginning May 2018) Order #2017-321	3,867,037		407.3, 421	368,588	3,498,449
21	Opt-Out IT Modification (Amortized 60 months, beginning May 2018) Order #2017-321, Order #2016-152	73,360		407.3	31,440	41,920
22	Plant Outage Normalization Order - #2017-321	4,438,156	3,871,108			8,309,264
23	Deferred Forced Outage Purchased Power Order #2017-321		83,791			83,791
24	GAS RATE CASE DEFERRAL (Amortized 60 months, beginning April 2019) - Order #2018-261	165,852		928	51,031	114,821
25	DEFERRED GAS INTEGRITY COSTS (Amortized 120 months, beginning April 2018) Order #2018-261, Order #2016-159	2,468,113		407.3, 407.4	254,153	2,213,960
26	OTHER REGULATORY ASSETS - GENERAL ACCOUNTING - FERC Docket No. A107-1-000	30,464,476		128, 182.3, 228, 253, 254, 926	3,902,544	26,561,932
27	PENSION POST RETIRE PURCHASE ACCOUNTING - Q - FERC Docket No. A107-1-000	3,565,128	39,355	128, 182.3, 228, 926	205,044	3,399,439
28	PENSION POST RETIRE PURCHASE ACCOUNTING - NQ - FERC Docket No. A107-1-000	50,426		128, 182.3, 228, 253, 254, 926	4,334	46,092
29	PENSION POST RETIRE PURCHASE ACCOUNTING - FAS - FERC Docket No. A107-1-000	1,634,422		228, 254, 926	187,536	1,446,886
30	Misc. ST Reg Assets		44,939			44,939
44	TOTAL	136,150,402	17,685,541		13,202,532	140,633,411

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ 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		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	Vacation accrual	1,324,241	(81,762)			1,242,479
2	Straight Line Lease Deferral - amortized 01/20 - 12/38	203,748	761,352	242	676,033	289,067
3	DEK 2017 Rate Case - amortized 05/18 - 04/23	341,859		928	85,465	256,394
4	DEK 2019 Rate Case - Electric - amortized 05/20 - 04/25	293,946		928	67,834	226,112
5	DEK 2021 Rate Case - Gas - amortized 01/22 - 12/27		145,139			145,139
6	Indirect overhead allocation pool - Undistributed	(7,654)	64,152			56,498
47	Miscellaneous Work in Progress					
48	Deferred Regulatroy Comm. Expenses (See pages 350 - 351)					
49	TOTAL	2,156,140				2,215,689

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ 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 at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Electric	55,843,006	53,751,239
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	55,843,006	53,751,239
9	Gas		
10		17,377,717	16,970,885
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	17,377,717	16,970,885
17.1	Other (Specify)		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	73,220,723	70,722,124

Notes

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2	Common Stock	1,000,000	15.00		585,333	8,779,995				
7	Total	1,000,000			585,333	8,779,995				
8	Preferred Stock (Account 204)									
9										
10										
11										
12	Total									
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										
5	Total									

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Other Paid-in Capital

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

Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	148,811,383
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	148,811,383
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	74,843,806
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	[a]50,000,000
16	Ending Balance Amount	124,843,806
17	**Historical Data - Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	273,655,189

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FOOTNOTE DATA

(a) Concept: IncreasesDecreasesDueToMiscellaneousPaidInCapital

Equity infusion of $50M is from the Parent.

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

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

1. Report by Balance Sheet Account the details concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt.
2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (b) include the related account number.
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received, and in column (b) include the related account number.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column (b) include the related account number.
5. In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a)principal advanced during year (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (m). Explain in a footnote any difference between the total of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1	Bonds (Account 221)												
2													
3													
4													
5	Subtotal												
6	Reacquired Bonds (Account 222)												
7													
8													
9													
10	Subtotal												
11	Advances from Associated Companies (Account 223)												
12	[(a)] Intercompany Moneypool Notes Payable-Long Term, .235%		25,000,000					12/15/2014	03/16/2026	12/15/2014	03/16/2026	25,000,000	141,453
13	Subtotal		25,000,000									25,000,000	141,453

14	Other Long Term Debt (Account 224)												
15	6.20% SERIES DUE IN 2036		65,000,000		653,550		367,900	03/07/2006	03/10/2036	03/07/2006	03/10/2036	65,000,000	4,030,000
16	[b] 2008 SERIES POLLUTION CONTROL REFUNDING BONDS DUE IN 2027		50,000,000		691,754			12/11/2008	11/01/2021	12/11/2008	11/01/2021		465,900
17	[c] 2010 SERIES A POLLUTION CONTROL REFUNDING BONDS DUE IN 2027, .120%		26,720,000		939,966			11/24/2010	08/01/2027	11/24/2010	08/01/2027	26,720,000	44,655
18	[d] TERM LOAN DUE IN 2023, .650%		50,000,000					10/12/2021	10/12/2023	10/12/2021	10/12/2023	50,000,000	73,029
19	3.42% SERIES DUE IN 2026		45,000,000		220,191			01/05/2016	01/15/2026	01/05/2016	01/15/2026	45,000,000	1,539,000
20	4.45% SERIES DUE IN 2046		50,000,000		247,535			01/05/2016	01/15/2046	01/05/2016	01/15/2046	50,000,000	2,225,000
21	3.35% SERIES DUE IN 2029		30,000,000		124,475			09/07/2017	09/15/2029	09/07/2017	09/15/2029	30,000,000	1,005,000
22	4.11% SERIES DUE IN 2047		30,000,000		124,475			09/07/2017	09/15/2047	09/07/2017	09/15/2047	30,000,000	1,233,000
23	4.26% SERIES DUE IN 2057		30,000,000		124,475			09/07/2017	09/15/2057	09/07/2017	09/15/2057	30,000,000	1,278,000
24	4.01% SERIES DUE IN 2023		25,000,000		111,522			10/03/2018	10/15/2023	10/03/2018	10/15/2023	25,000,000	1,002,500
25	4.18% SERIES DUE IN 2028		40,000,000		156,522			10/03/2018	10/15/2028	10/03/2018	10/15/2028	40,000,000	1,672,000
26	4.62% SERIES DUE IN 2048		35,000,000		141,522			12/12/2018	12/15/2048	12/12/2018	12/15/2048	35,000,000	1,617,000
27	4.32% SERIES DUE IN 2049		40,000,000		195,082			07/17/2019	07/15/2049	07/17/2019	07/15/2049	40,000,000	1,728,000
28	3.23% SERIES DUE IN 2025		95,000,000		415,082			09/26/2019	10/01/2025	09/26/2019	10/01/2025	95,000,000	3,068,500
29	3.56% SERIES DUE IN 2029		75,000,000		335,082			09/26/2019	10/01/2029	09/26/2019	10/01/2029	75,000,000	2,670,000
30	2.65% SERIES DUE IN 2030		35,000,000		127,283			09/15/2020	09/15/2030	09/15/2020	09/15/2030	35,000,000	927,500
31	3.66% SERIES DUE IN 2050		35,000,000		127,283			09/15/2020	09/15/2050	09/15/2020	09/15/2050	35,000,000	1,281,000
32	[e] Footnote												
33	Subtotal		756,720,000		4,735,799		367,900					706,720,000	25,860,084
33	TOTAL		781,720,000									731,720,000	26,001,537

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: ClassAndSeriesOfObligationCouponRateDescription
The interest rate varies on this note. The interest rate is as of December 31, 2021.
(b) Concept: ClassAndSeriesOfObligationCouponRateDescription
Bonds purchased back on 11/1/2021 originally scheduled to mature on 8/1/2027
(c) Concept: ClassAndSeriesOfObligationCouponRateDescription
The interest rate varies on this pollution control bond. The interest rate is as of December 31, 2021.
(d) Concept: ClassAndSeriesOfObligationCouponRateDescription
The interest rate varies on this term loan bond. The interest rate is as of December 31, 2021.
(e) Concept: ClassAndSeriesOfObligationCouponRateDescription
On December 2, 2020 the Kentucky PSC approved Duke Energy Kentucky's long-term financing application authorizing the issuance of up to $250 million of secured and/or unsecured notes, and $76.72 million of tax-exempt private activity bonds to refund existing tax exempt bonds. Authorization expires 12/31/2022.

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ 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)	53,405,580
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Contributions in Aid of Construction	2,069,093
6	Total	2,069,093
9	Deductions Recorded on Books Not Deducted for Return	
10	Federal & State Income Tax Deducted for Books	10,059,978
11	Other Deductions Recorded on Books Not Deducted for Return	
12	T13A08: Book Depreciation/Amortization	72,480,885
13	T13B45: Asset Retirement Obligation - Coal Ash	14,857,543
14	T22H47: Coal Ash Capitalized for Tax	5,305,890
15	T20A38: Regulatory Asset - Deferred Plant Costs	3,913,226
16	T15B29: Reg Asset-Pension Post Retirement PAA-FAS87Qual and Oth	3,183,879
17	T13B08: ASSET RETIREMENT OBLIGATION	2,313,176
18	T13B31: Impairment of Plant Assets	2,271,499
19	T19A71: Reg Asset/Liab - ESM Deferral	2,216,533
20	T15B07: Cash Flow Hedge - Reg Asset/Liab	1,596,353
21	T13A26: Tax Interest Capitalized	1,584,789
22	T22H54: Coal Ash Spend Reg Asset Approved - Retail (NC & MW)	1,391,902
23	Other	5,391,216

24	Total	126,566,869
14	Income Recorded on Books Not Included in Return	
15	Allowance for Funds Used During Construction	(1,709,537)
16	Total	(1,709,537)
19	Deductions on Return Not Charged Against Book Income	
20	T13A28: Tax Depreciation/Amortization	73,200,000
21	T13B33: T & D Repairs - Annual Adj.	27,650,000
22	T15B02: Reg Asset/Liab Def Revenue	18,090,156
23	T13B26: Equipment Repairs - Annual Adj	16,820,000
24	T13A16: Cost of Removal	14,616,002
25	T22H46: ARO Regulatory Asset - Coal Ash	11,044,537
26	T13A30: Tax Gains/Losses	5,300,000
27	T19A94: UNBILLED REVENUE - FUEL	4,642,502
28	T15B81: Reg Asset_Liab - Outage Costs	3,954,899
29	T22H45: Asset Retirement Costs - Coal Ash	3,813,006
30	T22A23: Retirement Plan Expense - Overfunded	3,529,616
31	T22B16: Miscellaneous NC Taxable Income Adj - DTL	3,343,574
32	T22H11: Asset Retirement Costs - ARO	1,802,923
33	T17A30: Property Tax Reserves	1,610,361
34	T15A22: Mark to Market - LT	1,596,821
35	Other	5,565,766
36	State Tax Deduction - Deduction on Return Not Charged Against Book Inc	(1,845,360)
37	Total	194,734,803
27	Federal Tax Net Income	(14,402,798)
28	Show Computation of Tax:	
29	Tax at 21% for Electric, Water, Non-Utility and Gas	(3,024,588)
30	NOL's	(3,258,725)
31	True Up Entries	(670,739)
32	Other Benefits	(173)
33	Total Tax	(6,954,225)
34	Total Federal Income Tax Accrual	(6,954,225)

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (g) 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.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) 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 (l) through (o) how the taxes were distributed. Report in column (o) 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 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) 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.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED			
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1	Fed Insurance Tax	Federal Insurance Tax	Federal	2021	848,904		2,120,235	2,749,308	(3,489)	216,342		1,778,252			341,982
2	Fed Fuel Tax	Fuel Tax	Federal	2021											
3	**Subtotal Federal Tax**				848,904		2,120,235	2,749,308	(3,489)	216,342		1,778,252			341,982
4	Sales and Use	State Tax	KY	2021	225,892		(473,967)	(1,909,020)	(1,517,150)	143,795		(453,946)			(20,021)
5	**Subtotal State Tax**				225,892		(473,967)	(1,909,020)	(1,517,150)	143,795		(453,946)			(20,021)
6	Property Tax	Local Tax	KY	2021	12,855,322		18,823,607	16,664,709	(189,172)	14,825,048		14,497,979			4,325,628
7	**Subtotal Local Tax**				12,855,322		18,823,607	16,664,709	(189,172)	14,825,048		14,497,979			4,325,628
8	State Property Tax	Property Tax	KY	2021	2,604,132					2,604,132					
9	**Subtotal Property Tax**				2,604,132					2,604,132					
10	Fed Unemployment	Unemployment Tax	Federal	2021	67		8,753	8,182		638		6,279			2,474
11	State Unemployment	Unemployment Tax	KY	2021	102		18,898	18,421		579		13,543			5,355
12	**Subtotal Unemployment Tax**				169		27,651	26,603		1,217		19,822			7,829
13	Fed Income Tax	Income Tax	Federal	2021	2,435,641		(6,954,226)	2,238,812		(6,757,397)		(8,317,550)			1,363,325
14	State Income Tax	Income Tax	KY	2021	(185,363)		(2,229,383)	(604,118)		(1,810,628)		(2,533,237)			303,854

15	**Subtotal Income Tax**				2,250,278		(9,183,609)	1,634,694		(8,568,025)		(10,850,787)			1,667,179
16	State Franchise	Franchise Tax	KY	2021	1		1		(1)	1		1			
17	**Subtotal Franchise Tax**				1		1		(1)	1		1			
40	TOTAL				18,784,698		11,313,918	19,166,294	(1,709,812)	9,222,510		4,991,321			6,322,597

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%									
3	4%									
4	7%									
5	10%	351			411.4	(428)		(77)	30 years	
6	30%	3,235,578						3,235,578	25 years	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	3,235,929				(428)		3,235,501		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
11	Gas - 4	2,720			411.4	(1,839)		881	46 years	
12	Gas -10	379,386			411.4	(55,790)		323,596	45 years	
13	Total Gas	382,106				(57,630)		324,476		
47	OTHER TOTAL									
48	GRAND TOTAL	3,618,035				(58,058)		3,559,977		

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

OTHER DEFERRED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	MISO MTEP Accrual	12,651,918			(555,393)	12,096,525
2	Deferred Revenue -Outdoor Lighting	1,123,168	415	141,398	125,220	1,106,990
3	Amort period 10 years over life					
4	of contracts					
5	MGP Reserve	668,331				668,331
6	FTR MTM gains/losses	158,441				158,441
7	Gas Refunds	20,789	805	64,701	193,978	150,066
8	Amort period varies					
9	SCHM Exec Cash Bal Plan				66,131	66,131
47	TOTAL	14,622,647		206,099	(170,064)	14,246,484

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

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

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities										
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)										
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other										
16.2	Other										
17	TOTAL (Acct 281) (Total of 8, 15 and 16)										
18	Classification of TOTAL										
19	Federal Income Tax										
20	State Income Tax										

21	Local Income Tax										

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	ADJUSTMENTS Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)
1	Account 282										
2	Electric	215,094,549	28,842,627	13,987,031	95,447	1,918,797		374,146			227,752,649
3	Gas	70,062,048	9,245,103	5,802,202	20,836					684,048	74,209,833
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	285,156,597	38,087,730	19,789,233	116,283	1,918,797		374,146		684,048	301,962,482
6											
7											
8											
9	TOTAL Account 282 (Total of Lines 5 thru 8)	285,156,597	38,087,730	19,789,233	116,283	1,918,797		374,146		684,048	301,962,482
10	Classification of TOTAL										
11	Federal Income Tax	235,515,406	29,498,685	15,754,286	93,104	1,536,310		448,936		401,477	247,769,140
12	State Income Tax	49,641,191	8,589,045	4,034,947	23,179	382,487		(74,790)		282,571	54,193,342
13	Local Income Tax										

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

			CHANGES DURING YEAR				ADJUSTMENTS				
							Debits		Credits		
Line No.	Account (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)
1	Account 283										
2	Electric										
3	Electric	25,373,878	13,122,033	6,863,624				352,881			31,279,406
9	TOTAL Electric (Total of lines 3 thru 8)	25,373,878	13,122,033	6,863,624				352,881			31,279,406
10	Gas										
11	Gas	5,071,383	530,934	301,866						138,440	5,438,891
17	TOTAL Gas (Total of lines 11 thru 16)	5,071,383	530,934	301,866						138,440	5,438,891
18	TOTAL Other										
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	30,445,261	13,652,967	7,165,490				352,881		138,440	36,718,297
20	Classification of TOTAL										
21	Federal Income Tax	24,878,274	10,931,424	5,737,143				344,539		54,552	29,782,568
22	State Income Tax	5,566,987	2,721,543	1,428,347				8,342		83,888	6,935,729
23	Local Income Tax										

NOTES

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	INCOME TAXES	130,062,605	190, 411	6,180,409		123,882,196
2	PENSION COSTS	6,041,411	182.3, 228.3, 254, 926	229,339	356,897	6,168,969
3	DSM ENERGY EFFICIENCY- Order #2015-00368	1,003,631			(155,805)	847,826
4	DEFERRED FORCED OUTAGE- Order #2017-00321	1,887,187			(1,887,187)	
41	TOTAL	138,994,834		6,409,748	(1,686,095)	130,898,991

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

Electric Operating Revenues

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.
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 page 108, 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.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	158,444,225	136,674,631	1,497,185	1,488,203	130,738	130,434
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	139,152,281	122,611,845	1,533,224	1,417,396	14,235	13,899
5	Large (or Ind.) (See Instr. 4)	59,283,498	55,859,125	750,976	745,572	356	362
6	(444) Public Street and Highway Lighting	1,680,436	1,650,852	13,143	13,827	530	469
7	(445) Other Sales to Public Authorities	13,693,368	15,397,543	150,815	184,862	655	793
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales	53,505	45,621	666	591		
10	TOTAL Sales to Ultimate Consumers	372,307,313	332,239,617	3,946,009	3,850,451	146,514	145,957
11	(447) Sales for Resale	15,522,798	9,044,323	553,959	379,710	1	1
12	TOTAL Sales of Electricity	387,830,111	341,283,940	4,499,968	4,230,161	146,515	145,958
13	(Less) (449.1) Provision for Rate Refunds	(1,162,077)	1,181,644				
14	TOTAL Revenues Before Prov. for Refunds	388,992,188	340,102,296	4,499,968	4,230,161	146,515	145,958
15	Other Operating Revenues						
16	(450) Forfeited Discounts		12,922				

17	(451) Miscellaneous Service Revenues	[a]208,589	[d]161,780				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	1,521,736	1,329,087				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[b]2,970,600	[e]1,908,938				
22	(456.1) Revenues from Transmission of Electricity of Others	2,894,440	1,187,925				
23	(457.1) Regional Control Service Revenues	229,226	156,183				
24	(457.2) Miscellaneous Revenues	[c]2,203,029	[f]2,032,957				
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	10,027,620	6,789,792				
27	TOTAL Electric Operating Revenues	399,019,808	346,892,088				

Line12, column (b) includes $ 4,182,085 of unbilled revenues.
Line12, column (d) includes 23,334 MWH relating to unbilled revenues

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: MiscellaneousServiceRevenues

Non-Utility Miscellaneous Revenue	$	171,947
Power Delivery Revenue		48,293
Green Power		13,997
Jobbing and Contract Work		(25,648)
Total	$	208,589

(b) Concept: OtherElectricRevenue

RSG Revenue - MISO Make Whole	$	2,984,979
Other Electric Revenues		15,000
Profit Or Loss On Sale Of M&S		654
Data Processing Service		960
Sales & Use Tax Collection Fee		600
Gross Up-Contr In Aid Of Const		(31,593)
Total	$	2,970,600

(c) Concept: MiscellaneousRevenue

PJM Reactive Rev	$	2,203,029
Total	$	2,203,029

(d) Concept: MiscellaneousServiceRevenues

Non-Utility Miscellaneous Revenue	$	140,047
Power Delivery Revenue		11,847
Green Power		11,124
Jobbing and Contract Work		(1,238)
Total	$	161,780

(e) Concept: OtherElectricRevenue

RSG Revenue - MISO Make Whole	$	1,907,378
Data Processing Service		960
Sales & Use Tax Collection Fee		600
Total	$	1,908,938

(f) Concept: MiscellaneousRevenue

PJM Reactive Rev	$	2,032,957
Total	$	2,032,957

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Scheduling, System Control, and Dispatch	47,083	93,353	168,518	229,226
46	TOTAL	47,083	93,353	168,518	229,226

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential SHEET 30 (1)	1,516,485	157,190,939	130,738	11,599	0.1037
41	TOTAL Billed Residential Sales	1,516,485	157,190,939	130,738	11,599	0.1037
42	TOTAL Unbilled Rev. (See Instr. 6)	(19,300)	1,253,286			(0.0649)
43	TOTAL	1,497,185	158,444,225	130,738	11,599	0.1058

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	SHEET 40 (8)					
2	SHEET 42 (9)					
41	TOTAL Billed Small or Commercial					
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)					
43	TOTAL Small or Commercial	1,533,224	139,152,281	14,235		

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
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41	TOTAL Billed Large (or Ind.) Sales					
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)					
43	TOTAL Large (or Ind.)	750,976	59,283,498	356		

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	SHEET 40 (8)	983,470	94,899,260	12,508	78,627	0.0965
2	SHEET 42 (9)	11,853	922,200	78	151,962	0.0778
3	SHEET 43 (10)	67	7,883	4	16,750	0.1177
4	SHEET 44 (11)	6,067	609,455	133	45,617	0.1005
5	SHEET 60 (18)	114	50,378	38	3,000	0.4419
6	SHEET 69 (19)	206	35,446	28	7,357	0.1721
7	SHEET 61 (17)	2	114	2	1,000	0.0570
8	SHEET 62(15)	3,588	421,115	100	35,880	0.1174
9	SHEET 51 (14)	168,285	11,354,111	8	21,035,625	0.0675
10	SHEET 41 (13)	1,041,797	80,520,125	153	6,809,131	0.0773
11	SHEET 45 (12)	8,898	766,949	6	1,483,000	0.0862
12	SHEET 30 (7)	10,916	1,233,028	1,533	7,121	0.1130
13	SHEET 73(22)	52,950	5,081,291	0		0.0960
41	TOTAL Billed Commercial and Industrial Sales	2,288,213	195,901,355	14,591	29,675,069	0.0856
42	TOTAL Unbilled Rev. (See Instr. 6)	(4,013)	2,534,424			(0.6316)
43	TOTAL	2,292,226	193,366,931	14,591	29,675,069	0.0844

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Sheet 40 (24)	804	83,477	22	36,545	0.1038
2	Sheet 60 (25)	8,903	1,356,778	350	25,437	0.1524
3	Sheet 66 (26)	398	75,965	1	398,000	0.1909
4	Sheet 71					
5	Sheet 61 (29)	3,038	164,216	157	19,350	0.0541
41	TOTAL Billed Public Street and Highway Lighting	13,143	1,680,436	530	479,333	0.1279
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	13,143	1,680,436	530	479,333	0.1279

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	SHEET 30 (30)	2	368	1	2,000	0.1840
2	SHEET 40(31)	63,908	6,492,777	572	111,727	0.1016
3	SHEET 42(32)	5,099	418,347	14	364,214	0.0820
4	SHEET 43 (33)	144	18,726	8	18,000	0.1300
5	SHEET 44 (34)	183	20,008	45	4,067	0.1093
6	SHEET 45 (35)	5,471	465,476	3	1,823,667	0.0851
7	SHEET 41 (36)	48,379	3,859,064	8	6,047,375	0.0798
8	SHEET 51 (37)	25,644	1,809,611	2	12,822,000	0.0706
9	SHEET 65 (38)	578	79,044			0.1368
10	SHEET 73 (41)	1,261	126,442			0.1003
11	SHEET 61 (43)	166	9,131	2	83,000	0.0550
41	TOTAL Billed Other Sales to Public Authorities	150,835	13,298,994	655	21,276,050	0.0882
42	TOTAL Unbilled Rev. (See Instr. 6)	(20)	394,374			(19.7187)
43	TOTAL	150,815	13,693,368	655	21,276,050	0.0908

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Interdepartmental Sales	666	53,505			0.0803
41	TOTAL Billed Interdepartmental Sales	666	53,505			0.0803
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	666	53,505			0.0803

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
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41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		(1,162,077)			

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SALES OF ELECTRICITY BY RATE SCHEDULES

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4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
41	TOTAL Billed - All Accounts	3,969,342	368,125,229	146,514	51,442,051	0.0927
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	(23,333)	4,182,084			(0.1792)
43	TOTAL - All Accounts	3,946,009	372,307,313	146,514	51,442,051	0.0944

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ 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).
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.

   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 (g) through (k).
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW)		Megawatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	
1	PJM Settlement, Inc.	OS	MBRT1				553,941		15,525,791		15,525,791
2	PJM Settlement, Inc.	AD	MBRT1				18		(2,993)		(2,993)
15	Subtotal - RQ										
16	Subtotal-Non-RQ						553,959		15,522,798		15,522,798
17	Total						553,959		15,522,798		15,522,798

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	2,473,587	2,339,123
5	(501) Fuel	55,555,683	51,335,719
6	(502) Steam Expenses	15,449,544	14,930,305
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	733,945	923,676
10	(506) Miscellaneous Steam Power Expenses	1,422,135	1,874,178
11	(507) Rents		60
12	(509) Allowances	733	933
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	75,635,627	71,403,994
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,174,570	1,767,154
16	(511) Maintenance of Structures	6,094,616	6,567,849
17	(512) Maintenance of Boiler Plant	11,047,145	10,174,608
18	(513) Maintenance of Electric Plant	3,455,166	1,668,755
19	(514) Maintenance of Miscellaneous Steam Plant	3,378,280	2,306,991
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	26,149,777	22,485,357
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	101,785,404	93,889,351
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-Nuclear. Power (Enter Total of 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 (Total of Lines 50 & 58)		
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	302,851	363,801
63	(547) Fuel	4,448,773	2,860,342
64	(548) Generation Expenses	134,838	98,666
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	1,087,335	1,145,877
66	(550) Rents		
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	5,973,797	4,468,686
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	245,684	228,076
70	(552) Maintenance of Structures	320,854	232,569
71	(553) Maintenance of Generating and Electric Plant	919,762	1,123,437
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	333,146	428,925
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	1,819,446	2,013,007
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	7,793,243	6,481,693
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	96,616,963	46,714,218
76.1	(555.1) Power Purchased for Storage Operations	0	
77	(556) System Control and Load Dispatching	118	185
78	(557) Other Expenses	(13,298,638)	6,636,056
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	83,318,443	53,350,459
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	192,897,090	153,721,503

81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	4,185	4,242
85	(561.1) Load Dispatch-Reliability	74,182	88,397
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	361,043	411,016
87	(561.3) Load Dispatch-Transmission Service and Scheduling	46,470	55,048
88	(561.4) Scheduling, System Control and Dispatch Services	2,768,097	2,203,478
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	2,073,859	2,014,234
93	(562) Station Expenses	115,176	97,322
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	15,778	41,917
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	19,455,367	19,283,242
97	(566) Miscellaneous Transmission Expenses	126,660	182,451
98	(567) Rents		
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	25,040,817	24,381,347
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures	28,359	28,462
103	(569.1) Maintenance of Computer Hardware	42	56
104	(569.2) Maintenance of Computer Software	119,067	129,323
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	180,022	249,717
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	310,946	1,023,598
109			

	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of Lines 101 thru 110)	638,436	1,431,156
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	25,679,253	25,812,503
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	1,922,719	1,722,632
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	1,922,719	1,722,632
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 Operation Expenses (Enter Total of Lines 123 and 130)	1,922,719	1,722,632
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	55,870	54,356
135	(581) Load Dispatching	373,632	369,057
136	(582) Station Expenses	92,075	52,188
137	(583) Overhead Line Expenses	232,087	341,290
138	(584) Underground Line Expenses	352,338	263,049

138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	410,391	387,665
141	(587) Customer Installations Expenses	639,140	696,923
142	(588) Miscellaneous Expenses	1,298,812	1,646,815
143	(589) Rents	73,642	21,115
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	3,527,987	3,832,458
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	61,664	85,450
147	(591) Maintenance of Structures	2,955	
148	(592) Maintenance of Station Equipment	361,551	248,871
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	6,352,091	6,666,053
150	(594) Maintenance of Underground Lines	190,198	238,188
151	(595) Maintenance of Line Transformers	34,129	39,218
152	(596) Maintenance of Street Lighting and Signal Systems	201,665	251,312
153	(597) Maintenance of Meters	343,491	364,008
154	(598) Maintenance of Miscellaneous Distribution Plant		7,382
155	TOTAL Maintenance (Total of Lines 146 thru 154)	7,547,744	7,900,482
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	11,075,731	11,732,940
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	93,650	58,024
160	(902) Meter Reading Expenses	294,899	377,786
161	(903) Customer Records and Collection Expenses	4,510,262	3,861,468
162	(904) Uncollectible Accounts	224,295	27,913
163	(905) Miscellaneous Customer Accounts Expenses	115	267
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	5,123,221	4,325,458
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		

167	(907) Supervision		
168	(908) Customer Assistance Expenses	82	3
169	(909) Informational and Instructional Expenses	7,223	151
170	(910) Miscellaneous Customer Service and Informational Expenses	268,693	377,061
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	275,998	377,215
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	1,410,637	1,247,250
176	(913) Advertising Expenses	40,506	29,421
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	1,451,143	1,276,671
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	8,771,467	6,632,099
182	(921) Office Supplies and Expenses	3,236,471	3,145,898
183	(Less) (922) Administrative Expenses Transferred-Credit	3	
184	(923) Outside Services Employed	2,079,112	3,757,367
185	(924) Property Insurance	1,032,286	934,344
186	(925) Injuries and Damages	605,631	831,019
187	(926) Employee Pensions and Benefits	5,220,484	6,362,006
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	839,865	871,093
190	(929) (Less) Duplicate Charges-Cr.	514,500	994,476
191	(930.1) General Advertising Expenses	59,365	47,864
192	(930.2) Miscellaneous General Expenses	686,255	1,128,462
193	(931) Rents	860,887	927,384
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	22,877,320	23,643,060
195	Maintenance		
196	(935) Maintenance of General Plant	29,916	34,122

197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	22,907,236	23,677,182
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	261,332,391	222,646,104

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

PURCHASED POWER (Account 555)

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

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

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES: MegaWatt Hours Received (i)	POWER EXCHANGES: MegaWatt Hours Delivered (j)	COST/SETTLEMENT OF POWER: Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+l+m) of Settlement ($) (n)
1	L'Oreal USA	IU	[a] (1)									298		298
2	PJM Settlement, Inc.	OS	MBRT1				2,099,629					98,354,520		98,354,520

3	PJM Settlement, Inc.	AD	MBRT1				1,916						30,609	30,609
4	Wells Fargo Securities	OS	(b) NJ									(1,768,464)		(1,768,464)
15	TOTAL						2,101,545	0	0	0	0	96,586,354	30,609	96,616,963

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: RateScheduleTariffNumber
The number "1" notation designates FERC approved Tariff and/or Rate Schedule as on file with the Commission. The tariff is applicable to qualifying cogeneration and small power production facilities.
(b) Concept: RateScheduleTariffNumber
NJ = Non-Jurisdictional Agreement.

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY: Megawatt Hours Received (i)	TRANSFER OF ENERGY: Megawatt Hours Delivered (j)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS: Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1	PJM Financial Transmission Rights (FTRs)			OS							110,011		2,784,429	2,894,440
2	PJM Facilities Charges			OS										
35	TOTAL							0	0	0	110,011	0	2,784,429	2,894,440

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or “true-ups” for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
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36					
37					
38					
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41					
42					
43					
44					
45					
46					
47					
48					
49					
40	TOTAL				

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: MegaWatt Hours Received (c)	TRANSFER OF ENERGY: MegaWatt Hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Midcontinent ISO	LFP					[a]417,750	417,750
2	PJM Interconnection	LFP			19,037,617			19,037,617
	TOTAL		0	0	19,037,617	0	417,750	19,455,367

FOOTNOTE DATA

(a) Concept: OtherChargesTransmissionOfElectricityByOthers

Accretion of the MTEP obligation.

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	43,032
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	4,234
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Business and Service Company Support	623,931
7	Director's Fees and Expenses	44,707
8	Shareholder's Communications/System	103,492
9	Dues and Subscriptions to Various Organizations	48,340
10	Account Analysis Reconciliation Adjustments	(181,481)
46	TOTAL	686,255

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

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 B 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 of 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			2,759,812		2,759,812
2	Steam Production Plant	21,843,864				21,843,864
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	11,219,496				11,219,496
7	Transmission Plant	1,960,755				1,960,755
8	Distribution Plant	13,093,943				13,093,943
9	Regional Transmission and Market Operation					
10	General Plant	570,559		668,241		1,238,800
11	Common Plant-Electric	(47,864)		115,267		67,403
12	TOTAL	48,640,753		3,543,320		52,184,073

B. Basis for Amortization Charges

Limited term electric depreciable plant base is $20,487,956, which is the cost of capitalized software and general plant assets. This includes amortized assets which have been fully amortized but not yet retired. Intangible plant is amortized over 3, 5 and 10 years, General Plant is over 5, 15, 20, 25 and 90 years..

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	311 - East Bend	183,719	100 years	(17)	2	S0.5	74 years
13	312 - East Bend - Boiler	486,057	40 years	(17)	2	S0.5	18 years
14	312 - East Bend - SCR	54,178	40 years	(17)	2	S0.5	15 years
15	3120 - East Bend 2 - Catalyst	7,984	10 years		5	S2.5	3 years
16	314 - East Bend - Turbogen	108,754	40 years	(17)	2	S0.5	17 years
17	315 - East Bend	48,174	55 years	(17)	2	R2	17 years
18	316 - East Bend	24,084	45 years	(17)	3	S0	23 years
19	3410 - Woodsdale Struc & Impv	36,379	60 years	(4)	3	R4	15 years
20	3420 - Woodsdale Fuel Hold Prd	61,311	55 years	(4)	2	S2.5	47 years
21	3430 - Woodsdale Prime Movers	9,183	45 years	(4)	3	R2	45 years
22	3431 - Woodsdale CT Rotables	1,157	45 years	(4)	3	R2	41 years
23	3440 - Woodsdale Generators	211,248	45 years	(4)	3	R2	17 years
24	3446 - Crittenden Solar - Gen	4,143	30 years	(5)	5	S1.5	25 years
25	3446 - Walton 1 Solar	3,109	30 years	(5)	5	S1.5	24 years
26	3446 - Walton 2 Solar	2,561	30 years	(5)	5	S1.5	25 years
27	3450 - Woodsdale Acc Elec Equipment	19,873	40 years	(4)	4	R2	15 years
28	3456 - Crittenden Solar	638	45 years	(5)	4	R2.5	39 years
29	3456 - Walton 1 Solar	534	45 years	(5)	4	R2.5	39 years
30	3456 - Walton 2 Solar	445	45 years	(5)	4	R2.5	39 years
31	3460 - Woodsdale Misc Plant Equipment	5,142	35 years	(4)	4	S0	12 years
32	3501 - Trans Rights of Way	1,334	65 years		1	R4	30 years
33	3520 - Trans Structure & Improvments	5,986	65 years	(10)	2	R2.5	60 years
34	3530 - Trans Station Equipment	29,637	50 years	(15)	2	R2	47 years
35	3531 - Woodsdale	9,374	50 years		2	R2.5	27 years
36	3532 - Major Equipment	11,452	60 years	(10)	2	R2.5	49 years

37	3534 - Step-up Equipment	7,057	30 years		4	R2.5	15 years
38	3550 - Trans Poles & Fixtures	14,613	55 years	(30)	2	R1.5	55 years
39	3560 - Trans OH Conduct & Device	10,157	50 years	(30)	2	R1	37 years
40	3561 - Trans OH Conduct-ClearRW	1,838	60 years		2	R3	57 years
41	3601 - Distrib Rights of Way	4,498	70 years		1	R3	20 years
42	3610 - Dist Structures & Improvments	1,420	65 years	(10)	2	R2.5	55 years
43	3620 - Dist Station Equipment	75,292	48 years	(15)	2	R2.5	47 years
44	3622 - Major Equipment (Distri)	41,350	60 years	(10)	2	R2.5	46 years
45	3640 - Poles, Towers & Fixtures	73,928	52 years	(40)	2	R0.5	33 years
46	3650 - Distr OH Conduct &Device	142,850	50 years	(25)	2	R1.5	40 years
47	3651 - Distr OH Conduct-ClearRW	7,057	60 years		2	R2.5	56 years
48	3660 - Distrib UG Conduits	43,352	65 years	(20)	2	S2.5	54 years
49	3670 - Distr UG Conduct &Device	81,816	58 years	(20)	2	R2	47 years
50	3680 - Line Transformers	73,597	45 years	(10)	2	R0.5	29 years
51	3682 - Cust Transformer Install	274	50 years	(10)		R1.5	50 years
52	3691 - UG Services	2,734	60 years	(25)	2	R2	48 years
53	3692 - OH Services	19,350	53 years	(20)	1	R1	31 years
54	3700 - Meters	1,775	24 years	(1)	6	R1	14 years
55	3700 - Meters Instrum Transformer	814	24 years	(1)	10	R1	5 years
56	3702 - Meters - AMI	25,913	15 years		7	S2.5	11 years
57	3711 - Area Lighting Cust Prem	1	20 years		5	S0.5	19 years
58	3712 - Company-owned Outdoot Lt	837	20 years		5	S0.5	20 years

59	3731 - Street Lighting OH	2,507	32 years	(10)	1	L0.5	6 years
60	3732 - Streetlighting Boulevard	3,368	45 years	(10)	1	R1.5	11 years
61	3733 - Streetlight Cust Pri Out	1,592	30 years	(10)	3	L0	2 years
62	3734 - Light Choice OLE - Public	2,165	30 years	(10)	3	L0	30 years
63	3900 - Structures & Improvement	165	35 years	(5)	3	S1	22 years
64	3910 - Office Furniture and Equipment	370	20 years			SQ	19 years
65	3910 - Office Furniture andEquipment	4	20 years			SQ	4 years
66	3911 - Electronic Data Proc Equipment	2,748	5 years		20	SQ	2 years
67	3920 - Elec Transportation	1,059	12 years		9	S3	8 years
68	3921 - Trailers Group	272	18 years	5	4	R2.5	5 years
69	3940 - Tools, Shop & Garage Equipment	3,115	25 years		4	SQ	14 years
70	3970 - Elec Communication Equipment	[a]8,914	15 years		7	SQ	10 years

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: DepreciablePlantBase

Depreciable Plant Base represents balances as of December 31, 2021, and excludes plant related to non-utility, asset retirement obligations, plant held for future use, capital and operating leases, land and intangibles.

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in columns (f), (g), and (h), expenses incurred during the year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

						EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR		
						CURRENTLY CHARGED TO						
Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (d)	Deferred in Account 182.3 at Beginning of Year (e)	Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
1	Kentucky Public Service Commission											
2	Gas Related	193,649		193,649		Gas	928	193,649				
3	Electric Related	686,710		686,710		Electric	928	686,710				
4	[(a)] Request for Rate Increase - Electric Case No. 2017-00321		85,465	85,465	341,859	Electric	928	85,465			85,465	256,394
5	[(b)] Request for Rate Increase - Gas Case No. 2018-00261		51,031	51,031	165,852	Gas	928	51,031			51,031	114,821
6	[(c)] Request for Rate Increase - Electric Case No. 2019-00271		67,834	67,834	293,946	Electric	928	67,834			67,834	226,112
7	Request for Rate Increase - Gas Case No. 2021-0190								145,138			145,138
8	Items reclassed in 2021 - Gas		(53)	(53)		Gas	928	(53)				
9	Items reclassed in 2021 - Electric		(143)	(143)		Electric	928	(143)				
46	TOTAL	880,359	204,134	1,084,493	801,657			1,084,493	145,138		204,330	742,465

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: RegulatoryCommissionDescription

The expenses from the Request for Rate Increase in Case Numbers; 2017-00321, 2018-00261, and 2019-00271 are deferred in FERC account 186

(b) Concept: RegulatoryCommissionDescription

The expenses from the Request for Rate Increase in Case Numbers; 2017-00321, 2018-00261, and 2019-00271 are deferred in FERC account 186

(c) Concept: RegulatoryCommissionDescription

The expenses from the Request for Rate Increase in Case Numbers; 2017-00321, 2018-00261, and 2019-00271 are deferred in FERC account 186

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ 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 and 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 and 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:
   - Electric R, D and D Performed Internally:
     - Generation
       - hydroelectric
         - Recreation fish and wildlife
         - Other hydroelectric
       - Fossil-fuel steam
       - Internal combustion or gas turbine
       - Nuclear
       - Unconventional generation
       - Siting and heat rejection
     - Transmission
       - Overhead
       - Underground
     - Distribution
     - Regional Transmission and Market Operation
     - Environment (other than equipment)
     - Other (Classify and include items in excess of $50,000.)
     - Total Cost Incurred
   - Electric, R, D and D Performed Externally:
     - Research Support to the electrical Research Council or the Electric Power Research Institute
     - Research Support to Edison Electric Institute
     - Research Support to Nuclear Power Groups
     - Research Support to Others (Classify)
     - Total Cost Incurred
3. Include in column (c) all R, D and 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 and 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 and 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 and 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.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Account (e)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Amount (f)	Unamortized Accumulation (g)
1	A. Electric R, D&D Performed Internally:						
2	Distribution	Research & Development Administration Costs	4,234		930.70	4,234	
3	TOTAL ELECTRIC R, D&D PERFORMED INTERNALLY		4,234			4,234	
4	B. Electric R, D&D Performed Externally:						
5	Electric Power Research Institute	Electric Power Research Institute Membership		109,955	Various	109,955	
6		Other (Less than $50K each)					
7	TOTAL ELECTRIC R, D&D PERFORMED EXTERNALLY			109,955		109,955	

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ 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	8,128,517		
4	Transmission	516,190		
5	Regional Market			
6	Distribution	1,461,493		
7	Customer Accounts	1,936,951		
8	Customer Service and Informational	76,658		
9	Sales			
10	Administrative and General	8,670,365		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	20,790,174		
12	Maintenance			
13	Production	4,769,824		
14	Transmission	249,165		
15	Regional Market			
16	Distribution	1,530,093		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	6,549,082		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	12,898,341		
21	Transmission (Enter Total of lines 4 and 14)	765,355		
22	Regional Market (Enter Total of Lines 5 and 15)			

23	Distribution (Enter Total of lines 6 and 16)	2,991,586		
24	Customer Accounts (Transcribe from line 7)	1,936,951		
25	Customer Service and Informational (Transcribe from line 8)	76,658		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	8,670,365		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	27,339,256	745,233	28,084,489
29	Gas			
30	Operation			
31	Production - Manufactured Gas	170,283		
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply	364,583		
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution	2,806,251		
37	Customer Accounts	1,258,683		
38	Customer Service and Informational	134,234		
39	Sales			
40	Administrative and General	2,442,157		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	7,176,191		
42	Maintenance			
43	Production - Manufactured Gas	21,841		
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			
48	Distribution	761,048		
49	Administrative and General	5,858		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	788,747		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	192,124		

53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	364,583		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)	3,567,299		
58	Customer Accounts (Line 37)	1,258,683		
59	Customer Service and Informational (Line 38)	134,234		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	2,448,015		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	7,964,938	12,116	7,977,054
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	35,304,194	757,349	36,061,543
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	16,254,929	557,621	16,812,550
69	Gas Plant	7,286,358	305,080	7,591,438
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	23,541,287	862,701	24,403,988
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,206,492		2,206,492
74	Gas Plant	508,973		508,973
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,715,465		2,715,465
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Projects For Duke's Subsidiaries & Merchandising	31,667		31,667
80	Other Work in Progress	232,575		232,575
81	Other Accounts	1,239,974		1,239,974
82				

83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	1,504,216		1,504,216
96	TOTAL SALARIES AND WAGES	63,065,162	1,620,050	64,685,212

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

COMMON UTILITY PLANT AND EXPENSES

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

1. COMMON UTILITY PLANT

COMMON PLANT IN SERVICE

Account Title	Bal. Beg. of Yr	Additions (A)	Retirements	Transfers (B)	Balance YE
303 Misc. Intangible Plant	22,334,459	32,150	0	0	22,366,609
370 Common AMI Meters	—	—	—	—	—
389 Land and Land Rights	1,041,678	—	—	—	1,041,678
390 Struct & Improvements	12,613,071	187,524	1,003,777	—	13,804,372
391 Office Furniture & Equipment	792,351	(3,482)	(35,358)	—	753,511
Electronic Data Processing	40,535	—		—	40,535
392 Transportation Equipment	—	—	—	—	—
393 Stores Equipment	—	—	—	—	—
394 Tools, Shop & Garage Equip	116,843	—	(2,993)	—	113,850
395 Laboratory Equipment	—	—	—	—	—
397 Communication Equipment	8,110,797	—	(1,696,794)	—	6,414,003
398 Miscellaneous Equipment	96,709	(1,408)	—	—	95,301
399 ARO General Plant	226,897	—	—	—	226,897
Total Common Plt in Service	45,373,340	214,784	(731,368)	—	44,856,756
CWIP	2,004,636	74,378	—	—	2,079,014
Total Common Utility Plant in Ser.	47,377,976	289,162	(731,368)	—	46,935,770

ALLOCATION OF COMMON PLANT TO UTILITY DEPARTMENTS (C)

Summary by Account Estimated as of 12/31/2021

Gas Department	28.64%	13,442,405
Electric Department	71.36%	33,493,366
	100.00%	46,935,770

(A) Classification of Account 106, Completed Construction Not Classified, included in the Additions column.

(B) Represents reclassification between utility departments and primary plant accounts.

(C) The percentages used to allocate Common Plant to utility departments are the weighted averages resulting from the application of allocation factors to the investment based on Gross Plant as of 12/31/2021.

2. ACCUMULATED PROVISION FOR DEPRECIATION
AND AMORTIZATION OF COMMON UTILITY PLANT

AND AMORTIZATION OF COMMON UTILITY PLANT

Balance - Beginning of Year		30,396,627
Depreciation provision for the year charged to:		
(403) Depreciation Expense (1)	(65,682)	
(404) Amortization-Limited Term Plant	115,267	
(403.1) Depreciation Expense (1)	(7,650)	
		41,935
Net Charges for Plant Retired:		
Book Cost of Plant Retired	(731,368)	
Cost of Removal	(60,829)	
Salvage (Credit)	—	
		(792,197)
Other Items:		
Transfers & Adjustments	—	
		—
Balance - End of the Year		29,646,364

ALLOCATION OF ACCUMULATED PROVISION FOR DEPRECIATION TO UTILITY DEPARTMENTS (3)

Summary by Account Estimated as of 12/31/2021

Gas Department	28.64%	8,490,719
Electric Department	71.36%	21,155,645
	100.00%	29,646,364

METHOD OF DETERMINATION OF DEPRECIATION & AMORTIZATION

Common Plant in Service	Rate (4)
Miscellaneous Intangible Plant	Note (2)
Structures and Improvements	1.95%
Office Furniture and Equipment	5.00%
Electronic Data Processing Equipment	20.00%
Tools, Shop & Garage Equipment	4.00%
Transportation & Power Operated Equipment	Note (4)
Communication Equipment	6.67%
Miscellaneous Equipment	6.67%

(1) The Respondent determines its monthly provision for depreciation by the application of rates to the previous month's balance of property capitalized in each primary plant account plus total Account 106 - Completed Construction Not Classified.

(2) The Respondent amortized its investment in Miscellaneous Intangible Plant equally over 60 months for certain projects.

(3) The percentages used to allocate the Common Plant Accumulated Provision for Depreciation balances to utility departments are the weighted averages resulting from the application of allocation factors to the balance of Common Plant Accumulated Provision at 12/31/2021. These factors are based on Gross Plant as of 12/31/2021.

(4) In 1997, the Respondent adopted vintage year accounting for general plant accounts in accordance with FERC Accounting Release No. 15.

(5) The Respondent amortized its investment in Transportation & Power Operated Equipment over the estimated lives of the individual assets.

3. COMMON UTILITY PLANT EXPENSE ACCOUNTS

Common utility plant expense accounts are not maintained, but such expenses are allocated to gas and electric departments principally on one or more of the following bases:

Floor space utilized for buildings and office equipment
General labor - total company
Number of gas and electric customers
IT operations
Numbers of customers
Three factor formula

4. COMMISSION APPROVAL

Prior to establishment of original cost, Messrs. Brenner and Eilers of the respondent and Campbell and Schwartz from Columbia System met with Mr. Smith of the Federal Power Commission to discuss amongst other things, the Federal Power Commission's permission to use the Common Utility Plant accounts. It was pointed out by the representatives of the Respondent that because of the nature of the Respondent's operations it was impossible and impractical to assign certain types of equipment directly to either gas or electric utility plant. Because of the facts presented, Mr. Smith gave the Respondent's respresentatives verbal permission to use the common plant accounts.

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	7,439,050	17,383,193	44,249,424	97,956,807
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	2,999,246	8,609,699	13,647,005	15,178,718
4	Transmission Rights	1,126,076	1,912,044	2,494,659	2,732,544
5	Ancillary Services				
6	Other Items (list separately)				
7	Ancillary Services (Account 555)	166,499	290,857	327,949	428,322
8	Ancillary Services (Account 447)	58,461	144,529	301,247	344,081
46	TOTAL	11,789,332	28,340,322	61,020,284	116,640,472

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.
In columns for usage, report usage-related billing determinant and the unit of measure.

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch			776,587			[a]229,225
2	Reactive Supply and Voltage			1,674,165			1,881,230
3	Regulation and Frequency Response			781,280			
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other			610,610			[b]3,901,943
8	Total (Lines 1 thru 7)			3,842,642			6,012,398

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: AncillaryServicesSoldAmount

Revenues from PJM

(b) Concept: AncillaryServicesSoldAmount

Facilities Charge Revenues from PJM are included in total Other Revenues. ($51,886)

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ 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.

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)
	NAME OF SYSTEM: Duke Energy Kentucky									
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total									

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

Monthly ISO/RTO Transmission System Peak Load

1. Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
5. Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

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

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 2022-04-18	Year/Period of Report End of: 2021/ 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)	3,946,009
3	Steam	2,542,673	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	553,959
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	804
7	Other	57,789	27	Total Energy Losses	201,235
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	2,600,462	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	4,702,007
10	Purchases (other than for Energy Storage)	2,101,545			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	0			
13	Delivered	0			
14	Net Exchanges (Line 12 minus line 13)	0			
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, 10.1, 14, 18 and 19)	4,702,007			

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

MONTHLY PEAKS AND OUTPUT

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

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: Duke Energy Kentucky					
29	January	404,536	40,129	608	29	9
30	February	382,257	31,599	654	17	8
31	March	449,721	133,102	581	2	8
32	April	346,670	54,997	548	28	15
33	May	364,398	42,433	727	24	17
34	June	483,261	102,680	799	29	16
35	July	427,849	10,326	766	26	16
36	August	430,273	20,787	814	12	16
37	September	429,700	88,333	722	14	15
38	October	308,713	988	596	11	17
39	November	315,067	975	568	23	8
40	December	359,562	27,610	579	7	18
41	Total	4,702,007	553,959			

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

Steam Electric Generating Plant Statistics

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.
9. Items under Cost of Plant are based on USofA 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.

Line No.	Item (a)	Plant Name: 0	Plant Name: East Bend	Plant Name: Miami Fort 6	Plant Name: Woodsdale CT
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)		[(a)] Steam	[(b)] Steam	Combustion Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		Conventional	Conventional	Conventional
3	Year Originally Constructed		1981	1960	1992
4	Year Last Unit was Installed		1981	1960	1993
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)		[(c)] 768	[(d)] 168	[(e)] 572
6	Net Peak Demand on Plant - MW (60 minutes)		618		518
7	Plant Hours Connected to Load		5,288		572
8	Net Continuous Plant Capability (Megawatts)				
9	When Not Limited by Condenser Water		600		564
10	When Limited by Condenser Water		600		476
11	Average Number of Employees		87		19
12	Net Generation, Exclusive of Plant Use - kWh		2,542,673,000		57,789,000
13	Cost of Plant: Land and Land Rights		7,036,025		2,258,588
14	Structures and Improvements		183,717,638		36,379,260
15	Equipment Costs		734,808,562		307,911,036
16	Asset Retirement Costs		100,701,443		

17	Total cost (total 13 thru 20)		1,026,263,668		346,548,884
18	Cost per KW of Installed Capacity (line 17/5) Including		1,336.2808		605.8547
19	Production Expenses: Oper, Supv, & Engr		2,473,587		293,992
20	Fuel		[f]54,171,470		[g]4,420,219
21	Coolants and Water (Nuclear Plants Only)				
22	Steam Expenses		15,449,544		132,459
23	Steam From Other Sources				
24	Steam Transferred (Cr)				
25	Electric Expenses		733,945		1,051,735
26	Misc Steam (or Nuclear) Power Expenses		1,422,135		
27	Rents				
28	Allowances				
29	Maintenance Supervision and Engineering		2,174,570		232,744
30	Maintenance of Structures		6,094,058		295,190
31	Maintenance of Boiler (or reactor) Plant		11,047,145		
32	Maintenance of Electric Plant		3,389,984	65,183	919,762
33	Maintenance of Misc Steam (or Nuclear) Plant		3,378,281		333,147
34	Total Production Expenses	0	100,334,719	65,183	7,679,248
35	Expenses per Net kWh				

35	**Plant Name**	East Bend	East Bend	Woodsdale CT	Woodsdale CT
36	Fuel Kind	Coal	Oil	Gas	Oil
37	Fuel Unit	T	bbl	Mcf	bbl
38	Quantity (Units) of Fuel Burned	1,193,530	20,219	790,939	9,512
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11,685	139,050	1	136,944
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	44.500	94.731	4.502	93.350
41	Average Cost of Fuel per Unit Burned	43.988	82.636	4.502	90.330
42	Average Cost of Fuel Burned per Million BTU	1.882	14.150	4.380	15.704
43	Average Cost of Fuel Burned per kWh Net Gen	0.021	0.001	0.062	0.015
44	Average BTU per kWh Net Generation	10,970.000	10,970.000	15,017.000	15,017.000

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Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: PlantKind

Effective 12-30-14, East Bend is owned 100% by Duke Energy Kentucky, Inc. Prior to that, East Bend was commonly owned by Duke Energy Kentucky, Inc. and the Dayton Power and Light Company with undivided interest of 69% and 31% respectively. Fuel expenses were shared on the basis of energy usage and other expenses were shared on an ownership basis.

(b) Concept: PlantKind

Miami Fort U6 retired 2015.

(c) Concept: InstalledCapacityOfPlant

The name plate rating is the actual name plate capacity that is determined by the generator's manufacturer and indicates the maximum output a generator can produce.

(d) Concept: InstalledCapacityOfPlant

The name plate rating is the actual name plate capacity that is determined by the generator's manufacturer and indicates the maximum output a generator can produce. Miami Fort U6 retired 5/31/2015.

(e) Concept: InstalledCapacityOfPlant

The name plate rating is the actual name plate capacity that is determined by the generator's manufacturer and indicates the maximum output a generator can produce.

(f) Concept: FuelSteamPowerGeneration

Excludes coal handling, sale of fly ash, and other miscellaneous costs to fuel expense Account 501 = $1,384,213.

(g) Concept: FuelSteamPowerGeneration

Excludes natural gas handling cost of $28,554.

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

Hydroelectric Generating Plant Statistics

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

Line No.	Item (a)	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:
1	Kind of Plant (Run-of-River or Storage)					
2	Plant Construction type (Conventional or Outdoor)					
3	Year Originally Constructed					
4	Year Last Unit was Installed					
5	Total installed cap (Gen name plate Rating in MW)					
6	Net Peak Demand on Plant-Megawatts (60 minutes)					
7	Plant Hours Connect to Load					
8	**Net Plant Capability (in megawatts)**					
9	(a) Under Most Favorable Oper Conditions					
10	(b) Under the Most Adverse Oper Conditions					
11	Average Number of Employees					
12	Net Generation, Exclusive of Plant Use - kWh					
13	**Cost of Plant**					
14	Land and Land Rights					
15	Structures and Improvements					
16	Reservoirs, Dams, and Waterways					
17	Equipment Costs					
18	Roads, Railroads, and Bridges					
19	Asset Retirement Costs					
20	Total cost (total 13 thru 20)					

21	Cost per KW of Installed Capacity (line 20 / 5)					
22	**Production Expenses**					
23	Operation Supervision and Engineering					
24	Water for Power					
25	Hydraulic Expenses					
26	Electric Expenses					
27	Misc Hydraulic Power Generation Expenses					
28	Rents					
29	Maintenance Supervision and Engineering					
30	Maintenance of Structures					
31	Maintenance of Reservoirs, Dams, and Waterways					
32	Maintenance of Electric Plant					
33	Maintenance of Misc Hydraulic Plant					
34	Total Production Expenses (total 23 thru 33)					
35	Expenses per net kWh					

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

Pumped Storage Generating Plant Statistics

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on Line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

Line No.	Item (a)	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:
1	Type of Plant Construction (Conventional or Outdoor)				
2	Year Originally Constructed				
3	Year Last Unit was Installed				
4	Total installed cap (Gen name plate Rating in MW)				
5	Net Peak Demaind on Plant-Megawatts (60 minutes)				
6	Plant Hours Connect to Load While Generating				
7	Net Plant Capability (in megawatts)				
8	Average Number of Employees				
9	Generation, Exclusive of Plant Use - kWh				
10	Energy Used for Pumping				
11	Net Output for Load (line 9 - line 10) - Kwh				
12	**Cost of Plant**				
13	Land and Land Rights				
14	Structures and Improvements				
15	Reservoirs, Dams, and Waterways				
16	Water Wheels, Turbines, and Generators				
17	Accessory Electric Equipment				
18	Miscellaneous Powerplant Equipment				
19	Roads, Railroads, and Bridges				

20	Asset Retirement Costs				
21	Total cost (total 13 thru 20)				
22	Cost per KW of installed cap (line 21 / 4)				
23	**Production Expenses**				
24	Operation Supervision and Engineering				
25	Water for Power				
26	Pumped Storage Expenses				
27	Electric Expenses				
28	Misc Pumped Storage Power generation Expenses				
29	Rents				
30	Maintenance Supervision and Engineering				
31	Maintenance of Structures				
32	Maintenance of Reservoirs, Dams, and Waterways				
33	Maintenance of Electric Plant				
34	Maintenance of Misc Pumped Storage Plant				
35	Production Exp Before Pumping Exp (24 thru 34)				
36	Pumping Expenses				
37	Total Production Exp (total 35 and 36)				
38	Expenses per kWh (line 37 / 9)				
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))				

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
4. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel Production Expenses (i)	Production Expenses: Maintenance Production Expenses (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
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Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In columns (e), (f) and (g) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (d) should include MWHs delivered/provided to a generator's own load requirements or used for the provision of ancillary services.
5. In columns (h), (i), and (j) report MWHs lost during conversion, storage and discharge of energy.
6. In column (k) report the MWHs sold.
7. In column (l), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the income generating activity.
8. In column (m), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined. In columns (n) and (o), report fuel costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated power.
9. In columns (q), (r) and (s) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compressors, generators, switching and conversion equipment, lines and equipment whose primary purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed.

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	MWHs (d)	MWHs delivered to the grid to support Production (e)	MWHs delivered to the grid to support Transmission (f)	MWHs delivered to the grid to support Distribution (g)	MWHs Lost During Conversion, Storage and Discharge of Energy Production (h)	MWHs Lost During Conversion, Storage and Discharge of Energy Transmission (i)	MWHs Lost During Conversion, Storage and Discharge of Energy Distribution (j)	MWHs Sold (k)	Revenues from Energy Storage Operations (l)	Power Purchased for Storage Operations (555.1) (Dollars) (m)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (n)	Other Costs Associated with Self-Generated Power (Dollars) (o)	Project Costs included in (p)	Production (Dollars) (q)	Transmission (Dollars) (r)	Distribution (Dollars) (s)
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Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ 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. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
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. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. 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.
5. 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.
6. 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).
7. 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.
8. 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.
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

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	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			
	From (a)	To (b)	Operating (c)	Designated (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)	(i)	Land (j)	Construction Costs (k)	Total Costs (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
1	69KV TRANSMISSION POOL		69.00	69.00	POLE	102.12	4.11			1,105,938	26,467,287	27,573,225				
2	Aero	Oakbrook	138.00	138.00	Pole	1.07		1	954ACSR45X7	229,937	1,606,960	1,836,897				
3	O&M Expenses												15,778	310,946		326,724
36	TOTAL					103.19	4.11	1		1,335,875	28,074,247	29,410,122	15,778	310,946	0	326,724

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	LINE COST					Construction
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
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42																	
43																	
44	TOTAL		0.00		0	0	0										

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ 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).
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.

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
1	AERO BOONE CO	Transmission		138	13	0	90	4	0	0	0	0
2	ALEXANDRIA SOUTH-CAMPBELL CO	Distribution		69	13	0	11	1	0	0	0	0
3	ATLAS-KENTON CO	Distribution		69	13	0	11	1	0	0	0	0
4	AUGUSTINE-COVINGTON, KY	Distribution		138	13	0	67	3	0	0	0	0
5	BEAVER-BOONE CO.	Distribution		69	13	0	21	2	0	0	0	0
6	BELLEVUE-CAMPBELL CO.	Distribution		138	13	0	45	2	0	0	0	0
7	BLACKWELL-GRANT CO.	Transmission		138	69	0	150	1	0	0	0	0
8	BUFFINGTON-KENTON CO.	Transmission		345	138	13	1178	7	1	0	0	0
9	CLARYVILLE-CAMBELL CO.	Distribution		69	13	0	32	3	0	0	0	0
10	COLD SPRING-KENTON CO.	Distribution		138	13	0	33	2	0	0	0	0
11	CONSTANCE-KENTON CO.	Distribution		138	13	0	45	2	0	0	0	0
12	COVINGTON - KENTON CO.	Distribution		69	13	0	45	2	0	0	0	0
13	CRESCENT-KENTON CO.	Distribution		138	13	0	67	3	0	0	0	0
14	CRITTENDEN-GRANT CO.	Distribution		69	13	0	21	2	0	0	0	0
15	[a] DAYTON - CAMPBELL CO.	Distribution		138	13	0	22	1	0	0	0	0
16	DECOURSEY-KENTON CO.	Distribution		69	13	0	11	1	0	0	0	0

17	DIXIE FLORENCE CO.	Distribution		69	13	0	67	3	0	0	0	0
18	DONALDSON ERLANGER CO.	Transmission		138	13	0	90	4	0	0	0	0
19	DRY RIDGE-GRANT CO.	Distribution		69	13	0	21	2	0	0	0	0
20	EMPIRE - BOONE CO.	Distribution		69	13	0	25	2	0	0	0	0
21	FLORENCE-BOONE CO.	Distribution		138	13	0	67	3	0	0	0	0
22	GRANT-GRANT CO.	Distribution		69	13	0	21	2	0	0	0	0
23	HANDS-KENTON CO.	Distribution		138	13	0	45	2	0	0	0	0
24	HEBRON- BOONE CO.	Distribution		138	13	0	45	2	0	0	0	0
25	KENTON FORT WRIGHT CO.	Transmission		138	66	0	167	3	0	0	0	0
26	KY. UNIVERSITY-CAMP. CO.	Distribution		138	13	0	45	2	0	0	0	0
27	LIMABURG FLORENCE CO.	Distribution		69	13	0	31	3	0	0	0	0
28	LONGBRANCH- BOONE CO.	Distribution		138	13	0	45	2	0	0	0	0
29	MARSHALL-CAMPBELL CO.	Distribution		69	13	0	11	1	0	0	0	0
30	MT ZION FLORENCE CO.	Distribution		138	13	0	45	2	0	0	0	0
31	OAKBROOK - BOONE CO	Distribution		138	69	0	172	2	0	0	0	0
32	RICHWOOD - BOONE CO.	Distribution		69	13	0	32	3	0	0	0	0
33	SILVER GROVE - CAMPBELL CO.	Transmission		138	13	0	22	1	0	0	0	0
34	THOMAS MORE - KENTON CO.	Distribution		69	13	0	22	1	0	0	0	0
35	VERONA - KENTON CO.	Distribution		69	13	0	21	2	0	0	0	0
36	VILLA-CRESTVIEW HLS., KY	Distribution		69	13	0	45	2	0	0	0	0
37	WHITE TOWER-KENTON CO.	Distribution		69	13	0	21	2	0	0	0	0
38	WILDER-WILDER, KY.	Transmission		138	69	13	502	4	0	0	0	0
39	YORK-NEWPORT, KY.	Distribution		138	13	0	22	1	0	0	0	0
40	TOTAL Transmission Substations						2199	24	1	—		
41	TOTAL Distribution Substations						1234	64		—		
42	TOTAL Generation Substations									—		
43	TOTAL						3433	88	1	0	0	0

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: SubstationNameAndLocation
The voltages reported in column (c), (d) and (e) are the highest in the substation. BUT not necessarily on the same transformer.

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ 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 Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	[a] Services Provided by Duke Energy Business Services	Duke Energy Business Services, LLC	Various	163,672,601
3	Customer and Market Services	Duke Energy Carolinas, LLC	Various	4,985,638
4	Generation Services	Duke Energy Carolinas, LLC	Various	940,263
5	Other Goods and Services	Duke Energy Carolinas, LLC	Various	1,550,844
6	Transmission and Distribution Services	Duke Energy Carolinas, LLC	Various	1,436,540
7	Customer and Market Services	Duke Energy Progress, LLC	Various	173,659
8	Generation Services	Duke Energy Progress, LLC	Various	811,070
9	Other Goods and Services	Duke Energy Progress, LLC	Various	219,202
10	Transmission and Distribution Services	Duke Energy Progress, LLC	Various	108,561
11	Customer & Market services	Duke Energy Florida, LLC	Various	88,670
12	Generation services	Duke Energy Florida, LLC	Various	70,279
13	Other goods and services	Duke Energy Florida, LLC	Various	162,652
14	Transmission and Distribution services	Duke Energy Florida, LLC	Various	19,356
15	Customer and Market Services	Duke Energy Indiana, LLC	Various	191,608
16	Generation Services	Duke Energy Indiana, LLC	Various	6,066,143
17	Other Goods and Services	Duke Energy Indiana, LLC	Various	1,829,057
18	Transmission and Distribution Services	Duke Energy Indiana, LLC	Various	83,049
19	Customer and Market Services	Duke Energy Ohio, Inc.	Various	2,788,635
20	Gas Distribution Services	Duke Energy Ohio, Inc.	Various	3,370,134
21	Other Goods and Services	Duke Energy Ohio, Inc.	Various	

22	Transmission and Distribution Services	Duke Energy Ohio, Inc.	Various	5,603,957
23	Gas Distribution Services	Piedmont Natural Gas Company, Inc.	Various	3,941,534
24	Other Goods and Services	Duke Energy Commercial Enterprises	Various	18,985
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Customer and Market Services	Duke Energy Carolinas, LLC	Various	67
22	Gas Distribution Services	Duke Energy Carolinas, LLC	Various	
23	Generation Services	Duke Energy Carolinas, LLC	Various	9,374
24	Other Goods and Services	Duke Energy Carolinas, LLC	Various	
25	Transmission and Distribution Services	Duke Energy Carolinas, LLC	Various	102,355
26	Customer and Market Services	Duke Energy Progress, LLC	Various	28
27	Gas Distribution Services	Duke Energy Progress, LLC	Various	
28	Generation Services	Duke Energy Progress, LLC	Various	3,785
29	Transmission and Distribution Services	Duke Energy Progress, LLC	Various	2,012
30	Customer and Market Services	Duke Energy Florida, LLC	Various	33
31	Generation Services	Duke Energy Florida, LLC	Various	1,133
32	Other Goods and Services	Duke Energy Florida, LLC	Various	1,260
33	Transmission and Distribution Services	Duke Energy Florida, LLC	Various	5,289
34	Transmission and Distribution Services	Duke Energy Business Services LLC	Various	1,439
35	Customer and Market Services	Duke Energy Indiana, LLC	Various	15
36	Gas Distribution Services	Duke Energy Indiana, LLC	Various	
37	Generation Services	Duke Energy Indiana, LLC	Various	1,055,348
38	Transmission and Distribution Services	Duke Energy Indiana, LLC	Various	240,273
39	Customer and Market Services	Duke Energy Ohio, Inc.	Various	73,056
40	Gas Distribution Services	Duke Energy Ohio, Inc.	Various	978,399
41	Other Goods and Services	Duke Energy Ohio, Inc.	Various	179,000
42	Transmission and Distribution Services	Duke Energy Ohio, Inc.	Various	1,301,182
43	Generation services	Duke Energy Ohio, Inc.	Various	
44	Gas Distribution Services	KO Transmission Company	Various	(9,345)
45	Customer and Market Services	Piedmont Natural Gas Company, Inc.	Various	49
46	Gas Distribution Services	Piedmont Natural Gas Company, Inc.	Various	2,433

42				

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfNonPowerGoodOrService

When an employee of the Service Company performs services for a Client Company, costs will be directly assigned or distributed or allocated. For allocated services, the allocation method will be on a basis reasonably related to the service performed. The Service Company Utility Service Agreement prescribes 23 Service Company functions and approximately 20 allocation methods.

Functions and Allocation Methods:

Information Systems

Number of Central Processing Unit Seconds Ratio/Millions of Instructions per Second

Number of Personal Computer Workstations Ratio

Number of Information Systems Servers Ratio

Number of Employees Ratio
Meters
Number of Customers Ratio
Transportation
Number of Employees Ratio
Three Factor Formula
Electric System Maintenance
Circuit Miles of Electric Transmission Lines Ratio
Circuit Miles of Electric Distribution Lines Ratio
Marketing and Customer Relations and Grid Solutions
Number of Customers Ratio
Electric Transmission & Distribution Engineering & Construction
Electric Transmission Plant's Construction - Expenditures Ratio
Electric Distribution Plant's Construction - Expenditures Ratio
Power Engineering & Construction
Electric Production Plant's Construction - Expenditures Ratio
Human Resources
Number of Employees Ratio
Supply Chain
Procurement Spending Ratio
Inventory Ratio
Facilities
Square Footage Ratio
Accounting
Three Factor Formula
Generating Unit MW Capability Ratio
Power Planning and Operations
Electric Peak Load Ratio
Weighted Avg of the Circuit Miles of Electric Distribution Lines Ratio and the Electric Peak Load Ratio
Sales Ratio
Weighted Avg of the Circuit Miles of Electric Transmission Lines Ratio and the Electric Peak Load Ratio
Generating Unit MW Capability Ratio
Public Affairs
Three Factor Formula
Weighted Avg of Number of Customers Ratio and Number of Employees Ratio
Legal
Three Factor Formula
Rates
Sales Ratio
Finance
Three Factor Formula
Rights of Way
Circuit Miles of Electric Transmission Lines Ratio
Circuit Miles of Electric Distribution Lines Ratio
Electric Peak Load Ratio
Internal Auditing

Three Factor Formula
Environmental, Health and Safety
Three Factor Formula
Sales Ratio
Fuels
Sales Ratio
Investor Relations
Three Factor Formula
Planning
Three Factor Formula
Executive
Three Factor Formula

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

FERC FINANCIAL REPORT
FERC FORM No. 2: Annual Report of Major Natural Gas Companies and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Natural Gas Act, Sections 10(a), and 16 and 18 CFR Parts 260.1 and 260.300. Failure to report may result in criminal fines, civil penalties, and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year/Period of Report:
Duke Energy Kentucky, Inc	End of: 2021/ Q4

FERC FORM NO. 2 (02-04)

INSTRUCTIONS FOR FILING FERC FORMS 2, 2-A and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Forms 2, 2-A, and 3-Q are designed to collect financial and operational information from natural gas companies subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be a non-confidential public use forms.

II. Who Must Submit

Each natural gas company whose combined gas transported or stored for a fee exceed 50 million dekatherms in each of the previous three years must submit FERC Form 2 and 3-Q.

Each natural gas company not meeting the filing threshold for FERC Form 2, but having total gas sales or volume transactions exceeding 200,000 dekatherms in each of the previous three calendar years must submit FERC Form 2-A and 3-Q.

Newly established entities must use projected data to determine whether they must file the FERC Form 3-Q and FERC Form 2 or 2-A.

III. What and Where to Submit

a. Submit FERC Form Nos. 2, 2-A and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 2, 2-A and 3-Q taxonomies..

b. The Corporate Officer Certification must be submitted electronically as part of the FERC Form 2 and 3-Q filings.

c. Submit immediately upon publication, by either eFiling or mailing two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders and any annual financial or statistical report regularly prepared and distributed to bondholders, security analysts, or industry associations. Do not include monthly and quarterly reports. Indicate by checking the appropriate box on Form 2, Page 3, List of Schedules, if the reports to stockholders will be submitted or if no annual report to stockholders is prepared. Unless eFiling the Annual Report to Stockholders, mail these reports to the Secretary of the Commission at:

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

d. For the Annual CPA certification, submit with the original submission of this form, a letter or report (not applicable to respondents classified as Class C or Class D prior to January 1, 1984) prepared in conformity with the current standards of reporting which will:

   i. Contain a paragraph attesting to the conformity, in all material respects, of the schedules listed below with the Commission's applicable Uniform Systems of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

   ii. be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 158.10-158.12 for specific qualifications.)

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

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

e. Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online .

f. Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 2 and 2-A free of charge from: https://www.ferc.gov/industries-data/natural-gas/industry-forms . Copies may also be obtained from the Public Reference and Files Maintenance Branch, Federal Energy Regulatory Commission, 888 First Street, NE. Room 2A, Washington, DC 20426 or by calling (202).502-8371

IV. When to Submit:

FERC Forms 2, 2-A, and 3-Q must be filed by the dates:

a. FERC Form 2 and 2-A --- by April 18th of the following year (18 C.F.R. §§ 260.1 and 260.2)

c. FERC Form 3-Q --- Natural gas companies that file a FERC Form 2-A must file the FERC Form 3-Q within 70 days after the reporting quarter (18 C.F.R. § 260.300).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the Form 2 collection of information is estimated to average 1,671.66 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the Form 2A collection of information is estimated to average 295.66 hours per response. The public reporting burden for the Form 3-Q collection of information is estimated to average 167 hours per response.

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

GENERAL INSTRUCTIONS

I. Prepare all reports in conformity with the Uniform System of Accounts (USofA) (18 C.F.R. Part 201). Interpret all accounting words and phrases in accordance with the USofA.

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

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

IV. For any page(s) that is not applicable to the respondent, indicate whether a schedule has been omitted by entering "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, page 2.

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

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

VII. For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

VIII. Footnote and further explain accounts or pages as necessary.

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

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

XI. Report all gas volumes in Dth unless the schedule specifically requires the reporting in another unit of measurement.

XII. Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

DEFINITIONS

I. Btu per cubic foot – The total heating value, expressed in Btu, produced by the combustion, at constant pressure, of the amount of the gas which would occupy a volume of 1 cubic foot at a temperature of 60°F if saturated with water vapor and under a pressure equivalent to that of 30°F, and under standard gravitational force (980.665 cm. per sec) with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of gas and air when the water formed by combustion is condensed to the liquid state (called gross heating value or total heating value).

II. Commission Authorization -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

III. Dekatherm – A unit of heating value equivalent to 10 therms or 1,000,000 Btu.

IV. Respondent – The person, corporation, licensee, agency, authority, or other legal entity or instrumentality on whose behalf the report is made.

EXCERPTS FROM THE LAW

Natural Gas Act, 15 U.S.C. 717-717w

"Sec. 10(a). Every natural-gas company shall file with the Commission such annual and other periodic or special reports as the Commission may by rules and regulations or order prescribe as necessary or appropriate to assist the Commission in the proper administration of this act. The Commission

b. FERC Form 3-Q --- Natural gas companies that file a FERC Form 2 must file the FERC Form 3-Q within 60 days after the reporting quarter (18 C.F.R.§ 260.300), and

reserves, cost of facilities, costs of maintenance and operation of facilities for the production, transportation, delivery, use, or sale of natural gas, costs of renewal and replacement of such facilities, transportation, delivery, use and sale of natural gas..."

"Section 16. The Commission shall have power to perform all and any acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this act. Among other things, such rules and regulations may define

may prescribe the manner and form in which such reports shall be made and require from such natural-gas companies specific answers to all questions upon which the Commission may need information. The Commission may require that such reports include, among other things, full information as to assets and liabilities, capitalization, investment and reduction thereof, gross receipts, interest dues and paid, depreciation, amortization, and other

accounting, technical, and trade terms used in this act; and may prescribe the form or forms of all statements declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and time within they shall be filed..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. See NGA § 22(a), 15 U.S.C. §717t-1(a).

FERC FORM NO. 2
REPORT OF MAJOR NATURAL GAS COMPANIES

IDENTIFICATION

01 Exact Legal Name of Respondent Duke Energy Kentucky, Inc		02 Year/ Period of Report End of: 2021/ Q4
03 Previous Name and Date of Change (if name changed during year) /		
04 Address of Principal Office at End of Year (Street, City, State, Zip Code) 1262 Cox Road, Erlanger, KY 410018		
05 Name of Contact Person Nicole Aquilina		06 Title of Contact Person Accounting Manager II
07 Address of Contact Person (Street, City, State, Zip Code) 4720 Piedmont Row Drive, Charlotte, NC 28210		
08 Telephone of Contact Person, Including Area Code 704-450-1230	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 04/18/2022

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.

11 Name Cynthia S. Lee	12 Title VP, CAO, and Controller
13 Signature Cynthia S. Lee	14 Date Signed 04/18/2022

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: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

List of Schedules (Natural Gas Company)

Enter in column (d) the terms "none," "not applicable," or "NA" as appropriate, to indicate no information or amounts have been reported for certain pages.

22	Investments	222	12-96	
23	Investments In Subsidiary Companies	224	12-96	N/A
24	Prepayments	230a	12-96	
25	Extraordinary Property Losses	230b	12-96	N/A
26	Unrecovered Plant And Regulatory Study Costs	230c	12-96	N/A
27	Other Regulatory Assets	232	REV 12-07	
28	Miscellaneous Deferred Debits	233	12-96	
29	Accumulated Deferred Income Taxes	234	REV 12-07	
	BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits)			
30	Capital Stock	250	12-96	
31	Capital Stock Subscribed, Capital Stock Liability for Conversion, Premium on Capital Stock, and Installments Recieved on Capital Stock	252	12-96	
32	Other Paid-In Capital	253	12-96	
33	Discount on Capital Stock	254	12-96	N/A
34	Capital Stock Expense	254	12-96	N/A
35	Securities Issued Or Assumed And Securities Refunded Or Retired During The Year	255.1	12-96	N/A
36	Long-Term Debt	256	12-96	
37	Unamortized Debt Expense, Premium And Discount On Long-Term Debt	258	12-96	
38	Unamortized Loss And Gain On Reacquired Debt	260	12-96	
39	Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes	261	12-96	
40	Taxes Accrued, Prepaid And Charged During Year, Distribution Of Taxes Charged	262	REV 12-07	
41	Miscellaneous Current And Accrued Liabilities	268	12-96	
42	Other Deferred Credits	269	12-96	
43	Accumulated Deferred Income Taxes-Other Property (Account 282)	274	REV 12-07	
44	Accumulated Deferred Income Taxes-Other (Account 283)	276	REV 12-07	
45	Other Regulatory Liabilities	278	REV 12-07	
	INCOME ACCOUNT SUPPORTING SCHEDULES			
46	Monthly Quantity & Revenue Data	299	NEW 12-08	
47	Gas Operating Revenues	300	REV 12-07	
48	Revenues From Transportation Of Gas Of Others Through Gathering Facilities	302	12-96	N/A
49	Revenues From Transportation Of Gas Of Others Through Transmission Facilities	304	12-96	
50	Revenues From Storing Gas Of Others	306	12-96	N/A
51	Other Gas Revenues	308	12-96	

52	Discounted Rate Services And Negotiated Rate Services	313	NEW 12-07	N/A
53	Gas Operation And Maintenance Expenses	317	12-96	
54	Exchange And Imbalance Transactions	328	12-96	N/A
55	Gas Used In Utility Operations	331	12-96	N/A
56	Transmission And Compression Of Gas By Others	332	12-96	N/A
57	Other Gas Supply Expenses	334	12-96	N/A
58	Miscellaneous General Expenses-Gas	335	12-96	
59	Depreciation, Depletion, and Amortization of Gas Plant		12-96	
59	Section A. Summary of Depreciation, Depletion, and Amortization Charges	336	12-96	
59	Section B. Factors Used in Estimating Depreciation Charges	338	12-96	
60	Particulars Concerning Certain Income Deductions And Interest Charges Accounts	340	12-96	
	COMMON SECTION		12-96	
61	Regulatory Commission Expenses	350	12-96	
62	Employee Pensions And Benefits (Account 926)	352	NEW 12-07	
63	Distribution Of Salaries And Wages	354	REVISED	
64	Charges For Outside Professional And Other Consultative Services	357	REVISED	
65	Transactions With Associated (Affiliated) Companies	358	NEW 12-07	
	GAS PLANT STATISTICAL DATA			
66	Compressor Stations	508	REV 12-07	N/A
67	Gas Storage Projects	512	12-96	N/A
67	Gas Storage Projects	513	12-96	
68	Transmission Lines	514	12-96	N/A
69	Transmission System Peak Deliveries	518	12-96	N/A
70	Auxiliary Peaking Facilities	519	12-96	
71	Gas Account - Natural Gas	520	REV 01-11	
72	Shipper Supplied Gas for the Current Quarter	521	REVISED 02-11	N/A
73	System Maps	522.1	REV. 12-96	N/A
74	Footnote Reference			
75	Footnote Text			
76	Stockholder's Reports (check appropriate box)			
	☐ Four copies will be submitted ☐ No annual report to stockholders is prepared			

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ 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.

Cynthia S. Lee

Vice President, Chief Accounting Officer and Controller

526 S Church St. Charlotte, NC 28202

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.

State of Incorporation: KY

Date of Incorporation: 03/20/1901

Incorporated Under Special Law:

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.

N/A
(a) Name of Receiver or Trustee Holding Property of the Respondent:

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

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

Kentucky - Gas and Electric

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

(1) ☐ Yes

(2) ☑ No

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Control Over Respondent

1. Report in column (a) the names of all corporations, partnerships, business trusts, and similar organizations that directly, indirectly, or jointly held control (see page 103 for definition of control) over the respondent at the end of the year. If control is in a holding company organization, report in a footnote the chain of organization.
2. If control is held by trustees, state in a footnote the names of trustees, the names of beneficiaries for whom the trust is maintained, and the purpose of the trust.
3. In column (b) designate type of control over the respondent. Report an "M" if the company is the main parent or controlling company having ultimate control over the respondent. Otherwise, report a "D" for direct, an "I" for indirect, or a "J" for joint control.

Line No.	Company Name (a)	Type of Control (b)	State of Incorporation (c)	Percent Voting Stock Owned (d)
1	Duke Energy Ohio	M	OH	100%

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Corporations Controlled by Respondent

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

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

Line No.	Name of Company Controlled (a)	Type of Control (b)	Kind of Business (c)	Percent Voting Stock Owned (d)	Footnote Reference (e)
1	N/A				Not Used

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Security Holders and Voting Powers

1. Give the names and addresses of the 10 security holders of the respondent who, at the date of the latest closing of the stock book or compilation of list of stockholders of the respondent, prior to the end of the year, had the highest voting powers in the respondent, and state the number of votes that each could cast on that date if a meeting were held. If any such holder held in trust, give in a footnote the known particulars of the trust (whether voting trust, etc.), duration of trust, and principal holders of beneficiary interests in the trust. If the company did not close the stock book or did not compile a list of stockholders within one year prior to the end of the year, or if since it compiled the previous list of stockholders, some other class of security has become vested with voting rights, then show such 10 security holders as of the close of the year. Arrange the names of the security holders in the order of voting power, commencing with the highest. Show in column (a) the titles of officers and directors included in such list of 10 security holders.
2. If any security other than stock carries voting rights, explain in a supplemental statement how such security became vested with voting rights and give other important details concerning the voting rights of such security. State whether voting rights are actual or contingent; if contingent, describe the contingency.
3. If any class or issue of security has any special privileges in the election of directors, trustees or managers, or in the determination of corporate action by any method, explain briefly in a footnote.
4. Furnish details concerning any options, warrants, or rights outstanding at the end of the year for others to purchase securities of the respondent or any securities or other assets owned by the respondent, including prices, expiration dates, and other material information relating to exercise of the options, warrants, or rights. Specify the amount of such securities or assets any officer, director, associated company, or any of the 10 largest security holders is entitled to purchase. This instruction is inapplicable to convertible securities or to any securities substantially all of which are outstanding in the hands of the general public where the options, warrants, or rights.

1. Give date of the latest closing of the stock book prior to end of year, and, in a footnote, state the purpose of such closing:	2. State the total number of votes cast at the latest general meeting prior to the end of year for election of directors of the respondent and number of such votes cast by proxy. Total: 585,333 By Proxy:	3. Give the date and place of such meeting:

Line No.	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES 4. Number of votes as of (date): Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
5	TOTAL votes of all voting securities	585,333	585,333		
6	TOTAL number of security holders	1	1		
7	TOTAL votes of security holders listed below	585,333	585,333		
8					
9					
10					
11					
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18					
19					
20					

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Important Changes During the Year

Give details concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Answer each inquiry. Enter "none" or "not applicable" where applicable. If the answer is given elsewhere in the report, refer to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration and state from whom the franchise rights were acquired. If the franchise rights were 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: Briefly describe the property, and the related transactions, and cite Commission authorization, if any was required. Give date journal entries called for by 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 conditions. 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 cite 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 or assumed by respondent as guarantor for the performance by another of any agreement or obligation, including ordinary commercial paper maturing on demand or not later than one year after date of issue: State on behalf of whom the obligation was assumed and amount of the obligation. Cite Commission authorization if any was required.
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, 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. Estimated increase or decrease in annual revenues caused by important rate changes: State effective date and approximate amount of increase or decrease for each revenue classification. State the number of customers affected.
12. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
13. 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.

1. None

2. See Notes to Financial Statements, Note 1, "Summary of Significant Accounting Policies"

3. See Notes to Financial Statements, Note 2, "Regulatory Matters"

4. None

5. None

6. See Notes to Financial Statements, Note 5, "Debt and Credit Facilities"

7. None

8. During the fourth quarter 2021, there were no large scale wage changes for Duke Energy Kentucky payroll company.
During the third quarter 2021, there were no large scale wage changes for Duke Energy Kentucky payroll company.
During the second quarter 2021, there were no large scale wage changes for Duke Energy Kentucky payroll company.
During the first quarter 2021, exempt and non-exempt employees in Duke Energy Kentucky payroll companies received merit increases of $3,327.

9. See Notes to Financial Statements, Note 2, "Regulatory Matters" and Note 3, "Commitments and Contingencies"

10. None

11. In Case No. 2021-00190, the Kentucky Public Service Commission approved an increase in annual gas base revenues effective January 4, 2022 as follows:

Rate	Annual Increase		No. of Customers
Rate RS	$	4,729,754	94,170
Rate GS	$	3,523,980	7,003
Rate FT-L	$	785,547	91
Rate IT	$	220,396	22
Miscellaneous	$	(88,801)	—
Total	$	9,170,876	101,286

12. There are no changes to major security holders and voting powers of Duke Energy Kentucky, Inc. that occurred during the fourth quarter 2021.

The changes in officers and directors for Duke Energy Kentucky, Inc. that occurred during the fourth quarter 2021 are as follows:

Appointments effective 11/01/21	
Cameron D. McDonald	Vice President, Chief Diversity and Inclusion Officer, Talent Agility and Acquisition
Resignations effective 11/01/21	
Cameron D. McDonald	Vice President, Human Resources, Transformation & Employee Development
There are no changes in major security holders and voting powers of Duke Energy Kentucky, Inc that occurred during the third quarter of 2021.	
The changes in officers and directors for Duke Energy Kentucky, Inc. that occurred during the third quarter of 2021 are as follows:	
Appointments effective 07/01/21	
Ariane S. Johnson	Assistant Corporate Secretary
Resignations effective 08/01/21	
Douglas F. Esamann	Advisor to the Chair, President and Chief Executive Officer
Resignations effective 07/01/21	
John B. Scheidler	Assistant Corporate Secretary
There are no changes in major security holders and voting powers of Duke Energy Kentucky, Inc that occurred during the second quarter of 2021.	
The changes in officers and directors for Duke Energy Kentucky, Inc. that occurred during the second quarter of 2021 are as follows:	
Appointments effective 05/16/21	
Dwight L. Jacobs	Senior Vice President, Supply Chain and Chief Procurement Officer
Cynthia S. Lee	Vice President, Chief Accounting Officer and Controller
Appointments effective 05/01/21	
Jessica L. Bednarcik	Senior Vice President, Environmental, Health and Safety and Coal Combustion Products
Melody Birmingham	Senior Vice President and Chief Administrative Officer
Swati V. Daji	Senior Vice President, Enterprise Strategy and Planning
Diane V. Denton	Vice President, Integrated Planning, Florida and Midwest
Paul Draovitch	Senior Vice President, Chief Regulated and Renewable Energy Officer
Douglas F. Esamann	Advisor to the Chair, President and Chief Executive Officer
Christopher M. Fallon	Senior Vice President and President, Duke Energy Sustainable Solutions
Nicholas J. Giaimo	Vice President, Financial Planning and Analysis
R. Alexander Glenn	Director
R. Alexander Glenn	Senior Vice President
Julia S. Janson	Executive Vice President
Michael Luhrs	Vice President, Integrated Grid Strategy
Louis E. Renjel	Senior Vice President, External Affairs and Communications
Regis T. Repko	Senior Vice President, Generation and Transmission Strategy
Brian D. Savoy	Executive Vice President, Chief Strategy and Commercial Officer
Harry K. Sideris	Executive Vice President, Customer Experience, Solutions, and Services
Resignations effective 05/16/21	
Dwight L. Jacobs	Senior Vice President, Chief Accounting Officer, Tax and Controller
Resignations effective 05/01/21	
Melody Birmingham	Senior Vice President, Supply Chain and Chief Procurement Officer
Cari P. Boyce	Senior Vice President, Enterprise Strategy and Planning
William E. Currens Jr.	Senior Vice President, Financial Planning and Analysis
Swati V. Daji	Senior Vice President, Customer Solutions and Strategies
Paul Draovitch	Senior Vice President, Environmental, Health and Safety and Project Management and Controls
Douglas F. Esamann	Director
Douglas F. Esamann	Executive Vice President, Energy Solutions and President, Midwest/Florida Regions and Natural Gas Business
Christopher M. Fallon	President, Duke Energy Renewables and Senior Vice President, Delivery & Operations
Julia S. Janson	Executive Vice President, External Affairs and President, Carolinas Region
Louis E. Renjel	Senior Vice President, Federal Government and Corporate Affairs
Regis T. Repko	Senior Vice President, Chief Regulated & Renewable Energy Officer
Brian D. Savoy	Senior Vice President, Chief Transformation and Administrative Officer
Harry K. Sideris	Senior Vice President, Customer Experience and Services
There are no changes in major security holders and voting powers of Duke Energy Kentucky, Inc that occurred during the first quarter of 2021.	
The changes in officers and directors for Duke Energy Kentucky, Inc. that occurred during the first quarter of 2021 are as follows:	
Appointments effective 02/01/21	
Christopher Bauer	Assistant Treasurer
Kenna Jordan	Assistant Corporate Secretary
Regis T. Repko	Senior Vice President, Chief Regulated & Renewable Energy Officer
Resignations effective 02/1/21	
Regis T. Repko	Senior Vice President and Chief Fossil/Hydro Officer
John L. Sullivan, III	Assistant Treasurer

13. N/A

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Comparative Balance Sheet (Assets And Other Debits)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	2,996,350,732	2,881,491,826
3	Construction Work in Progress (107)	200-201	96,259,188	70,446,121
4	TOTAL Utility Plant (Total of lines 2 and 3)	200-201	3,092,609,920	2,951,937,947
5	(Less) Accum. Provision for Depr., Amort., Depl. (108, 111, 115)		1,073,764,061	1,044,742,638
6	Net Utility Plant (Total of line 4 less 5)		2,018,845,859	1,907,195,309
7	Nuclear Fuel (120.1 thru 120.4, and 120.6)			
8	(Less) Accum. Provision for Amort., of Nuclear Fuel Assemblies (120.5)			
9	Nuclear Fuel (Total of line 7 less 8)			
10	Net Utility Plant (Total of lines 6 and 9)		2,018,845,859	1,907,195,309
11	Utility Plant Adjustments (116)	122		
12	Gas Stored-Base Gas (117.1)	220		
13	System Balancing Gas (117.2)	220		
14	Gas Stored in Reservoirs and Pipelines-Noncurrent (117.3)	220		
15	Gas Owed to System Gas (117.4)	220		
16	**OTHER PROPERTY AND INVESTMENTS**			
17	Nonutility Property (121)		1,247,563	1,220,439
18	(Less) Accum. Provision for Depreciation and Amortization (122)			
19	Investments in Associated Companies (123)	222-223		
20	Investments in Subsidiary Companies (123.1)	224-225		
22	Noncurrent Portion of Allowances			
23	Other Investments (124)	222-223	1,500	1,500
24	Sinking Funds (125)			
25	Depreciation Fund (126)			
26	Amortization Fund - Federal (127)			
27	Other Special Funds (128)		16,381,482	12,851,866
28	Long-Term Portion of Derivative Assets (175)		111,502	317,782
29	Long-Term Portion of Derivative Assets - Hedges (176)			

30	TOTAL Other Property and Investments (Total of lines 17-20, 22-29)		17,742,047	14,391,587
31	**CURRENT AND ACCRUED ASSETS**			
32	Cash (131)		5,482,547	4,296,974
33	Special Deposits (132-134)			
34	Working Funds (135)			
35	Temporary Cash Investments (136)	222-223		
36	Notes Receivable (141)			
37	Customer Accounts Receivable (142)		20,694,605	6,233,908
38	Other Accounts Receivable (143)		2,142,390	1,981,275
39	(Less) Accum. Provision for Uncollectible Accounts - Credit (144)		314,921	324,092
40	Notes Receivable from Associated Companies (145)		22,396,503	21,030,759
41	Accounts Receivable from Associated Companies (146)		9,106,248	2,001,212
42	Fuel Stock (151)		32,848,807	30,021,194
43	Fuel Stock Expenses Undistributed (152)			
44	Residuals (Elec) and Extracted Products (Gas) (153)			
45	Plant Materials and Operating Supplies (154)		16,707,317	17,576,107
46	Merchandise (155)			
47	Other Materials and Supplies (156)			
48	Nuclear Materials Held for Sale (157)			
49	Allowances (158.1 and 158.2)		19,189	19,921
50	(Less) Noncurrent Portion of Allowances			
51	Stores Expense Undistributed (163)		(22,522)	84,712
52	Gas Stored Underground-Current (164.1)	220		
53	Liquefied Natural Gas Stored and Held for Processing (164.2 thru 164.3)	220		
54	Prepayments (165)	230	1,293,933	428,870
55	Advances for Gas (166 thru 167)			
56	Interest and Dividends Receivable (171)			
57	Rents Receivable (172)		4,020	21,480
58	Accrued Utility Revenues (173)			
59	Miscellaneous Current and Accrued Assets (174)		10,884,227	7,863,991
60	Derivative Instrument Assets (175)		1,635,966	1,379,378
61	(Less) Long-Term Portion of Derivative Instrument Assets (175)		111,502	317,782
62	Derivative Instrument Assets - Hedges (176)			

63	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
64	TOTAL Current and Accrued Assets (Total of lines 32 thru 63)		122,766,807	92,297,907
65	**DEFERRED DEBITS**			
66	Unamortized Debt Expense (181)		2,718,168	3,114,783
67	Extraordinary Property Losses (182.1)	230		
68	Unrecovered Plant and Regulatory Study Costs (182.2)	230		
69	Other Regulatory Assets (182.3)	232	140,633,411	136,150,402
70	Preliminary Survey and Investigation Charges (Electric)(183)		389,939	447,199
71	Preliminary Survey and Investigation Charges (Gas)(183.1 and 183.2)			
72	Clearing Accounts (184)		5	4
73	Temporary Facilities (185)			
74	Miscellaneous Deferred Debits (186)	233	2,215,689	2,156,140
75	Deferred Losses from Disposition of Utility Plant (187)			
76	Research, Development, and Demonstration Expend. (188)			
77	Unamortized Loss on Reacquired Debt (189)		394,481	517,204
78	Accumulated Deferred Income Taxes (190)	234-235	70,722,124	73,220,723
79	Unrecovered Purchased Gas Costs (191)		1,128,482	(3,514,021)
80	TOTAL Deferred Debits (Total of lines 66 thru 79)		218,202,299	212,092,434
81	TOTAL Assets and Other Debits (Total of lines 10-15,30,64,and 80)		2,377,557,012	2,225,977,237

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Comparative Balance Sheet (Liabilities and Other Credits)

Line No.	Title of Account (a)	Reference Page Number (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	8,779,995	8,779,995
3	Preferred Stock Issued (204)	250-251		
4	Capital Stock Subscribed (202, 205)	252		
5	Stock Liability for Conversion (203, 206)	252		
6	Premium on Capital Stock (207)	252	18,838,946.00	18,838,946
7	Other Paid-In Capital (208-211)	253	273,655,189	223,655,189
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254		
11	Retained Earnings (215, 215.1, 216)	118-119	520,368,338	466,962,758
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119		
13	(Less) Reacquired Capital Stock (217)	250-251		
14	Accumulated Other Comprehensive Income (219)	117		
15	TOTAL Proprietary Capital (Total of lines 2 thru 14)		821,642,468	718,236,888
16	**LONG TERM DEBT**			
17	Bonds (221)	256-257		
18	(Less) Reacquired Bonds (222)	256-257		
19	Advances from Associated Companies (223)	256-257	25,000,000	25,000,000
20	Other Long-Term Debt (224)	256-257	706,720,000	706,720,000
21	Unamortized Premium on Long-Term Debt (225)	258-259		
22	(Less) Unamortized Discount on Long-Term Debt-Dr (226)	258-259	174,038	186,301
23	(Less) Current Portion of Long-Term Debt			
24	TOTAL Long-Term Debt (Total of lines 17 thru 23)		731,545,962	731,533,699
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases-Noncurrent (227)		8,378,503	8,696,322
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		(79,788)	(83,933)

29	Accumulated Provision for Pensions and Benefits (228.3)		30,843,612	31,431,080
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)			
32	Long-Term Portion of Derivative Instrument Liabilities		3,693,879	5,290,232
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		93,282,532	76,111,813
35	TOTAL Other Noncurrent Liabilities (Total of lines 26 thru 34)		136,118,738	121,445,514
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Current Portion of Long-Term Debt			
38	Notes Payable (231)			
39	Accounts Payable (232)		45,980,386	41,066,542
40	Notes Payable to Associated Companies (233)		102,596,001	75,472,000
41	Accounts Payable to Associated Companies (234)		14,614,111	16,595,167
42	Customer Deposits (235)		9,122,676	9,136,959
43	Taxes Accrued (236)	262-263	9,222,510	18,784,698
44	Interest Accrued (237)		7,529,336	7,611,627
45	Dividends Declared (238)			
46	Matured Long-Term Debt (239)			
47	Matured Interest (240)			
48	Tax Collections Payable (241)		2,940,535	2,099,990
49	Miscellaneous Current and Accrued Liabilities (242)	268	5,943,819	8,260,083
50	Obligations Under Capital Leases-Current (243)		317,820	292,937
51	Derivative Instrument Liabilities (244)		4,644,858	6,298,964
52	(Less) Long-Term Portion of Derivative Instrument Liabilities		3,693,879	5,290,232
53	Derivative Instrument Liabilities - Hedges (245)			
54	(Less) Long-Term Portion of Derivative Instrument Liabilities - Hedges			
55	TOTAL Current and Accrued Liabilities (Total of lines 37 thru 54)		199,218,173	180,328,735
56	**DEFERRED CREDITS**			
57	Customer Advances for Construction (252)		1,645,440	1,595,027
58	Accumulated Deferred Investment Tax Credits (255)		3,559,977	3,618,035
59	Deferred Gains from Disposition of Utility Plant (256)			
60	Other Deferred Credits (253)	269	14,246,484	14,622,647
61	Other Regulatory Liabilities (254)	278	130,898,991	138,994,834

62	Unamortized Gain on Reacquired Debt (257)	260		
63	Accumulated Deferred Income Taxes - Accelerated Amortization (281)			
64	Accumulated Deferred Income Taxes - Other Property (282)		301,962,482	285,156,597
65	Accumulated Deferred Income Taxes - Other (283)		36,718,297	30,445,261
66	TOTAL Deferred Credits (Total of lines 57 thru 65)		489,031,671	474,432,401
67	TOTAL Liabilities and Other Credits (Total of lines 15,24,35,55,and 66)		2,377,557,012	2,225,977,237

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Statement of Income

Quarterly

1. Enter in column (d) the balance for the reporting quarter and in column (e) the balance for the same three month period for the prior year.
2. 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 (k) the quarter to date amounts for other utility function for the current year quarter.
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 (k) the quarter to date amounts for other utility function for the prior year quarter.
4. If additional columns are needed place them in a footnote.

Annual or Quarterly, if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.
9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11. Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stockholders 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.

Line No.	Title of Account (a)	Reference Page Number (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)	Elec. Utility Current Year to Date (in dollars) (g)	Elec. Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Gas Operating Revenues (400)	300-301	514,640,093	445,665,255			399,019,808	346,892,088	115,620,285	98,773,167		
3	Operating Expenses											
4	Operation Expenses (401)	317-325	286,402,185	235,673,671			225,147,072	188,781,980	61,255,113	46,891,691		
5	Maintenance Expenses (402)	317-325	38,272,692	35,779,342			36,185,319	33,864,124	2,087,373	1,915,218		
6	Depreciation Expense (403)	336-338	64,618,518	61,396,656			48,640,753	46,871,823	15,977,765	14,524,833		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-338										
8	Amort. & Depl. of Utility Plant (404-405)	336-338	7,862,366	7,471,556			3,543,320	3,600,538	4,319,046	3,871,018		
9	Amortization of Utility Plant Acu. Adjustment (406)	336-338										
10	Amort. of Prop. Losses, Unrecovered Plant and Reg. Study Costs (407.1)											
11	Amortization of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)		12,706,512	10,835,750			10,201,756	9,993,465	2,504,756	842,285		
13	(Less) Regulatory Credits (407.4)		7,000,556	6,557,984			6,897,985	6,444,590	102,571	113,394		
14	Taxes Other Than Income Taxes (408.1)	262-263	20,498,702	16,918,072			15,842,108	13,169,657	4,656,594	3,748,415		

15	Income Taxes-Federal (409.1)	262-263	(8,052,386)	2,044,705			(8,317,550)	(498,211)	265,164	2,542,916		
16	Income Taxes-Other (409.1)	262-263	(2,502,787)	271,995			(2,533,237)	329,389	30,450	(57,394)		
17	Provision of Deferred Income Taxes (410.1)	234-235	59,111,911	41,108,598			47,582,356	32,009,110	11,529,555	9,099,488		
18	(Less) Provision for Deferred Income Taxes-Credit (411.1)	234-235	38,405,762	34,315,896			30,003,029	26,622,848	8,402,733	7,693,048		
19	Investment Tax Credit Adjustment-Net (411.4)		(58,058)	(61,175)			(428)	(428)	(57,630)	(60,747)		
20	(Less) Gains from Disposition of Utility Plant (411.6)											
21	Losses from Disposition of Utility Plant (411.7)											
22	(Less) Gains from Disposition of Allowances (411.8)		183,883	59,444			183,883	59,444				
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)											
25	TOTAL Utility Operating Expenses (Total of lines 4 thru 24)		433,269,454	370,505,846			339,206,572	294,994,565	94,062,882	75,511,281		
26	Net Utility Operating Income (Total of lines 2 less 25)		81,370,639	75,159,409			59,813,236	51,897,523	21,557,403	23,261,886		
28	OTHER INCOME AND DEDUCTIONS											
29	Other Income											
30	Nonutilty Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,418,388	1,300,789								
32	(Less) Costs and Expense of Merchandising, Job & Contract Work (416)		132,598	79,842								
33	Revenues From Nonutility Operations (417)		(5)	(50)								
34	(Less) Expenses of Nonutility Operations (417.1)		65,209	56,068								
35	Nonoperating Rental Income (418)											
36	Equity in Earnings of Subsidiary Companies (418.1)	119										
37	Interest and Dividend Income (419)		981,836	965,254								
38	Allowance for Other Funds Used During Construction (419.1)		1,259,856	(124,641)								
39	Miscellaneous Nonoperating Income (421)		977,722	1,059,499								
40	Gain on Disposition of Property (421.1)											
41	TOTAL Other Income (Total of lines 31 thru 40)		4,439,990	3,064,941								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)											

44	Miscellaneous Amortization (425)											
45	Donations (426.1)	340	413,987	255,853								
46	Life Insurance (426.2)		(9,857)	(2,326)								
47	Penalties (426.3)		166,667	2,500								
48	Expenditures for Certain Civic, Political and Related Activities (426.4)		454,776	495,762								
49	Other Deductions (426.5)		3,817,077	1,218,343								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)	340	4,842,650	1,970,132								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262-263	(1,176)	104,393								
53	Income Taxes-Federal (409.2)	262-263	1,098,161	2,180,902								
54	Income Taxes-Other (409.2)	262-263	273,404	544,528								
55	Provision for Deferred Income Taxes (410.2)	234-235	514,292	122,704								
56	(Less) Provision for Deferred Income Taxes-Credit (411.2)	234-235	1,918,797	2,188,314								
57	Investment Tax Credit Adjustments-Net (411.5)											
58	(Less) Investment Tax Credits (420)											
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		(34,116)	764,213								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		(368,544)	330,596								
61	INTEREST CHARGES											
62	Interest on Long-Term Debt (427)		25,860,084	24,665,700								
63	Amortization of Debt Disc. and Expense (428)	258-259	555,657	392,830								
64	Amortization of Loss on Reacquired Debt (428.1)		122,723	171,778								
65	(Less) Amortization of Premium on Debt-Credit (429)	258-259										
66	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1)											
67	Interest on Debt to Associated Companies (430)	340	141,453	755,884								
68	Other Interest Expense (431)	340	1,366,279	1,360,229								
69	(Less) Allowance for Borrowed Funds Used During Construction-Credit (432)		449,681	(288)								
70	Net Interest Charges (Total of lines 62 thru 69)		27,596,515	27,346,709								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		53,405,580	48,143,296								
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)		53,405,580	48,143,296								

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Statement of Accumulated Comprehensive Income and Hedging Activities

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

Line No.	Item (a)	Unrealized Gains and Losses on available-for-sale securities (b)	Minimum Pension liabililty Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Insert Footnote at Line 1 to specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 114, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year									
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income									
3	Preceding Quarter/Year to Date Changes in Fair Value									
4	Total (lines 2 and 3)								48,143,296	48,143,296
5	Balance of Account 219 at End of Preceding Quarter/Year									
6	Balance of Account 219 at Beginning of Current Year									
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income									
8	Current Quarter/Year to Date Changes in Fair Value									
9	Total (lines 7 and 8)								53,405,580	53,405,580
10	Balance of Account 219 at End of Current Quarter/Year									

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Statement of Retained Earnings

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
3. State the purpose and amount for each reservation or appropriation of retained earnings.
4. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
5. Show dividends for each class and series of capital stock.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS			
1	Balance-Beginning of Period		466,962,758	418,819,462
2	Changes (Identify by prescribed retained earnings accounts)			
3	Adjustments to Retained Earnings (Account 439)			
3.1	TOTAL Credits to Retained Earnings (Account 439) (footnote details)			
3.2	TOTAL Debits to Retained Earnings (Account 439) (footnote details)			
3.3	Balance Transferred from Income (Acct 433 less Acct 418.1) 400-403		53,405,580	48,143,296
4	Adjustments to Retained Earnings Credit (Debit)			
6	Balance Transferred from Income (Account 433 less Account 418.1)			
7	Appropriations of Retained Earnings (Account 436)			
7.1	TOTAL Appropriations of Retained Earnings (Account 436) (footnote details)			
8	Appropriations of Retained Earnings Amount			
9	Dividends Declared-Preferred Stock (Account 437)			
9.1	TOTAL Dividends Declared-Preferred Stock (Account 437) (footnote details)			
10	Dividends Declared-Preferred Stock Amount			
11	Dividends Declared-Common Stock (Account 438)			
11.1	TOTAL Dividends Declared-Common Stook (Account 438) (footnote details)			
12	Dividends Declared-Common Stock Amount			
13	Transfers from Account 216.1, Unappropriated Undistributed Subsidiary Earnings			
14	Balance-End of Period (Total of lines 1, 4, 5, 6, 8, 10, 12, and 13)		520,368,338	466,962,758
15	APPROPRIATED RETAINED EARNINGS (Account 215)			
16	TOTAL Appropriated Retained Earnings (Account 215) (footnote details)			
17	APPROPRIATED RETAINED EARNINGS-AMORTIZATION RESERVE, FEDERAL (Account 215.1)			
18	TOTAL Appropriated Retained Earnings-Amortization Reserve, Federal (Account 215.1)			

19	TOTAL Appropriated Retained Earnings (Accounts 215, 215.1) (Total of lines of 16 and 18)			
20	TOTAL Retained Earnings (Accounts 215, 215.1, 216) (Total of lines 14 and 19)		520,368,338	466,962,758
21	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)			
	Report only on an Annual Basis no Quarterly			
22	Balance-Beginning of Year (Debit or Credit)			
23	Equity in Earnings for Year (Credit) (Account 418.1)			
24	(Less) Dividends Received (Debit)			
25	Other Changes (Explain)			
25.1	Other Changes (Explain)			
26	Balance-End of Year			

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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 27) 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 Instructions 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 114)	53,405,580	48,143,296
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	64,618,518	61,396,656
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of (Specify)		
5.2	Plant Items	10,133,866	7,471,556
5.3	Debt Discount, Premium, Expense, and Loss on Reacquired Debt	678,380	564,608
6	Deferred Income Taxes (Net)	19,301,644	4,727,092
7	Investment Tax Credit Adjustments (Net)	(58,058)	(61,175)
8	Net (Increase) Decrease in Receivables	(21,718,559)	7,295,872
9	Net (Increase) Decrease in Inventory	(1,851,589)	781,424
10	Net (Increase) Decrease in Allowances Inventory	732	933
11	Net Increase (Decrease) in Payables and Accrued Expenses	(18,305,865)	13,717,391
12	Net (Increase) Decrease in Other Regulatory Assets	(7,585,119)	(2,311,411)
13	Net Increase (Decrease) in Other Regulatory Liabilities	(2,479,911)	(1,214,007)
14	(Less) Allowance for Other Funds Used During Construction	1,259,856	(124,641)
15	(Less) Undistributed Earnings from Subsidiary Companies		
16	Other Adjustments to Cash Flows from Operating Activities		
16.1	Other Adjustments to Cash Flows from Operating Activities		
16.2	Special funds	(2,197,548)	(910,762)
16.3	Prepayments	5,479,620	1,008,692
16.4	Miscellaneous Current and Accrued Assets	(445,803)	210,540
16.5	Preliminary Survey and Investigation Charges	57,260	(91,894)

16.6	Clearing Accounts		4,584
16.7	Miscellaneous Deferred Debits	(59,549)	379,620
16.8	Unrecovered Purchased Gas Costs	(4,642,503)	(784,818)
16.9	Obligations Under Capital Leases - Noncurrent	(317,819)	(292,937)
16.10	Accumulated Provisions	369,326	(62,781)
16.11	Contribution to Pension Plan		
16.12	Customer Advances for Construction	50,413	(10,172)
16.13	Other Deferred Credits	(376,163)	285,734
16.14	Derivative Instruments	148,527	1,006,439
16.15	Net Utility Plant and Nonutility Property	12,616,650	7,138,729
16.16	Debt Expenses	(23,500)	(314,125)
16.17	Deferred Income Taxes	391,237	219,894
18	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 16)	105,929,911	148,423,619
20	Cash Flows from Investment Activities:		
21	Construction and Acquisition of Plant (including land):		
22	Gross Additions to Utility Plant (less nuclear fuel)	(181,350,003)	(232,636,624)
23	Gross Additions to Nuclear Fuel		
24	Gross Additions to Common Utility Plant	(289,169)	(1,376,428)
25	Gross Additions to Nonutility Plant		
26	(Less) Allowance for Other Funds Used During Construction	(1,259,856)	124,641
27	Other Construction and Acquisition of Plant, Investment Activities		
27.1	Other Construction and Acquisition of Plant, Investment Activities		
28	Cash Outflows for Plant (Total of lines 22 thru 27)	(180,379,316)	(234,137,693)
30	Acquisition of Other Noncurrent Assets (d)		
31	Proceeds from Disposal of Noncurrent Assets (d)		
33	Investments in and Advances to Associated and Subsidiary Companies		
34	Contributions and Advances from Associated and Subsidiary Companies		
36	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
38	Purchase of Investment Securities (a)		
39	Proceeds from Sales of Investment Securities (a)		
40	Loan Made or Purchased		
41	Collections on Loans		
43	Net (Increase) Decrease in Receivables	(1,365,744)	(5,002,000)

44	Net (Increase) Decrease in Inventory		
45	Net (Increase) Decrease in Allowances Held for Speculation		
46	Net Increase (Decrease) in Payables and Accrued Expenses		
47	Other Adjustments to Cash Flows from Investment Activities:		
47.1	Other Adjustments to Cash Flows from Investment Activities:		
49	Net Cash Provided by (Used in) Investing Activities (Total of lines 28 thru 47)	(181,745,060)	(239,139,693)
51	Cash Flows from Financing Activities:		
52	Proceeds from Issuance of:		
53	Proceeds from Issuance of Long-Term Debt (b)	50,000,000	70,000,000
54	Proceeds from Issuance of Preferred Stock		
55	Proceeds from Issuance of Common Stock		
56	Net Increase in Debt (Long Term Advances)		
56.1	Net Increase in Debt (Long Term Advances)		
56.2	Contribution from Parent	50,000,000	25,000,000
57	Net Increase in Short-term Debt (c)		
59	Cash Provided by Outside Sources (Total of lines 53 thru 58)	100,000,000	95,000,000
61	Payments for Retirement		
62	Payments for Retirement of Long-Term Debt (b)	(50,014,560)	
63	Payments for Retirement of Preferred Stock		
64	Payments for Retirement of Common Stock		
65	Other Retirements		
65.1	Intercompany Moneypool Payable	27,124,001	(7,037,000)
66	Net Decrease in Short-Term Debt (c)		
67	Other Adjustments to Financing Cash Flows		
67.1	Other Adjustments to Financing Cash Flows	(108,719)	(95,616)
68	Dividends on Preferred Stock		
69	Dividends on Common Stock		
70	Net Cash Provided by (Used in) Financing Activities (Total of lines 59 thru 69)	77,000,722	87,867,384
73	Net Increase (Decrease) in Cash and Cash Equivalents		
74	(Total of line 18, 49 and 71)	1,185,573	(2,848,690)
76	Cash and Cash Equivalents at Beginning of Period	[(a)]4,296,974	7,145,664
78	Cash and Cash Equivalents at End of Period	[(b)]5,482,547	[(c)]4,296,974

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: CashAndCashEquivalents

	YTD December 2021	YTD December 2020
Supplemental Disclosures (in thousands)		
Cash paid for interest, net of amount Capital	$ 25,688	$ 24,857
Cash paid / (refunded) for income taxes	$ 2,019	$ 1,822
Significant non-cash transactions (in thousands)		
AFUDC - equity component	$ 1,260	$ (125)
Accrued capital expenditures	$ 28,490	$ 24,529
Cash and Cash Equivalents at End of period:		
Cash (131)	$ 5,482,547	$ 4,296,974
Working Funds (135)	$ 0	$ 0
Temporary Cash Investments (136)	$ 0	$ 0
	$ 5,482,547	$ 4,296,974

(b) Concept: CashAndCashEquivalents

	YTD December 2021	YTD December 2020
Supplemental Disclosures (in thousands)		
Cash paid for interest, net of amount Capital	$ 25,688	$ 24,857
Cash paid / (refunded) for income taxes	$ 2,019	$ 1,822
Significant non-cash transactions (in thousands)		
AFUDC - equity component	$ 1,260	$ (125)
Accrued capital expenditures	$ 28,490	$ 24,529
Cash and Cash Equivalents at End of period:		
Cash (131)	$ 5,482,547	$ 4,296,974
Working Funds (135)	$ 0	$ 0
Temporary Cash Investments (136)	$ 0	$ 0
	$ 5,482,547	$ 4,296,974

(c) Concept: CashAndCashEquivalents

	YTD December 2021	YTD December 2020
Supplemental Disclosures (in thousands)		
Cash paid for interest, net of amount Capital	$ 25,688	$ 24,857
Cash paid / (refunded) for income taxes	$ 2,019	$ 1,822
Significant non-cash transactions (in thousands)		
AFUDC - equity component	$ 1,260	$ (125)
Accrued capital expenditures	$ 28,490	$ 24,529
Cash and Cash Equivalents at End of period:		
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Temporary Cash Investments (136)	$ 0	$ 0
	$ 5,482,547	$ 4,296,974

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Notes to Financial Statements

1. Provide important disclosures regarding the Balance Sheet, Statement of Income for the Year, Statement of Retained Earnings for the Year, and Statement of Cash Flow, or any account thereof. Classify the disclosures according to each financial statement, providing a subheading for each statement except where a disclosure is applicable to more than one statement. The disclosures must be on the same subject matters and in the same level of detail that would be required if the respondent issued general purpose financial statements to the public or shareholders.
2. Furnish details as to any significant contingent assets or liabilities existing at year end, and briefly explain any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or a claim for refund of income taxes of a material amount initiated by the utility. Also, briefly explain any dividends in arrears on cumulative preferred stock.
3. Furnish details on the respondent's pension plans, post-retirement benefits other than pensions (PBOP) plans, and post-employment benefit plans as required by instruction no. 1 and, in addition, disclose for each individual plan the current year's cash contributions. Furnish details on the accounting for the plans and any changes in the method of accounting for them. Include details on the accounting for transition obligations or assets, gains or losses, the amounts deferred and the expected recovery periods. Also, disclose any current year's plan or trust curtailments, terminations, transfers, or reversions of assets. Entities that participate in multiemployer postretirement benefit plans (e.g. parent company sponsored pension plans) disclose in addition to the required disclosures for the consolidated plan, (1) the amount of cost recognized in the respondent's financial statements for each plan for the period presented, and (2) the basis for determining the respondent's share of the total plan costs.
4. Furnish details on the respondent's asset retirement obligations (ARO) as required by instruction no. 1 and, in addition, disclose the amounts recovered through rates to settle such obligations. Identify any mechanism or account in which recovered funds are being placed (i.e. trust funds, insurance policies, surety bonds). Furnish details on the accounting for the asset retirement obligations and any changes in the measurement or method of accounting for the obligations. Include details on the accounting for settlement of the obligations and any gains or losses expected or incurred on the settlement.
5. Provide a list of all environmental credits received during the reporting period.
6. Provide a summary of revenues and expenses for each tracked cost and special surcharge.
7. Where Account 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 item. See General Instruction 17 of the Uniform System of Accounts.
8. Explain concisely any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
9. Disclose details on any significant financial changes during the reporting year to the respondent or the respondent's consolidated group that directly affect the respondent's gas pipeline operations, including: sales, transfers or mergers of affiliates, investments in new partnerships, sales of gas pipeline facilities or the sale of ownership interests in the gas pipeline to limited partnerships, investments in related industries (i.e., production, gathering), major pipeline investments, acquisitions by the parent corporation(s), and distributions of capital.
10. Explain concisely unsettled rate proceedings where a contingency exists such that the company may need to refund a material amount to the utility's customers or that the utility may receive a material refund with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects and explain the major factors that affect the rights of the utility to retain such revenues or to recover amounts paid with respect to power and gas purchases.
11. Explain concisely significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and summarize the adjustments made to balance sheet, income, and expense accounts.
12. Explain concisely only those significant 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 approximate dollar effect of such changes.
13. 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.
14. 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.
15. 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.

This Federal Energy Regulatory Commission (FERC) Form 2 has been prepared in conformity with the requirements of the FERC 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 in the United States of America (GAAP). The following areas represent the significant differences between the Uniform System of Accounts and GAAP:

- GAAP requires that public business enterprises report certain information about operating segments in complete sets of financial statements of the enterprise and certain information about their products and services, which are not required for FERC reporting purposes.
- GAAP requires that majority-owned subsidiaries be consolidated for financial reporting purposes. FERC requires that majority-owned subsidiaries be separately reported as Investment in Subsidiary Companies, unless an appropriate waiver has been granted by FERC.
- FERC requires that income or losses of an unusual nature and infrequent occurrence, which would significantly distort the current year's income, be recorded as extraordinary income or deductions, respectively.
- GAAP requires that removal and nuclear decommissioning costs for property that does not have an associated legal retirement obligation be presented as a regulatory liability on the Balance Sheet. These costs are presented as accumulated depreciation on the Balance Sheet for FERC reporting purposes.
- GAAP requires the regulatory assets and liabilities resulting from the implementation of ASC 740-10 (formerly SFAS No. 109) be presented as a net amount on the balance sheet. For FERC reporting purposes, these assets and liabilities are presented separately and are included in the Other Regulatory Asset and Other Regulatory Liability line items.
- GAAP requires that the current portion of regulatory assets and regulatory liabilities be reported as current assets and current liabilities, respectively, on the Balance Sheet. FERC requires that the current portion of regulatory assets and liabilities be reported as Regulatory Assets within Deferred Debits and Regulatory Liabilities within Deferred Credits, respectively.
- GAAP requires that any deferred costs associated with a specific debt issuance be presented as a reduction to debt on the Balance Sheet. FERC requires any Unamortized Debt Expense to be separately stated as a Deferred Debit on the Balance Sheet.
- GAAP requires that certain account balances within financial statement line items which are not in the natural position for that line item (e.g. an account within Accounts Receivable with a credit balance) be reclassed to the appropriate side of the Balance Sheet. FERC does not require certain accounts which are not in a natural position for their respective

line item to be reclassed, as long as the line item in total is in its natural position.

- GAAP requires that regulated assets that are abandoned or retired early, including the cost of the asset and its associated accumulated depreciation, be reclassified to a separate regulatory asset on the Balance Sheet. For FERC reporting purposes, those assets which have been abandoned but are still operating are maintained in their original balance sheet accounts.
- GAAP requires that the current portion of Asset Retirement Obligations be reported as current liabilities on the Balance Sheet. For FERC reporting purposes, these liabilities are not reported separately and are reflected as Asset Retirement Obligations within the Other Noncurrent Liabilities section of the Balance Sheet.
- GAAP requires service cost related to pensions and Post-Retirement Benefits Other Than Pensions (PBOP) to be reported with other compensation costs arising from services rendered by employees during the period and included in a subtotal of income from operations on the income statement. Non-service cost components are presented separately outside the subtotal of income from operations on the income statement. For FERC reporting purposes, costs related to pensions and PBOP is included in the Net Utility Operating Income of the income statement.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

NATURE OF OPERATIONS AND BASIS OF PRESENTATION

Duke Energy Kentucky is a combination electric and natural gas regulated public utility company that provides service in northern Kentucky. Duke Energy Kentucky's principal lines of business include generation, transmission, distribution and sale of electricity, as well as the transportation and sale of natural gas. Duke Energy Kentucky is subject to the regulatory provisions of the KPSC and the FERC. Duke Energy Kentucky's common stock is wholly owned by Duke Energy Ohio, Inc., an indirect wholly owned subsidiary of Duke Energy.

Certain prior year amounts have been reclassified to conform to the current year presentation.

Other Current Assets and Liabilities

The following table provides a description of amounts included in Other within Current Assets or Current Liabilities that exceed 5% of total Current Assets or Current Liabilities on the Duke Energy Kentucky Balance Sheets at either December 31, 2021, or 2020.

		December 31,	
(in thousands)	**Location**	**2021**	**2020**
Income Taxes Receivable	**Current Assets**	**$ 8,717**	$ 140

SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

In preparing financial statements that conform to GAAP, Duke Energy Kentucky must make estimates and assumptions that affect the reported amounts of assets and liabilities, the reported amounts of revenues and expenses and the disclosure of contingent assets and liabilities at the date of the financial statements. Actual results could differ from those estimates.

Regulatory Accounting

The majority of Duke Energy Kentucky's operations are subject to price regulation for the sale of electricity and natural gas by the KPSC or FERC. When prices are set on the basis of specific costs of the regulated operations and an effective franchise is in place such that sufficient natural gas or electric services can be sold to recover those costs, Duke Energy Kentucky applies regulatory accounting. Regulatory accounting changes the timing of the recognition of costs or revenues relative to a company that does not apply regulatory accounting. As a result, regulatory assets and regulatory liabilities are recognized on the Balance Sheets and are amortized consistent with the treatment of the related cost in the ratemaking process. Regulatory assets are reviewed for recoverability each reporting period. If a regulatory asset is no longer deemed probable of recovery, the deferred cost is charged to earnings. See Note 2 for further information.

Duke Energy Kentucky utilizes cost-tracking mechanisms, commonly referred to as fuel adjustment clauses or purchased gas adjustment clauses. These clauses allow for the recovery of fuel and fuel-related costs, portions of purchased power, natural gas costs and hedging costs through surcharges on customer rates. The difference between the costs incurred and the surcharge revenues is recorded either as an adjustment to Operating Revenues, Operating Expenses - Fuel used in electric generation and purchased power or Operating Expenses - Cost of natural gas on the Statements of Operations with an off-setting impact on regulatory assets or regulatory liabilities.

Cash and Cash Equivalents

All highly liquid investments with maturities of three months or less at the date of acquisition are considered cash equivalents.

Inventory

Inventory related to regulated operations is valued at historical cost. Inventory is charged to expense or capitalized to property, plant and equipment when issued, primarily using the average cost method. Excess or obsolete inventory is written-down to the lower of cost or net realizable value. Once inventory has been written-down, it creates a new cost basis for the inventory that is not subsequently written-up. Provisions for inventory write-offs were not material at December 31, 2021, and 2020. The components of inventory are presented in the table below.

	December 31,	
(in thousands)	**2021**	**2020**
Materials and supplies	**$ 16,685**	$ 17,661
Coal	**18,978**	16,052
Natural gas, oil and other	**13,871**	13,969
Total inventory	**$ 49,534**	$ 47,682

Long-Lived Asset Impairments

Duke Energy Kentucky evaluates long-lived assets for impairment when circumstances indicate the carrying value of those assets may not be recoverable. An impairment exists when a long-lived asset's carrying value exceeds the estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. The estimated cash flows may be based on alternative expected outcomes that are probability weighted. If the carrying value of the long-lived asset is not recoverable based on these estimated future undiscounted cash flows, the carrying value of the asset is written-down to its then-current estimated fair value and an impairment charge is recognized.

Duke Energy Kentucky assesses the fair value of long-lived assets using various methods, including recent comparable third-party sales, internally developed discounted cash flow analysis and analysis from outside advisors. Triggering events to reassess cash flows may include, but are not limited to, significant changes in commodity prices, the condition of an asset or management's interest in selling the asset.

Property, Plant and Equipment

Property, plant and equipment are stated at the lower of depreciated historical cost net of any disallowances or fair value, if impaired. Duke Energy Kentucky capitalizes all construction-related direct labor and material costs, as well as indirect construction costs such as general engineering, taxes and financing costs. See "Allowance for Funds Used During Construction and Interest Capitalized" below for information on capitalized financing costs. Costs of renewals and betterments that extend the useful life of property, plant and equipment are also capitalized. The cost of repairs, replacements and major maintenance projects, which do not extend the useful life or increase the expected output of the asset, are expensed as incurred. Depreciation is generally computed over the estimated useful life of the asset using the composite straight-line method. Depreciation studies are conducted periodically to update composite rates and are approved by the KPSC and/or the FERC when required. The composite weighted average depreciation rate was 2.4% for the years ended December 31, 2021, and 2020.

In general, when Duke Energy Kentucky retires its regulated property, plant and equipment, the original cost plus the cost of retirement, less salvage value and any depreciation already recognized, is charged to accumulated depreciation. However, when it becomes probable a regulated asset will be retired substantially in advance of its original expected useful life or will be abandoned, the cost of the asset and the corresponding accumulated depreciation is recognized as a separate asset. If the asset is still in operation, the net amount is classified as Generation facilities to be retired, net on the Balance Sheets. If the asset is no longer operating, the net amount is classified in Regulatory assets on the Balance Sheets if deemed recoverable (see discussion of long-lived asset impairments above). The carrying value of the asset is based on historical cost if Duke Energy Kentucky is allowed to recover the remaining net book value and a return equal to at least the incremental borrowing rate. If not, an impairment is recognized to the extent the net book value of the asset exceeds the present value of future revenues discounted at the incremental borrowing rate.

When Duke Energy Kentucky sells entire regulated operating units, the original cost and accumulated depreciation and amortization balances are removed from Property, Plant and Equipment on the Balance Sheets. Any gain or loss is recorded in earnings, unless otherwise required by the KPSC and/or the FERC. See Note 7 for further information.

Leases

Duke Energy Kentucky determines if an arrangement is a lease at contract inception based on whether the arrangement involves the use of a physically distinct identified asset and whether Duke Energy Kentucky has the right to obtain substantially all of the economic benefits from the use of the asset throughout the period as well as the right to direct use of the asset. As a policy election, Duke Energy Kentucky does not evaluate arrangements with initial contract terms of less than one year as leases.

Operating leases are included in Operating lease ROU assets, net, Other current liabilities and Operating lease liabilities on the Balance Sheets.

For lessee and lessor arrangements, Duke Energy Kentucky has elected a policy to not separate lease and non-lease components for all asset classes. For lessor arrangements, lease and non-lease components are only combined under one arrangement and accounted for under the lease accounting framework if the non-lease components are not the predominant component of the arrangement and the lease component would be classified as an operating lease.

Allowance for Funds Used During Construction and Interest Capitalized

For regulated operations, the debt and equity costs of financing the construction of property, plant and equipment are reflected as AFUDC and capitalized as a component of the cost of property, plant and equipment. AFUDC equity is reported on the Statements of Operations as non-cash income in Other Income and Expenses, net. AFUDC debt is reported as a non-cash offset to Interest Expense on the Statements of Operations. After construction is completed, Duke Energy Kentucky is permitted to recover these costs through their inclusion in rate base and the corresponding subsequent depreciation or amortization of those regulated assets.

AFUDC equity, a permanent difference for income taxes, reduces the effective tax rate when capitalized and increases the effective tax rate when depreciated or amortized. See Note 15 for additional information.

Asset Retirement Obligations

AROs are recognized for legal obligations associated with the retirement of property, plant and equipment. Substantially all AROs are related to regulated operations. When recording an ARO, the present value of the projected liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The liability is accreted over time. For operating plants, the present value of the liability is added to the cost of the associated asset and depreciated over the remaining life of the asset. For retired plants, the present value of the liability is recorded as a regulatory asset unless determined not to be probable of recovery.

The present value of the initial obligation and subsequent updates are based on discounted cash flows, which include estimates regarding timing of future cash flows, selection of discount rates and cost escalation rates, among other factors. These estimates are subject to change. Depreciation expense is adjusted prospectively for any changes to the carrying amount of the associated asset. Duke Energy Kentucky receives amounts to fund the cost of the ARO from regulated revenues. As a result, amounts recovered in regulated revenues, accretion expense and depreciation of the associated asset are netted and deferred as a regulatory asset or regulatory liability.

Obligations for closure of ash basins are based upon discounted cash flows of estimated costs for site-specific plans, if known, or probability weightings of the potential closure methods if the closure plans are under development and multiple closure options are being considered and evaluated on a site-by-site basis. See Note 6 for further information.

Accounts Payable

During 2020, Duke Energy established a supply chain finance program (the "program") with a global financial institution. Duke Energy Kentucky is a participant in this enterprise-wide program offered to suppliers. The program is voluntary and allows Duke Energy Kentucky suppliers, at their sole discretion, to sell their receivables from Duke Energy Kentucky to the financial institution at a rate that leverages Duke Energy Kentucky's credit rating and, which may result in favorable terms compared to the rate available to the supplier on their own credit rating. Suppliers participating in the program determine at their sole discretion which invoices they will sell to the financial institution. Suppliers' decisions on which invoices are sold do not impact Duke Energy Kentucky's payment terms, which are based on commercial terms negotiated between Duke Energy Kentucky and the supplier regardless of program participation. The commercial terms negotiated between Duke Energy Kentucky and its suppliers are consistent regardless of whether the supplier elects to participate in the program. Duke Energy Kentucky does not issue any guarantees with respect to the program and does not participate in negotiations between suppliers and the financial institution. Duke Energy Kentucky does not have an economic interest in the supplier's decision to participate in the program and receives no interest, fees or other benefit from the financial institution based on supplier participation in the program.

Suppliers invoices sold to the financial institution under the program totaled $0 and $1.8 million for the years ended December 31, 2021, and 2020, respectively, for Duke Energy Kentucky. All activity related to amounts due to suppliers who elected to participate in the program are included within Net cash provided by operating activities on the Statements of Cash Flows.

Revenue Recognition

Duke Energy Kentucky recognizes revenue as customers obtain control of promised goods and services in an amount that reflects consideration expected in exchange for those goods or services. Generally, the delivery of electricity and natural gas results in the transfer of control to customers at the time the commodity is delivered and the amount of revenue recognized is equal to the amount billed to each customer, including estimated volumes delivered when billings have not yet occurred. See Note 13 for further information.

Derivatives and Hedging

Derivative instruments may be used in connection with commodity price and interest rate activities, including swaps, futures, forwards and options. All derivative instruments, except those that qualify for the normal purchase/normal sale exception, are recorded on the Balance Sheets at fair value. For activity subject to regulatory accounting, gains and losses on derivative contracts are reflected as regulatory assets or regulatory liabilities and not as other comprehensive income or current period income. As a result, changes in fair value of these derivatives have no immediate earnings impact. See Note 10 for further information.

Unamortized Debt Premium, Discount and Expense

Premiums, discounts and expenses incurred with the issuance of outstanding long-term debt are amortized over the term of the debt issue. The gain or loss on extinguishment associated with refinancing higher-cost debt obligations in the regulated operations is amortized over the remaining life of the original instrument. Amortization expense is recorded as Interest Expense in the Statements of Operations and is reflected as Depreciation and amortization within Net cash provided by operating activities on the Statements of Cash Flows.

Premiums, discounts and expenses are presented as an adjustment to the carrying value of the debt amount and included in Long-Term Debt on the Balance Sheets presented.

Loss Contingencies and Environmental Liabilities

Contingent losses are recorded when it is probable a loss has occurred and can be reasonably estimated. When a range of the probable loss exists and no amount within the range is a better estimate than any other amount, the minimum amount in the range is recorded. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Environmental liabilities are recorded on an undiscounted basis when environmental remediation or other liabilities become probable and can be reasonably estimated. Environmental expenditures related to past operations that do not generate current or future revenues are expensed. Environmental expenditures related to operations that generate current or future revenues are expensed or capitalized, as appropriate. Certain environmental expenditures receive regulatory accounting treatment and are recorded as regulatory assets. See Notes 2 and 3 for further information.

Pension and Other Post-Retirement Benefit Plans

Duke Energy maintains qualified, non-qualified and other post-retirement benefit plans. Eligible employees of Duke Energy Kentucky participate in the respective qualified, non-qualified and other post-retirement benefit plans and Duke Energy Kentucky is allocated its proportionate share of benefit costs. See Note 14 for further information, including significant accounting policies associated with these plans.

Income Taxes

Duke Energy and its subsidiaries file a consolidated federal income tax return and other state and foreign jurisdictional returns. Duke Energy Kentucky has a tax-sharing agreement with Duke Energy, and income taxes recorded represent amounts Duke Energy Kentucky would incur as a separate C-Corporation. Deferred income taxes have been provided for temporary differences between GAAP and tax bases of assets and liabilities because the differences create taxable or tax-deductible amounts for future periods. Investment tax credits associated with regulated operations are deferred and amortized as a reduction of income tax expense over the estimated useful lives of the related properties.

Accumulated deferred income tax is valued using the enacted tax rate expected to apply to taxable income in the periods in which the deferred tax asset or liability is expected to be settled or realized. In the event of a change in tax rates, deferred tax assets and liabilities are remeasured as of the enactment date of the new rate. To the extent that the change in the value of the deferred tax represents an obligation to customers, the impact of the remeasurement is deferred to a regulatory liability. Remaining impacts are recorded in income from continuing operations. If Duke Energy Kentucky's estimate of the tax effect of reversing temporary differences is not reflective of actual outcomes, is modified to reflect new developments or interpretations of the tax law, is revised to incorporate new accounting principles, or changes in the expected timing or manner of the reversal then Duke Energy Kentucky's results of operations could be impacted.

Tax-related interest and penalties are recorded in Interest Expense and Other Income and Expenses, net, in the Statements of Operations. See Note 15 for further information.

Dividend Restrictions

Duke Energy Kentucky is required to pay dividends solely out of retained earnings and to maintain a minimum of 35% equity in its capital structure.

New Accounting Standards

The following new accounting standard was adopted by Duke Energy Kentucky in 2021.

Leases with Variable Lease Payments. In July 2021, the Financial Accounting Standards Board (FASB) issued new accounting guidance requiring lessors to classify a lease with variable lease payments that do not depend on a reference index or rate as an operating lease if both of the following are met: (1) the lease would have to be classified as a sales-type or direct financing lease under prior guidance, and (2) the lessor would have recognized a day-one loss. Duke Energy Kentucky elected to adopt the guidance immediately upon issuance of the new standard and will be applying the new standard prospectively to new lease arrangements meeting the criteria. Duke Energy Kentucky did not have any lease arrangements that this new accounting guidance materially impacted.

The following new accounting standard has been issued but not yet adopted by Duke Energy Kentucky as of December 31, 2021.

Reference Rate Reform. In March 2020, the FASB issued new accounting guidance for reference rate reform. This guidance is elective and provides expedients to facilitate financial reporting for the anticipated transition away from the London Inter-bank Offered Rate (LIBOR) and other interbank reference rates starting in 2021 with all rates expected to be fully phased out in 2023. The optional expedients are effective for modification of existing contracts or new arrangements executed between March 12, 2020, through December 31, 2022.

Duke Energy Kentucky has variable-rate debt and manages interest rate risk by entering into financial contracts including interest rate swaps that are generally indexed to LIBOR. Impacted financial arrangements extending beyond the phase out of the applicable LIBOR rate may require contractual amendment or termination to fully adapt to a post-LIBOR environment. Duke Energy Kentucky is assessing these financial arrangements and is evaluating the use of optional expedients outlined in the new accounting guidance. Alternative index provisions are also being assessed and incorporated into new financial arrangements that extend beyond the phase out of the applicable LIBOR rate. The full outcome of the transition away from LIBOR cannot be determined at this time, but it is not expected to have a material impact on the financial statements.

2. REGULATORY MATTERS

REGULATORY ASSETS AND LIABILITIES

Duke Energy Kentucky records regulatory assets and liabilities that result from the ratemaking process. See Note 1 for further information.

The following table represents the regulatory assets and liabilities on the Balance Sheets.

	December 31,		Earns/Pays	Recovery/Refund
(in thousands)	2021	2020	a Return	Period Ends
Regulatory Assets(a)				
East Bend deferrals	**$ 36,428**	40,199	X	(c)
AROs – coal ash	**32,776**	22,208	X	(c)(g)
Accrued pension and other post-retirement benefits	**31,454**	35,714		(b)
Deferred fuel and purchased gas costs	**19,588**	—		(d)(g)2022
East Bend outage normalization	**8,309**	4,438		(c)
Demand side management/Energy efficiency costs	**4,685**	1,300		(c)(d)
Hedge costs and other deferrals	**4,220**	5,874		(e)
Advanced Metering Infrastructure	**3,498**	3,867		2033
Deferred gas integrity costs	**2,214**	2,468	X	2029
Storm cost deferrals	**2,011**	3,203		(c)

Carbon management research grant	1,267	1,467	2028
Vacation accrual	**1,242**	1,324	2022
Deferred debt expense	**394**	517	2036
Other	**2,111**	4,288	(c)(d)
Total regulatory assets	**150,197**	126,867	
Less: current portion	**35,031**	14,833	
Total noncurrent regulatory assets	**$ 115,166**	$ 112,034	
Regulatory Liabilities[(a)]			
Net regulatory liability related to income taxes	**$ 118,253**	124,395	(c)
Accrued pension and other post-retirement benefits	**6,169**	6,041	(b)
Deferred fuel and purchased gas costs	**3,699**	3,775	(d)2022
Demand side management/Energy efficiency costs	**848**	1,004	(c)(d)
Costs of removal	**747**	7,439	(f)
Other	**155**	3,309	(c)(e)
Total regulatory liabilities	**129,871**	145,963	
Less: current portion	**9,241**	11,389	
Total noncurrent regulatory liabilities	**$ 120,630**	$ 134,574	

(a) Regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 14 for further information.
(c) The expected recovery or refund period varies or has not been determined.
(d) Deferred costs are recovered through a rider mechanism.
(e) Some amounts relate to unrealized gains and losses on derivatives recorded as a regulatory asset or liability, respectively, until the contracts are settled.
(f) Represents funds received from customers to cover future removal of property, plant and equipment from retired or abandoned sites as property is retired. Included in rate base and recovered over the life of associated assets.
(g) Certain amounts are recovered through rates.

RATE RELATED INFORMATION

The KPSC approves rates for retail electric and natural gas services within the Commonwealth of Kentucky. The FERC approves rates for electric sales to wholesale customers served under cost-based rates, as well as sales of transmission service.

Duke Energy Kentucky Natural Gas Base Rate Case

On June 1, 2021, Duke Energy Kentucky filed an application with the KPSC requesting an increase in natural gas base rates of approximately $15 million, an approximate 13% average increase across all customer classes. The drivers for this case are capital invested since Duke Energy Kentucky's last natural gas base rate case in 2018. Duke Energy Kentucky is also seeking implementation of a Governmental Mandate Adjustment mechanism (Rider GMA) in order to recover from or pay to customers the financial impact of governmental directives and mandates, including changes in federal or state tax rates and regulations issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA). On October 8, 2021, Duke Energy Kentucky filed a Stipulation and Recommendation jointly with the Kentucky Attorney General, subject to review and approval by the KPSC, which if approved, would resolve the case. The Stipulation and Recommendation includes a $9 million increase in base revenues, an ROE of 9.375% for natural gas base rates and 9.3% for natural gas riders, a rider for PHMSA-required capital investments with an annual 5% rate increase cap and a four-year natural gas base rate case stay-out. The evidentiary hearing was held on October 18, 2021. On December 28, 2021, the KPSC approved the Stipulation and Recommendation with minor modifications, authorizing a $9 million increase. Rates were effective January 4, 2022.

Midwest Propane Cavern

Duke Energy Kentucky uses propane stored in a cavern to meet peak demand during winter. Duke Energy Ohio is installing a new natural gas pipeline (the Central Corridor Project) in its Ohio service territory to increase system reliability and enable the retirement of older infrastructure. Once the Central Corridor Project is commercially available in March 2022, the propane peaking facility will no longer be necessary and will be retired. On October 7, 2021, and November 4, 2021, Duke Energy Ohio and Duke Energy Kentucky, respectively, filed requests with the Public Utility Commission of Ohio and the KPSC to establish a regulatory asset for their share of expenses incurred related to the retirement of the propane storage cavern and associated propane-air facilities. On January 31, 2022, the KPSC issued an order denying Duke Energy Kentucky's request. As a result of the KPSC order, Duke Energy Kentucky recorded a $0.9 million charge to Impairment of assets and other charges on Duke Energy Kentucky's Statement of Operations and Comprehensive Income in the fourth quarter of 2021. There is approximately $2.6 million and $2.5 million related to the propane caverns in Net property, plant and equipment on Duke Energy Kentucky's Balance Sheets as of December 31, 2021, and December 31, 2020, respectively.

Regional Transmission Organization Realignment

Duke Energy Kentucky transferred control of its transmission assets to effect a Regional Transmission Organization (RTO) realignment from Midcontinent Independent System Operator, Inc. (MISO) to PJM Interconnection, LLC (PJM), effective December 31, 2011.

On December 22, 2010, the KPSC approved Duke Energy Kentucky's request to effect the RTO realignment, subject to a commitment not to seek double-recovery in a future rate case of the transmission expansion fees that may be charged by MISO and PJM in the same period or overlapping periods. Duke Energy Kentucky is currently recovering PJM transmission expansion fees through current base rates.

Upon its exit from MISO on December 31, 2011, Duke Energy Kentucky recorded a liability and expense for its exit obligation and share of MISO Transmission Expansion Planning costs, excluding Multi Value Projects. This liability was recorded within Other in Current Liabilities and Other in Noncurrent Liabilities on the Balance Sheets.

The following table provides a reconciliation of the beginning and ending balance of recorded obligations related to the withdrawal from MISO.

(in thousands)	December 31, 2020	Provision / Adjustments	Cash Reductions	December 31, 2021
MISO withdrawal liability	$ 13,532	**$ 268**	**$ (823)**	**$ 12,977**

3. COMMITMENTS AND CONTINGENCIES

GENERAL INSURANCE

Duke Energy Kentucky has insurance and/or reinsurance coverage either directly or through indemnification from Duke Energy's captive insurance company, Bison Insurance Company Limited, and its affiliates, consistent with companies engaged in similar commercial operations with similar type properties. Duke Energy Kentucky's coverage includes (i) commercial general liability coverage for liabilities arising to third parties for bodily injury and property damage; (ii) workers' compensation; (iii) automobile liability coverage; and (iv) property coverage for all real and personal property damage. Real and personal property damage coverage excludes electric transmission and distribution lines, but includes damages arising from boiler and machinery breakdowns, earthquakes, flood damage and extra expense, but not outage or replacement power coverage. All coverage is subject to certain deductibles or retentions, sublimits, exclusions, terms and conditions common for companies with similar types of operations. Duke Energy Kentucky self-insures its electric transmission and distribution lines against loss due to storm damage and other natural disasters.

The cost of Duke Energy Kentucky's coverage can fluctuate year to year reflecting claims history and conditions of the insurance and reinsurance markets.

In the event of a loss, terms and amounts of insurance and reinsurance available might not be adequate to cover claims and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered by other sources, could have a material effect on Duke Energy Kentucky's results of operations, cash flows or financial position. Duke Energy Kentucky is responsible to the extent losses may be excluded or exceed limits of the coverage available.

ENVIRONMENTAL

Duke Energy Kentucky is subject to federal, state and local regulations regarding air and water quality, hazardous and solid waste disposal, coal ash and other environmental matters. These regulations can be changed from time to time, imposing new obligations on Duke Energy Kentucky.

Remediation Activities

In addition to the AROs discussed in Note 6, Duke Energy Kentucky is responsible for environmental remediation at various sites. These include certain properties that are part of ongoing operations and sites formerly owned or used by Duke Energy Kentucky. These sites are in various stages of investigation, remediation and monitoring. Managed in conjunction with relevant federal, state and local agencies, remediation activities vary based upon site condition and location, remediation requirements, complexity and sharing of responsibility. If remediation activities involve joint and several liability provisions, strict liability, or cost recovery or contribution actions, Duke Energy Kentucky could potentially be held responsible for environmental impacts caused by other potentially responsible parties, and may also benefit from insurance policies or contractual indemnities that cover some or all cleanup costs. Liabilities are recorded when losses become probable and are reasonably estimable. The total costs that may be incurred cannot be estimated because the extent of environmental impact, allocation among potentially responsible parties, remediation alternatives and/or regulatory decisions have not yet been determined. Additional costs associated with remediation activities are likely to be incurred in the future and could be significant. Costs are typically expensed as Operation, maintenance and other on the Statements of Operations unless regulatory recovery of the costs is deemed probable.

Duke Energy Kentucky has accrued approximately $668 thousand of probable and estimable costs related to its various environmental sites in Other within Other Noncurrent Liabilities on the Balance Sheets as of December 31, 2021, and 2020. Additional losses in excess of recorded reserves are expected to be immaterial for the stages of investigation, remediation and monitoring for the environmental sites that have been evaluated. The maximum amount of the range for all stages of Duke Energy Kentucky's environmental sites cannot be determined at this time.

LITIGATION

Duke Energy Kentucky is involved in other legal, tax and regulatory proceedings arising in the ordinary course of business, some of which involve significant amounts. Duke Energy Kentucky believes the final disposition of these proceedings will not have a material effect on its results of operations, cash flows or financial position. Duke Energy Kentucky expenses legal costs related to the defense of loss contingencies as incurred.

OTHER COMMITMENTS AND CONTINGENCIES

General

As part of its normal business, Duke Energy Kentucky is party to various financial guarantees, performance guarantees and other contractual commitments to extend guarantees of credit and other assistance to various third parties. These guarantees involve elements of performance and credit risk, which are not included on the Balance Sheets. The possibility of Duke Energy Kentucky having to honor its contingencies is largely dependent upon future operations of various third parties or the occurrence of certain future events.

operations of various third parties or the occurrence of certain future events.

Purchase Obligations

Pipeline and Storage Capacity Contracts

Duke Energy Kentucky enters into pipeline and storage capacity contracts that commit future cash flows to acquire services needed in its business. Costs arising from capacity commitments are recovered via the Gas Cost Adjustment Clause in Kentucky. The time period for fixed payments under these pipeline and storage capacity contracts is up to five years.

Certain storage and pipeline capacity contracts require the payment of demand charges that are based on rates approved by the FERC in order to maintain rights to access the natural gas storage or pipeline capacity on a firm basis during the contract term. The demand charges that are incurred in each period are recognized in the Statements of Operations as part of natural gas purchases and are included in Cost of natural gas.

The following table presents future unconditional purchase obligations under these contracts.

(in thousands)	December 31, 2021
2022	$ 9,314
2023	8,347
2024	8,185
2025	2,566
2026	394
Thereafter	—
Total	$ 28,806

4. LEASES

As part of its operations, Duke Energy Kentucky leases space on communication towers, meters and office space under various terms and expiration dates. Certain Duke Energy Kentucky lease agreements include options for renewal and early termination. The intent to renew a lease varies depending on the lease type and asset. Renewal options that are reasonably certain to be exercised are included in the lease measurements. The decision to terminate a lease early is dependent on various economic factors. No termination options have been included in any of the lease measurements.

Duke Energy Kentucky has certain lease agreements, which include variable lease payments that are based on the usage of an asset. These variable lease payments are not included in the measurement of the ROU assets or operating lease liabilities on the Balance Sheets.

The following table presents the components of lease expense and are included in Operations, maintenance and other on the Statements of Operations.

	Years Ended December 31,	
(in thousands)	2021	2020
Operating lease expense	$ 1,801	$ 1,846
Short-term lease expense	1	—
Variable lease expense	51	66
Total lease expense	$ 1,853	$ 1,912

The following table presents operating lease maturities and a reconciliation of the undiscounted cash flows to operating lease liabilities.

(in thousands)	December 31, 2021
2022	$ 688
2023	700
2024	712
2025	725
2026	739
Thereafter	8,627
Total operating lease payments	12,191
Less: present value discount	(3,495)
Total operating lease liabilities[(a)]	$ 8,696

(a) Certain operating lease payments include renewal options that are reasonably certain to be exercised.

The following tables contain additional information related to leases.

		December 31,	
(in thousands)	Classification	2021	2020
Assets			
Operating	Operating lease ROU assets, net	$ 8,407	$ 8,786
Total lease assets		$ 8,407	$ 8,786
Liabilities			
Current			
Operating	Other current liabilities	$ 318	$ 293
Noncurrent			
Operating	Operating lease liabilities	8,379	8,696
Total lease liabilities		$ 8,697	$ 8,989

	Years ended December 31,	
(in thousands)	2021	2020
Cash paid for amounts included in the measurement of lease liabilities[(a)]		
Operating cash flows from operating leases	$ 676	$ 665

(a) No amounts were classified as investing cash flows from operating leases for the years ended December 31, 2021, and 2020.

	December 31,	
	2021	2020
Weighted-average remaining lease term (years)		
Operating leases	16	17
Weighted-average discount rate[(a)]		
Operating leases	4.4 %	4.4 %

(a) The discount rate is calculated using the rate implicit in a lease if it is readily determinable. Generally, the rate used by the lessor is not provided to Duke Energy Kentucky and in these cases the incremental borrowing rate is used. Duke Energy Kentucky will typically use its fully collateralized incremental borrowing rate as of the commencement date to calculate and record the lease. The incremental borrowing rate is influenced by the lessee's

(a) The discount rate is calculated using the rate implicit in a lease if it is readily determinable. Generally, the rate used by the lessor is not provided to Duke Energy Kentucky and in these cases the incremental borrowing rate is used. Duke Energy Kentucky will typically use its fully collateralized incremental borrowing rate as of the commencement date to calculate and record the lease. The incremental borrowing rate is influenced by the lessee's credit rating and lease term and as such may differ for individual leases, embedded leases or portfolios of leased assets.

5. DEBT AND CREDIT FACILITIES

SUMMARY OF DEBT AND RELATED TERMS

The following table summarizes outstanding debt.

			December 31,	
(in thousands)	Weighted Average Interest Rate	Year Due	2021	2020
Unsecured debt	3.77 %	2023 - 2057	$ 680,000	$ 630,000
Tax-exempt bonds[(a)(b)]	0.12 %	2027	26,720	76,720
Money pool borrowings[(b)(c)]	0.36 %	2026	127,596	100,472
Unamortized debt discount and premium, net			(174)	(186)
Unamortized debt issuance costs			(2,325)	(2,738)
Total debt	3.13 %		$ 831,817	$ 804,268
Short-term money pool borrowings			(102,596)	(75,472)
Current maturities of long-term debt			—	(50,000)
Total long-term debt			$ 729,221	$ 678,796

(a) Includes $27 million that is secured by a bilateral letter of credit agreement at December 31, 2021, and 2020.
(b) Floating-rate debt. At December 31, 2020, the weighted average interest rate was 0.75% and 0.41% for tax-exempt bonds and money pool borrowings, respectively.
(c) Includes $25 million classified as Long-Term Debt Payable to Affiliated Companies on the Balance Sheets at December 31, 2021, and 2020.

MATURITIES AND CALL OPTIONS

The following table shows the annual maturities of long-term debt for the next five years and thereafter. Amounts presented exclude short-term notes payable.

(in thousands)	December 31, 2021
2022	$ —
2023	75,000
2024	—
2025	95,000
2026	70,000
Thereafter	491,720
Total long-term debt, including current maturities	$ 731,720

Duke Energy Kentucky has the ability under certain debt facilities to call and repay the obligation prior to its scheduled maturity. Therefore, the actual timing of future cash repayments could be materially different than as presented above.

SHORT-TERM OBLIGATIONS CLASSIFIED AS LONG-TERM DEBT

Certain tax-exempt bonds that may be put to Duke Energy Kentucky at the option of the holder and money pool borrowings, which are short-term obligations by nature, are classified as long-term due to Duke Energy Kentucky's intent and ability to utilize such borrowings as long-term financing. As Duke Energy's Master Credit Facility and Duke Energy Kentucky's other bilateral letter of credit agreements have non-cancelable terms in excess of one year as of the balance sheet date, Duke Energy Kentucky has the ability to refinance these short-term obligations on a long-term basis. See "Available Credit Facilities" below for additional information.

At December 31, 2021, and 2020, $27 million of tax-exempt bonds and $25 million of money pool borrowings were classified as Long-Term Debt and Long-Term Debt Payable to Affiliated Companies, respectively, on the Balance Sheets.

SUMMARY OF SIGNIFICANT DEBT ISSUANCES

In 2020, Duke Energy Kentucky issued $70 million of unsecured debt, of which $35 million carry a fixed interest rate of 2.65% and mature September 2030, and $35 million carry a fixed interest rate of 3.66% and mature September 2050. The proceeds were used to pay down short-term debt and for general corporate purposes.

AVAILABLE CREDIT FACILITIES

Master Credit Facility

In March 2021, Duke Energy amended its existing $8 billion Master Credit Facility to extend the termination date to March 2026. Duke Energy Kentucky has borrowing capacity under the Master Credit Facility up to a specified sublimit. Duke Energy has the unilateral ability at any time to increase or decrease Duke Energy Kentucky's borrowing sublimit, subject to a maximum sublimit. The amount available to Duke Energy Kentucky under the Master Credit Facility may be reduced to backstop issuances of commercial paper, certain letters of credit and variable-rate demand tax-exempt bonds that may be put to Duke Energy Kentucky at the option of the holder. At December 31, 2021, Duke Energy Kentucky had a borrowing sublimit of $175 million and available capacity of $56 million under the Master Credit Facility.

Duke Energy Kentucky and Duke Energy Indiana, LLC, a subsidiary of Duke Energy, collectively have a $156 million bilateral letter of credit agreement. In February 2018, the bilateral letter of credit agreement was amended to extend the termination date from February 2019 to February 2023. Duke Energy Kentucky may request the issuance of letters of credit up to $27 million on its behalf to support various series of tax-exempt bonds. This credit facility may not be used for any purpose other than to support the tax-exempt bonds.

Term Loan Facility

In October 2021, Duke Energy Kentucky entered into a two-year term loan facility with commitments totaling $50 million. Borrowings under the facility will be used to pay down short-term debt and for general corporate purposes. The term loan was fully drawn at the time of closing in October. The balance is classified as Long-Term Debt on Duke Energy Kentucky's Balance Sheet.

OTHER DEBT MATTERS

Money Pool

Duke Energy Kentucky receives support for its short-term borrowing needs through participation with Duke Energy and certain of its subsidiaries in a money pool arrangement. Under this arrangement, those companies with short-term funds may provide short-term loans to affiliates participating under this arrangement. The money pool is structured such that Duke Energy Kentucky separately manages its cash needs and working capital requirements. Accordingly, there is no net settlement of receivables and payables between money pool participants. Duke Energy may loan funds to its participating subsidiaries, but may not borrow funds through the money pool.

Money pool receivable balances are reflected within Notes receivable from affiliated companies on the Balance Sheets. Money pool payable balances are reflected within either Notes payable to affiliated companies or Long-Term Debt Payable to Affiliated Companies on the Balance Sheets.

Restrictive Debt Covenants

Duke Energy Kentucky's debt and credit agreements contain various financial and other covenants. Duke Energy's Master Credit Facility contains a covenant requiring the debt-to-total capitalization ratio not to exceed 65% for each borrower. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of December 31, 2021, Duke Energy Kentucky was in compliance with all covenants related to its debt agreements. In addition, some credit agreements may allow for acceleration of payments or termination of the agreements due to nonpayment, or acceleration of other significant indebtedness of the borrower or some of its subsidiaries. None of the debt or credit agreements contain material adverse change clauses.

6. ASSET RETIREMENT OBLIGATIONS

Duke Energy Kentucky records an ARO when it has a legal obligation to incur retirement costs associated with the retirement of a long-lived asset and the obligation can be reasonably estimated. Certain assets have an indeterminate life, and thus the fair value of the retirement obligation is not reasonably estimable. A liability for these AROs will be recorded when a fair value is determinable.

Duke Energy Kentucky's regulated electric and regulated natural gas operations accrue costs of removal for property that does not have an associated legal retirement obligation based on regulatory orders from the KPSC. These costs of removal are recorded as a regulatory liability in accordance with regulatory accounting treatment. See Note 2 for the estimated cost of removal for assets without an associated legal retirement obligation, which are included in Regulatory liabilities on the Balance Sheets as of December 31, 2021, and 2020.

Duke Energy Kentucky is subject to state and federal regulations covering the closure of coal ash impoundments, including the EPA Coal Combustion Residuals (CCR) Rule. AROs recorded on the Balance Sheets include the legal obligation for the disposal of CCR, which is based upon estimated closure costs for impacted ash impoundments. The amount recorded represents the discounted cash flows for estimated closure costs based upon specific closure plans. Actual costs to be incurred will be dependent upon factors that vary from site to site. The most significant factors are the method and time frame of closure at the individual sites. Closure methods considered include removing the water from ash basins, consolidating material as necessary and capping the ash with a synthetic barrier, excavating and relocating the ash to a lined structural fill or lined landfill or recycling the ash for concrete or some other beneficial use. The ultimate method and timetable for closure will be in compliance with standards set by federal and state regulations and other agreements. The ARO amount will be adjusted as additional information is gained through the closure and post-closure process, including acceptance and approval of compliance approaches, which may change management assumptions, and may result in a material change to the balance. Asset retirement costs associated with coal ash AROs at the East Bend Station are included within Property, Plant and Equipment on the Balance Sheets.

In addition to the coal ash AROs, Duke Energy Kentucky also has legal obligations related to the retirement of gas mains and asbestos remediation.

The following table presents the changes in the liability associated with AROs.

	Years Ended December 31,	
(in thousands)	2021	2020
Balance at beginning of period	$ 76,112	$ 49,780
Accretion expense[(a)]	2,518	1,898
Liabilities settled	(2,761)	(1,949)
Revisions to estimates of cash flows[(b)]	17,413	26,383
Balance at end of period	$ 93,282	$ 76,112

(a) All accretion expense for the years ended December 31, 2021, and 2020, relates to Duke Energy Kentucky's regulated operations and has been deferred in accordance with regulatory accounting treatment.
(b) Amounts primarily relate to changes in maintenance and landfill closure cost estimates for ash impoundments.

7. PROPERTY, PLANT AND EQUIPMENT

The following table summarizes property, plant and equipment.

	Average Remaining Useful Life	December 31,	
(in thousands)	(Years)	2021	2020
Land		$ 41,365	$ 36,925
Plant			
Electric generation, distribution and transmission	47	2,073,113	2,015,291
Natural gas transmission and distribution	49	757,878	701,175
Other buildings and improvements	61	14,197	13,018
Equipment	13	36,869	38,269
Construction in process		97,535	71,664
Other	13	60,455	68,031
Total property, plant and equipment		3,081,412	2,944,373
Accumulated depreciation and amortization		(1,063,561)	(1,030,627)
Facilities to be retired, net		1,769	—
Net property, plant and equipment[(a)]		$ 2,019,620	$ 1,913,746

(a) The debt component of AFUDC totaled $450 thousand and $0 at December 31, 2021, and 2020, respectively.

8. OTHER INCOME AND EXPENSES, NET

The components of Other Income and Expenses, net on the Statements of Operations are as follows.

	Years Ended December 31,	
(in thousands)	2021	2020
Income/(Expense):		
Interest income	$ 982	$ 965
AFUDC equity	1,260	(124)
Other	2,612	1,951
Other Income and Expenses, net	$ 4,854	$ 2,792

9. RELATED PARTY TRANSACTIONS

Duke Energy Kentucky engages in related party transactions, which are generally performed at cost and in accordance with KPSC and FERC regulations. Refer to the Balance Sheets for balances due to or from related parties. Material amounts related to transactions with related parties included in the Statements of Operations are presented in the following table.

	Years Ended December 31,	
(in thousands)	2021	2020
Corporate governance and shared service expenses[(a)]	$ 83,976	$ 86,038

(a) Duke Energy Kentucky is charged its proportionate share of costs, primarily related to human resources, employee benefits, information technology, legal and accounting fees, as well as other third-party costs, from a consolidated affiliate of Duke Energy. These amounts are recorded in Operation, maintenance and other within Operating Expenses on the Statements of Operations.

In addition to the amounts presented above, Duke Energy Kentucky has other affiliate transactions, including certain indemnification coverages through Duke Energy's wholly owned captive insurance subsidiary, rental of office space, participation in a money pool arrangement with Duke Energy and certain of its subsidiaries, other operational transactions and its proportionate share of certain charged expenses. See Note 5 for more information regarding the money pool.

Certain trade receivables have been sold by Duke Energy Kentucky to CRC, an unconsolidated entity formed by a subsidiary of Duke Energy. The proceeds obtained from the sales of receivables are largely cash but do include a subordinated note from CRC for a portion of the purchase price. See Note 12 for further information related to the sales of these receivables.

Intercompany Income Taxes

Duke Energy and its subsidiaries file a consolidated federal income tax return and other state and jurisdictional returns. Duke Energy Kentucky has a tax sharing agreement with Duke Energy for the allocation of consolidated tax liabilities and benefits. Income taxes recorded represent amounts Duke Energy Kentucky would incur as a separate C-Corporation. Duke Energy Kentucky had an intercompany tax receivable balance of $9 million at December 31, 2021, and an intercompany tax payable balance of $2 million at December 31, 2020.

10. DERIVATIVES AND HEDGING

COMMODITY PRICE RISK

Duke Energy Kentucky has limited exposure to market price changes of fuel and emission allowance costs incurred for its retail customers due to the use of cost tracking and recovery mechanisms. Duke Energy Kentucky does have exposure to the impact of market fluctuations in the prices of electricity, fuel and emission allowances associated with its generation output not utilized to serve retail operations or committed load (off-system, wholesale power sales). Duke Energy Kentucky's outstanding commodity derivatives, FTRs, had a notional volume of 1,681 gigawatt-hours and 2,559 gigawatt-hours at December 31, 2021, and 2020, respectively.

See Note 11 for additional information on the fair value of commodity derivatives.

INTEREST RATE RISK

Duke Energy Kentucky is exposed to changes in interest rates as a result of its issuance or anticipated issuance of variable-rate and fixed-rate debt. Interest rate risk is managed by limiting variable-rate exposure to a percentage of total debt and by monitoring changes in interest rates. To manage risk associated with changes in interest rates, Duke Energy Kentucky may enter into financial contracts including interest rate swaps and U.S. Treasury lock agreements. The notional amount of interest rate swaps outstanding was $26.7 million at December 31, 2021, and 2020. Financial contracts entered into by Duke Energy Kentucky are not designated as a hedge because they are accounted for under regulatory accounting. With regulatory accounting, the mark-to-market gains or losses are deferred as regulatory liabilities or assets, respectively. Regulatory assets and regulatory liabilities are amortized consistent with the treatment of related costs in the ratemaking process. The accrual of interest on swaps is recorded as Interest Expense on the Statements of Operations.

See Note 11 for additional information on the fair value of interest rate derivatives.

CREDIT RISK

Duke Energy Kentucky analyzes the financial condition of counterparties prior to entering into agreements and establishes credit limits and monitors the appropriateness of those limits on an ongoing basis. Credit limits and collateral requirements for retail electric customers are established by the KPSC.

Duke Energy Kentucky's industry has historically operated under negotiated credit lines for physical delivery contracts. Duke Energy Kentucky may use master collateral agreements to mitigate certain credit exposures. The collateral agreements require certain counterparties to post cash or letters of credit for the amount of exposure in excess of an established threshold. The threshold amount represents an unsecured credit limit determined in accordance with the corporate credit policy. Collateral agreements also provide that the inability to post collateral is sufficient cause to terminate contracts and liquidate all positions.

Duke Energy Kentucky also obtains cash or letters of credit from customers to provide credit support outside of collateral agreements, where appropriate, based on its financial analysis of the customer and the regulatory or contractual terms and conditions applicable to each transaction.

11. FAIR VALUE MEASUREMENTS

Fair value is the exchange price to sell an asset or transfer a liability in an orderly transaction between market participants at the measurement date. The fair value definition focuses on an exit price versus the acquisition cost. Fair value measurements use market data or assumptions market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs may be readily observable, corroborated by market data or generally unobservable. Valuation techniques maximize the use of observable inputs and minimize use of unobservable inputs. A midmarket pricing convention (the midpoint price between bid and ask prices) is permitted for use as a practical expedient. Fair value measurements are classified in three levels based on the fair value hierarchy as defined by GAAP.

Fair value accounting guidance permits entities to elect to measure certain financial instruments that are not required to be accounted for at fair value, such as equity method investments or the company's own debt, at fair value. Duke Energy Kentucky has not elected to record any of these items at fair value.

Commodity derivatives

If forward price curves are not observable for the full term of the contract and the unobservable period had more than an insignificant impact on the valuation, the commodity derivative is classified as Level 3. The valuation technique and unobservable input for an FTR is regional transmission organization auction pricing and FTR price - per megawatt-hour, respectively.

Interest rate derivatives

All over-the-counter interest rate contract derivatives are valued using financial models that utilize observable inputs for similar instruments and are classified as Level 2. Inputs include forward interest rate curves, notional amounts, interest rates and credit quality of the counterparties.

QUANTITATIVE DISCLOSURES

The following tables provide recorded balances for assets and liabilities measured at fair value on a recurring basis on the Balance Sheets. Derivative amounts in the table below exclude cash collateral.

	December 31, 2021		
(in thousands)	**Total Fair Value**	**Level 2**	**Level 3**
Derivative assets[(a)]	**$ 1,636**	**$ —**	**$ 1,636**
Derivative liabilities[(b)]	**(4,645)**	**(4,645)**	**—**
Net (liabilities) assets	**$ (3,009)**	**$ (4,645)**	**$ 1,636**

	December 31, 2020		
(in thousands)	**Total Fair Value**	**Level 2**	**Level 3**
Derivative assets[(a)]	$ 1,380	$ —	$ 1,380
Derivative liabilities[(b)]	(6,299)	(6,299)	—
Net (liabilities) assets	$ (4,919)	$ (6,299)	$ 1,380

(a) Included in Other within Current Assets and Other within Other Noncurrent Assets on the Balance Sheets. The amounts classified as Level 3 relate to FTRs.
(b) Included in Other within Current Liabilities and Other within Other Noncurrent Liabilities on the Balance Sheets. The amounts classified as Level 2 relate to interest rate swaps.

The following table provides a reconciliation of beginning and ending balances of assets and liabilities measured at fair value on a recurring basis where the determination of fair value includes significant unobservable inputs (Level 3).

	Derivatives (net) Years Ended December 31,	
(in thousands)	**2021**	**2020**
Balance at beginning of period	**$ 1,380**	$ 3,507
Purchases, sales, issuances and settlements:		
Purchases	**3,332**	3,601
Settlements	**(3,419)**	(5,750)
Total gains included on the Balance Sheets as regulatory assets or liabilities	**343**	22
Balance at end of period	**$ 1,636**	$ 1,380

OTHER FAIR VALUE DISCLOSURES

The fair value of long-term debt, including current maturities, is summarized in the following table. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates determined are not necessarily indicative of the amounts Duke Energy Kentucky could have settled in current markets. The fair value of long-term debt is determined using Level 2 measurements.

	December 31, 2021		December 31, 2020	
(in thousands)	**Book value**	**Fair value**	**Book value**	**Fair value**
Long-Term debt, including current maturities	**$ 729,221**	**$ 793,431**	$ 728,796	$ 810,738

At December 31, 2021, and 2020, the fair value of cash and cash equivalents, accounts and notes receivable, and accounts and notes payable are not materially different from their carrying amounts because of the short-term nature of these instruments and/or because the stated rates approximate market rates.

12. VARIABLE INTEREST ENTITIES

A variable interest entity (VIE) is an entity that is evaluated for consolidation using more than a simple analysis of voting control. The analysis to determine whether an entity is a VIE considers contracts with an entity, credit support for an entity, the adequacy of the equity investment of an entity and the relationship of voting power to the amount of equity invested in an entity. This analysis is performed either upon the creation of a legal entity or upon the occurrence of an event requiring reevaluation, such as a significant change in an entity's assets or activities. A qualitative analysis of control determines the party that consolidates a VIE. This assessment is based on (i) what party has the power to direct the activities of the VIE that most significantly impact its economic performance and (ii) what party has rights to receive benefits or is obligated to absorb losses that could potentially be significant to the VIE. The analysis of the party that consolidates a VIE is a continual reassessment.

Cinergy Receivables Company

CRC is a bankruptcy remote, special purpose entity that is an affiliate of Duke Energy Kentucky. As discussed below, Duke Energy Kentucky does not consolidate CRC as it is not the primary beneficiary. On a revolving basis, CRC buys certain accounts receivable arising from the sale of electricity, natural gas and related services from Duke Energy Kentucky. CRC borrows amounts under a credit facility to buy the receivables from Duke Energy Kentucky. Borrowing availability from the credit facility is limited to the amount of qualified receivables sold to CRC which generally exclude receivables past due more than a predetermined number of days and reserves for expected past due balances. The sole source of funds to satisfy the related debt obligation is cash collections from the receivables. Amounts borrowed under the credit facility are reflected on the Balance Sheets as Long-Term Debt.

The proceeds Duke Energy Kentucky receives from the sale of receivables to CRC are approximately 75% cash and 25% in the form of a subordinated note from CRC. The subordinated note is a retained interest in the receivables sold. Duke Energy Kentucky had receivables of $22.4 million and $21.0 million from CRC at December 31, 2021, and 2020, respectively. These balances are included in Receivables from affiliated companies on the Balance Sheets and reflect Duke Energy Kentucky's retained interest in receivables sold to CRC.

CRC is considered a VIE because (i) equity capitalization is insufficient to support its operations, (ii) power to direct the activities that most significantly impact the economic performance of the entity is not held by the equity holder and (iii) deficiencies in net worth of CRC are funded by Duke Energy. The most significant activities that impact the economic performance of CRC are decisions made to manage delinquent receivables. Duke Energy is considered the primary beneficiary and consolidates CRC as it makes these decisions. Duke Energy Kentucky does not consolidate CRC.

The subordinated note held by Duke Energy Kentucky is stated at fair value. Carrying values of retained interests are determined by allocating carrying value of the receivables between assets sold and interests retained based on relative fair value. The allocated basis of the subordinated note is not materially different than the face value because (i) the receivables generally turnover in less than two months, (ii) credit losses are reasonably predictable due to the broad customer base and lack of significant concentration and (iii) the equity in CRC is subordinate to all retained interests and thus would absorb losses first. The hypothetical effect on fair value of the retained interests assuming both a 10% and a 20% unfavorable variation in credit losses or discount rates is not material due to the short turnover of receivables and historically low credit loss history. Interest accrues to Duke Energy Kentucky on the retained interests using the acceptable yield method. This method generally approximates the stated rate on the note since the allocated basis and the face value are nearly equivalent. An impairment charge is recorded against the carrying value of both retained interests and purchased beneficial interest whenever it is determined that an other-than-temporary impairment has occurred. Duke Energy Kentucky's maximum exposure to loss does not exceed the carrying value.

Key assumptions used in estimating fair value are detailed in the following table.

	2021	2020
Anticipated credit loss ratio	0.4 %	0.4 %
Discount rate	1.1 %	1.6 %
Receivables turnover rate	11.4 %	11.3 %

The following table presents gross and net receivables sold.

	December 31,	
(in thousands)	2021	2020
Receivables sold	$ 76,127	$ 66,298
Less: Retained interests	22,397	21,031
Net receivables sold	$ 53,730	$ 45,267

The following table shows sales and cash flows related to receivables sold.

	Years Ended December 31,	
(in thousands)	2021	2020
Sales		
Receivables sold	$ 516,369	$ 456,902
Loss recognized on sale	1,657	1,427
Cash flows		
Cash proceeds from receivables sold	$ 513,346	$ 450,487
Collection fees received	258	228
Return received on retained interests	976	937

Cash flows from sales of receivables are reflected within Cash Flows from Operating Activities and Cash Flows from Investing Activities on the Statements of Cash Flows.

Collection fees received in connection with the servicing of transferred accounts receivable are included in Operation, maintenance and other on the Statements of Operations. The loss recognized on sales of receivables is calculated monthly by multiplying receivables sold during the month by the required discount. The required discount is derived monthly utilizing a three-year weighted average formula that considers charge-off history, late charge history and turnover history on the sold receivables, as well as a component for the time value of money. The discount rate, or component for the time value of money, is the prior month-end London Interbank Offered Rate plus a fixed rate of 1.00%.

13. REVENUE

Duke Energy Kentucky recognizes revenue consistent with amounts billed under tariff offerings or at contractually agreed upon rates based on actual physical delivery of electric or natural gas service, including estimated volumes delivered when billings have not yet occurred. As such, the majority of Duke Energy Kentucky's revenues have fixed pricing based on the contractual terms of the published tariffs, with variability in expected cash flows attributable to the customer's volumetric demand and ultimate quantities of energy or natural gas supplied and used during the billing period. The stand-alone selling price of related sales are designed to support recovery of prudently incurred costs and an appropriate return on invested assets and are primarily governed by published tariff rates or contractual agreements approved by relevant regulatory bodies. Certain excise taxes and franchise fees levied by state or local governments are required to be paid even if not collected from the customer. These taxes are recognized on a gross basis as part of revenues. Duke Energy Kentucky elects to account for all other taxes net of revenues.

Performance obligations are satisfied over time as energy or natural gas is delivered and consumed with billings generally occurring monthly and related payments due within 30 days, depending on regulatory requirements. In no event does the timing between payment and delivery of the goods and services exceed one year. Using this output method for revenue recognition provides a faithful depiction of the transfer of electric and natural gas service as customers obtain control of the commodity and benefit from its use at delivery. Additionally, Duke Energy Kentucky has an enforceable right to consideration for energy or natural gas delivered at any discrete point in time and will recognize revenue at an amount that reflects the consideration to which Duke Energy Kentucky is entitled for the energy or natural gas delivered.

As described above, the majority of Duke Energy Kentucky's tariff revenues are at-will and, as such, related contracts with customers have an expected duration of one year or less and will not have future performance obligations for disclosure.

Duke Energy Kentucky earns substantially all of its revenues through the sale of electricity and natural gas.

Electricity Sales

Electric sales revenues are earned primarily through retail and wholesale electric service through the generation, transmission, distribution and sale of electricity. Duke Energy Kentucky generally provides retail electric service customers with their full electric load requirements and sells wholesale block sales of electricity into the market.

Retail electric service is generally marketed throughout Duke Energy Kentucky's electric service territory through standard service offers. The standard service offers are through tariffs determined by the KPSC. Each tariff, which is assigned to customers based on customer class, has multiple components such as an energy charge, customer charge, demand charge and applicable riders. Duke Energy Kentucky considers each of these components to be aggregated into a single performance obligation for providing electric service. Electricity is considered a single performance obligation satisfied over time consistent with the series guidance and is provided and consumed over the billing period, generally one month. Retail electric service is typically provided to at-will customers who can cancel service at any time, without a substantive penalty. Additionally, Duke Energy Kentucky adheres to applicable regulatory requirements to ensure the collectability of amounts billed and appropriate mitigating procedures are followed when necessary. As such, revenue from contracts with customers is equivalent to the electricity supplied and billed in that period (including unbilled estimates).

Wholesale electric service is provided through block sales of electricity. Revenues for block sales are recognized monthly as energy is delivered and stand-ready service is provided, consistent with invoiced amounts and unbilled estimates.

Natural Gas Sales

Natural gas sales revenues are earned through retail natural gas service through the transportation, distribution and sale of natural gas. Duke Energy Kentucky generally provides natural gas service customers with all natural gas load requirements. Additionally, while natural gas can be stored, substantially all natural gas provided by Duke Energy Kentucky is consumed by customers simultaneously with receipt of delivery.

Retail natural gas service is marketed throughout Duke Energy Kentucky's natural gas service territory using published tariff rates. The tariff rates are established by the KPSC. Each tariff, which is assigned to customers based on customer class, has multiple components, such as a commodity charge, customer or monthly charge and transportation costs. Duke Energy Kentucky considers each of these components to be aggregated into a single performance obligation for providing natural gas service. For contracts where Duke Energy Kentucky provides all of the customer's natural gas needs, the delivery of natural gas is considered a single performance obligation satisfied over time, and revenue is recognized monthly based on billings and unbilled estimates as service is provided and the commodity is consumed over the billing period. Additionally, natural gas service is typically at-will and customers can cancel service at any time, without a substantive penalty. Duke Energy Kentucky also adheres to applicable regulatory requirements to ensure the collectability of amounts billed and receivable and appropriate mitigating procedures are followed when necessary.

Disaggregated Revenues

For electric and natural gas sales, revenue by customer class is most meaningful to Duke Energy Kentucky as each respective customer class collectively represents unique customer expectations of service, generally has different energy and demand requirements and operates under tailored, regulatory approved pricing structures. Additionally, each customer class is impacted differently by weather and a variety of economic factors including the level of population growth, economic investment, employment levels and regulatory activities. As such, analyzing revenues disaggregated by customer class allows Duke Energy Kentucky to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

Disaggregated revenues are presented as follows:

(in thousands)	Years Ended December 31,	
By market or type of customer	2021	2020
Electricity Sales		
Residential	$ 158,494	$ 136,723
General	154,570	139,705
Industrial	59,299	55,875
Wholesale[(a)]	15,523	9,044
Other revenues	10,384	5,956
Total Electricity Sales revenue from contracts with customers	$ 398,270	$ 347,303

Natural Gas Sales

Residential	$ 75,340	$ 65,941
Commercial	32,142	25,570
Industrial	5,249	4,449
Other revenues	2,890	2,814
Total Natural Gas Sales revenue from contracts with customers	$ 115,621	$ 98,774
Total revenue from contracts with customers	$ 513,891	$ 446,077
Other revenue sources[(b)]	$ 6,301	5,689
Total revenues	$ 520,192	$ 451,766

(a) Duke Energy Kentucky nets wholesale electric sales and purchases on an hourly basis. As such, the net position may result in fluctuations between positive and negative net revenues at the end of a reporting period.
(b) Other revenue sources include revenues from derivatives, leases and alternative revenue programs that are not considered revenues from contracts with customers.

As described in Note 1, Duke Energy Kentucky adopted the new guidance for credit losses effective January 1, 2020, using the modified retrospective method of adoption, which does not require restatement of prior year reported results. The following table presents the reserve for credit losses for trade and other receivables based on adoption of the new standard.

(in thousands)	
Balance at December 31, 2019	$ 314
Write-offs	(373)
Credit Loss Expense	383
Balance at December 31, 2020	$ 324
Write-offs	(7)
Credit Loss Expense	(2)
Balance at December 31, 2021	$ 315

Trade and other receivables are evaluated based on an estimate of the risk of loss over the life of the receivable and current and historical conditions using supportable assumptions. Management evaluates the risk of loss for trade and other receivables by comparing the historical write-off amounts to total revenue over a specified period. Historical loss rates are adjusted due to the impact of current conditions, including the impacts of COVID-19, as well as forecasted conditions over a reasonable time period. The calculated write-off rate can be applied to the receivable balance for which an established reserve does not already exist. Management reviews the assumptions and risk of loss periodically for trade and other receivables.

The aging of trade receivables is presented in the table below. Duke Energy Kentucky considers receivables greater than 30 days outstanding past due.

	December 31,	
(in thousands)	2021	2020
Unbilled Receivables[(a)(b)]	$ 326	$ 779
0-30 days	2,346	4,094
30-60 days	177	330
60-90 days	34	59
90+ days	5,069	3,395
Deferred Payment Arrangements[(c)]	21	—
Trade and Other Receivables	$ 7,973	$ 8,657

(a) Unbilled revenues are recognized by applying customer billing rates to the estimated volumes of energy or natural gas delivered but not yet billed and are included in Receivables on the Duke Energy Kentucky Balance Sheets. Unbilled receivables relate to transactions with PJM.
(b) Duke Energy Kentucky sells, on a revolving basis, nearly all of its retail accounts receivable, including receivables for unbilled revenues, to CRC. As discussed further in Note 8, Duke Energy Kentucky accounts for these transfers of receivables as sales. Accordingly, the receivables sold are not reflected on the Balance Sheets. Receivables for unbilled revenues included in the sales of accounts receivable to CRC were $27 million and $23 million at December 31, 2021, and 2020, respectively.
(c) Due to certain customer financial hardships created by the COVID-19 pandemic and resulting stay-at-home orders, Duke Energy Kentucky permitted customers to defer payment of past-due amounts through an installment payment plan over a period of several months.

14. EMPLOYEE BENEFIT PLANS

DEFINED BENEFIT RETIREMENT PLANS

Duke Energy Kentucky participates in qualified and non-qualified defined benefit retirement plans and other post-retirement benefit plans sponsored by Duke Energy. Duke Energy allocates pension and other post-retirement obligations and costs related to these plans to Duke Energy Kentucky. The plans cover most employees using a cash balance formula. Under a cash balance formula, a plan participant accumulates a retirement benefit consisting of pay credits based upon a percentage of current eligible earnings based on age and/or years of service and interest credits. Certain employees are covered under plans that use a final average earnings formula. Under these average earnings formulas, a plan participant accumulates a retirement benefit equal to the sum of percentages of their (i) highest three-year or four-year average earnings, (ii) highest three-year or four-year average earnings in excess of covered compensation per year of participation (maximum of 35 years) and/or (iii) highest three-year average earnings times years of participation in excess of 35 years. Duke Energy also maintains, and Duke Energy Kentucky participates in, non-qualified, non-contributory defined benefit retirement plans which cover certain executives. The qualified and non-qualified non-contributory defined benefit plans are closed to new participants.

Duke Energy uses a December 31 measurement date for its defined benefit retirement plan assets and obligations. Actuarial losses experienced by the defined benefit retirement plans in remeasuring plan assets as of December 31, 2021, were primarily attributable to actual investment performance that was less than expected investment performance. Actuarial gains experienced by the defined benefit retirement plans in remeasuring plan obligations as of December 31, 2021, were primarily attributable to the increase in the discount rate used to measure plan obligations. Actuarial gains experienced by the defined benefit retirement plans in remeasuring plan assets as of December 31, 2020, were attributable to actual investment performance that exceeded expected investment performance. Actuarial losses experienced by the defined benefit retirement plans in remeasuring plan obligations as of December 31, 2020, were primarily attributable to the decrease in the discount rate used to measure plan obligations.

Duke Energy's policy is to fund amounts on an actuarial basis to provide assets sufficient to meet benefit payments to be paid to plan participants. Duke Energy Kentucky did not make any contributions in 2021. Duke Energy Kentucky does not anticipate making any contributions in 2022.

Net periodic benefit costs disclosed in the tables below represent the cost of the respective plan for the periods presented prior to capitalization of amounts reflected as Net property, plant and equipment, on the Balance Sheets. Only the service cost component of net periodic benefit costs is eligible to be capitalized. The remaining non-capitalized portions of net periodic benefit costs are classified as either: (i) service cost, which is recorded in Operations, maintenance and other on the Statements of Operations; or as (ii) components of non-service cost, which is recorded in Other income and expenses, net, on the Statements of Operations. Amounts presented in the tables below represent the amounts of pension and other post-retirement benefit cost allocated by Duke Energy for employees of Duke Energy Kentucky. Additionally, Duke Energy Kentucky is allocated its proportionate share of pension and other post-retirement benefit cost for employees of Duke Energy's shared services affiliate that provides support to Duke Energy Kentucky. These allocated amounts are included in the governance and shared services costs discussed in Note 9.

QUALIFIED PENSION PLANS

Components of Net Periodic Pension Costs

	Years Ended December 31,	
(in thousands)	2021	2020
Service cost	$ 1,212	$ 1,179
Interest cost on projected benefit obligation	3,031	3,761
Expected return on plan assets	(6,207)	(6,539)
Amortization of prior service credit	(95)	(98)
Amortization of actuarial loss	2,118	1,965
Amortization of settlement charges	—	350
Net periodic pension costs	$ 59	$ 618

Amounts Recognized in Regulatory Assets

	December 31,	
(in thousands)	2021	2020
Regulatory assets, net (decrease)	$ (4,069)	$ (127)

Reconciliation of Funded Status to Net Amount Recognized

	Years Ended December 31,	
(in thousands)	2021	2020
Change in Projected Benefit Obligation		
Obligation at prior measurement date	$ 120,132	$ 117,086
Service cost	1,124	1,082
Interest cost	3,031	3,761
Actuarial (gains) losses	(1,741)	6,427
Transfers [a]	(2,943)	—
Benefits paid	(15,153)	(8,224)
Obligation at measurement date	$ 104,450	$ 120,132
Accumulated Benefit Obligation at measurement date	$ 101,920	$ 118,545
Change in Fair Value of Plan Assets		
Plan assets at prior measurement date	$ 106,173	$ 103,267
Actual return on plan assets	5,577	11,130
Benefits paid	(15,153)	(8,224)
Employer contributions	—	—
Transfers [a]	(2,943)	—
Plan assets at measurement date	$ 93,654	$ 106,173
Funded status of plan	$ (10,796)	$ (13,959)

(a) Transfers represents net amounts associated with plan participants that have moved to/from other Duke Energy subsidiaries.

Amounts Recognized in the Balance Sheets

	December 31,	
(in thousands)	2021	2020
Prefunded pension[a]	$ 16,381	$ 12,852
Noncurrent pension liability[b]	27,177	26,811
Net liability recognized	$ (10,796)	$ (13,959)
Regulatory assets	$ 29,961	$ 34,030

(a) Included in Other within Investments and Other Assets on the Balance Sheets.
(b) Included in Accrued pension and other post-retirement benefit costs on the Balance Sheets.

Information for Plans with Accumulated Benefit Obligation in Excess of Plan Assets

	December 31,	
(in thousands)	2021	2020
Projected benefit obligation	$ 41,707	$ 53,559
Accumulated benefit obligation	39,177	51,971
Fair value of plan assets	14,530	26,748

Assumptions Used for Pension Benefits Accounting

	December 31,	
	2021	2020
Benefit Obligations		
Discount rate	2.90 %	2.60 %
Interest crediting rate	4.00 %	4.00 %
Salary increase	3.50 %	3.50 %
Net Periodic Benefit Cost		
Discount rate	2.60 %	3.30 %
Interest crediting rate	4.00 %	4.00 %
Salary increase	3.50 %	3.50 %
Expected long-term rate of return on plan assets	6.50 %	6.85 %

The discount rate used to determine the current year pension obligation and following year's pension expense is based on a bond selection-settlement portfolio approach. This approach develops a discount rate by selecting a portfolio of high quality corporate bonds that generate sufficient cash flow to provide for the projected benefit payments of the plan. The selected bond portfolio is derived from a universe of non-callable corporate bonds rated Aa quality or higher. After the bond portfolio is selected, a single interest rate is determined that equates the present value of the plan's projected benefit payments discounted at this rate with the market value of the bonds selected.

NON-QUALIFIED PENSION PLANS

The accumulated benefit obligation, which equals the projected benefit obligation for non-qualified pension plans, was $77 thousand for Duke Energy Kentucky as of December 31, 2021. Employer contributions, which equal benefits paid for non-qualified pension plans, were not material for the year ended December 31, 2021. Net periodic pension costs for non-qualified pension plans were not material for the years ended December 31, 2021, or 2020.

OTHER POST-RETIREMENT BENEFIT PLANS

Duke Energy provides, and Duke Energy Kentucky participates in, some health care and life insurance benefits for retired employees on a contributory and non-contributory basis. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans. The health care benefits include medical, dental and prescription drug coverage and are subject to certain limitations, such as deductibles and co-payments.

Duke Energy did not make any pre-funding contributions to its other post-retirement benefit plans during the years ended December 31, 2021, and 2020.

Components of Net Periodic Other Post-Retirement Benefit Costs

	Years Ended December 31,	
(in thousands)	2021	2020
Service cost	$ 81	$ 133
Interest cost on projected benefit obligation	112	174
Expected return on plan assets	(67)	(77)
Amortization of prior service credit	(220)	(236)
Amortization of actuarial loss	214	231

Net periodic post-retirement pension costs	**$ 120**	$ 225

Amounts Recognized in Regulatory Assets and Regulatory Liabilities

	December 31,	
(in thousands)	**2021**	**2020**
Regulatory assets, net decrease	**$ (187)**	$ (209)
Regulatory liabilities, net increase	**(128)**	(712)

Reconciliation of Funded Status to Accrued Other Post-Retirement Benefit Costs

	Years Ended December 31,	
(in thousands)	**2021**	**2020**
Change in Projected Benefit Obligation		
Accumulated post-retirement benefit obligation at prior measurement date	**$ 4,619**	$ 5,596
Service cost	**81**	133
Interest cost	**112**	174
Plan participants' contributions	**179**	187
Actuarial gains	**(284)**	(820)
Benefits paid	**(513)**	(651)
Accrued retiree drug subsidy	**—**	—
Accumulated post-retirement benefit obligation at measurement date	**$ 4,194**	$ 4,619
Change in Fair Value of Plan Assets		
Plan assets at prior measurement date	**$ 1,750**	$ 1,562
Actual return on plan assets	**104**	184
Plan participants' contributions	**179**	187
Benefits paid	**(513)**	(651)
Employer contributions	**55**	468
Plan assets at measurement date	**$ 1,575**	$ 1,750
Funded status of plan	**$ (2,619)**	$ (2,869)

Amounts Recognized in the Balance Sheets

	December 31,	
(in thousands)	**2021**	**2020**
Current post-retirement liability[(a)]	**$ 168**	$ 156
Noncurrent post-retirement liability[(b)]	**2,451**	2,713
Total accrued post-retirement liability	**$ 2,619**	$ 2,869
Regulatory assets	**$ 1,447**	$ 1,634
Regulatory liabilities	**$ 6,169**	$ 6,041

(a) Included in Other within Current Liabilities on the Balance Sheets.
(b) Included in Accrued pension and other post-retirement benefit costs on the Balance Sheets.

Assumptions Used for Other Post-Retirement Benefits Accounting

	December 31,	
	2021	**2020**
Benefit Obligations		
Discount rate	**2.90 %**	2.60 %
Net Periodic Benefit Cost		
Discount rate	**2.60 %**	3.30 %
Expected long-term rate of return on plan assets	**6.50 %**	6.85 %

The discount rate used to determine the current year other post-retirement benefits obligation and following year's other post-retirement benefits expense is based on a bond selection-settlement portfolio approach. This approach develops a discount rate by selecting a portfolio of high quality corporate bonds that generate sufficient cash flow to provide for the projected benefit payments of the plan. The selected bond portfolio is derived from a universe of non-callable corporate bonds rated Aa quality or higher. After the bond portfolio is selected, a single interest rate is determined that equates the present value of the plan's projected benefit payments discounted at this rate with the market value of the bonds selected.

Assumed Health Care Cost Trend Rate

	December 31,	
	2021	**2020**
Health care cost trend rate assumed for next year	**6.25 %**	6.25 %
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	**4.75 %**	4.75 %
Year that the rate reaches the ultimate trend rate	**2028**	2028

Expected Benefit Payments

The following table presents Duke Energy's expected benefit payments to participants on behalf of Duke Energy Kentucky in its qualified and other post-retirement benefit plans over the next 10 years. These benefit payments reflect expected future service, as appropriate.

(in thousands)	**Qualified Plans**	**Other Post-Retirement Plans**	**Total**
Years ending December 31,			
2022	$ 7,877	$ 765	$ 8,642
2023	7,812	537	8,349
2024	7,862	424	8,286
2025	7,566	369	7,935
2026	7,468	320	7,788
2027–2031	35,351	1,206	36,557

MASTER RETIREMENT TRUST

The assets for the Duke Energy Kentucky plans discussed above are derived from the Master Retirement Trust (Master Trust) that is held by Duke Energy and, as such, Duke Energy Kentucky is allocated its proportionate share of assets discussed below. Assets for both the qualified pension and other post-retirement benefits are maintained in the Master Trust. Duke Energy also invests other post-retirement assets in Voluntary Employees' Beneficiary Association trusts. The investment objective is to achieve sufficient returns, subject to a prudent level of portfolio risk, for the purpose of promoting the security of plan benefits for participants. As of December 31, 2021, Duke Energy assumes pension and other post-retirement plan assets will generate a long-term rate of return of 6.50%. The expected long-term rate of return was developed using a weighted average calculation of expected returns based primarily on future expected returns across asset classes considering the use of active asset managers, where applicable. The asset allocation targets were set after considering the investment objective and the risk profile. Equity securities are held for their high expected return. Debt securities are primarily held to hedge the qualified pension plan liability. Return seeking debt securities, hedge funds and other global securities are held for diversification. Investments within asset classes are diversified to achieve broad market participation and reduce the impact of individual managers or investments.

Effective January 1, 2022, the target asset allocation for the Duke Energy Retirement Master Trust is 60% liability hedging assets and 40% return-seeking assets. Duke Energy periodically reviews its asset allocation targets, and over time, as the funded status of the benefit plans increase, the level of asset risk relative to plan liabilities may be reduced to better manage Duke Energy's benefit plan liabilities and reduce funded status volatility.

The following table presents target and actual asset allocations for the Master Trust at December 31, 2021, and 2020.

		Actual Allocation at December 31,	
Asset Category	**Target Allocation**	**2021**	**2020**
Global equity securities	27 %	**24 %**	30 %
Global private equity securities	1 %	**1 %**	1 %
Debt securities	62 %	**62 %**	55 %
Return seeking debt securities	4 %	**4 %**	5 %
Hedge funds	2 %	**3 %**	3 %
Real estate and cash	4 %	**6 %**	6 %
Total	100 %	**100 %**	100 %

EMPLOYEE SAVINGS PLAN

Duke Energy Kentucky also participates in employee savings plans sponsored by Duke Energy. Most employees participate in a matching contribution formula where Duke Energy provides a matching contribution generally equal to 100% of employee before-tax and Roth 401(k) contributions and, as applicable, after-tax contributions of up to 6% of eligible pay per period.

For new and rehired non-union and certain unionized employees who are not eligible to participate in Duke Energy's defined benefit plans, an additional employer contribution of 4% of eligible pay per pay period, which is subject to a three-year vesting schedule, is provided to the employee's savings plan account.

Duke Energy Kentucky's expense related to its proportionate share of pretax employer contributions and the additional 4% employer contribution was $1,215 thousand and $1,225 thousand for the years ended December 31, 2021, and 2020, respectively.

15. INCOME TAXES

INCOME TAX EXPENSE

Components of Income Tax Expense

	Years Ended December 31,	
(in thousands)	**2021**	**2020**
Current income taxes		
Federal	**$ (6,954)**	$ 4,226
State	**(2,229)**	816
Total current income taxes	**(9,183)**	5,042
Deferred income taxes		
Federal	**14,419**	3,005
State	**4,892**	1,722
Total deferred income taxes[(a)]	**19,311**	4,727
Investment tax credit amortization	**(58)**	(61)
Total income tax expense included in Statements of Operations	**$ 10,070**	$ 9,708

(a) Total deferred income taxes includes utilization of NOL carryforwards and tax credit carryforwards of $3 million.

Statutory Rate Reconciliation

The following table presents a reconciliation of income tax expense at the U.S. federal statutory tax rate to actual tax expense.

	Years Ended December 31,	
(in thousands)	**2021**	**2020**
Income tax expense, computed at the statutory rate of 21%	**$ 13,328**	$ 12,149
State income tax, net of federal income tax effect	**2,104**	2,007
Amortization of excess deferred income tax	**(4,741)**	(4,213)
Tax Credits	**(313)**	(272)
Other items, net	**(308)**	37
Total income tax expense	**$ 10,070**	$ 9,708
Effective tax rate	**15.9 %**	16.8 %

DEFERRED TAXES

Net Deferred Income Tax Liability Components

	Years Ended December 31,	
(in thousands)	**2021**	**2020**
Deferred credits and other liabilities	**$ —**	$ 213
Lease obligations	**2,141**	2,190
Tax credits and NOL carryforwards	**5,069**	8,135
Pension, post-retirement and other employee benefits	**4,387**	5,414
Regulatory liabilities and deferred credits	**—**	5,228
Investments and other liabilities	**467**	921
Other	**468**	1,713
Total deferred income tax assets	**12,532**	23,814
Accelerated depreciation rates	**(278,714)**	(266,186)
Regulatory assets and deferred credits	**(1,777)**	—
Total deferred income tax liabilities	**(280,491)**	(266,186)

Net deferred income tax liabilities	$ (267,959)	$ (242,372)

The following table presents the expiration of tax credits and NOL carryforwards.

	December 31, 2021			
(in thousands)	Amount	Expiration Year		
General business credits	$ 5,034	2024	—	2041
State NOL carryforwards	35	2037		
Total tax credits and NOL carryforwards	$ 5,069			

UNRECOGNIZED TAX BENEFITS

The following table presents changes to unrecognized tax benefits.

	Years Ended December 31,	
(in thousands)	2021	2020
Unrecognized tax benefits – January 1	$ 434	$ 405
Unrecognized tax benefit increases	40	29
Total changes	40	29
Unrecognized tax benefits – December 31	$ 474	$ 434

The following table includes additional information regarding the unrecognized tax benefits at December 31, 2021. Duke Energy Kentucky does not expect a decrease in unrecognized tax benefits within the next 12 months.

(in thousands)	December 31, 2021
Amount that if recognized, would affect the effective tax rate or regulatory liability[(a)]	$ 474

(a) Duke Energy Kentucky is unable to estimate the specific amounts that would affect the effective tax rate versus the regulatory liability.

OTHER TAX MATTERS

Duke Energy Kentucky recognized no interest income, interest expense or penalties related to income taxes on the Statements of Operations in 2021, or 2020. As of December 31, 2021, and 2020, no amounts were recognized on the Balance Sheets for interest or penalties related to income taxes.

Duke Energy Kentucky is no longer subject to U.S. federal examination for years before 2016. With few exceptions, Duke Energy Kentucky is no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2016.

16. SUBSEQUENT EVENTS

Subsequent events were evaluated through March 11, 2022. For information on subsequent events related to regulatory matters, see Note 2.

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Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization and Depletion

Line No.	Item (a)	Total Company For the Current Quarter/Year (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Common (f)
1	UTILITY PLANT					
2	In Service					
3	Plant in Service (Classified)	2,725,733,300	1,979,969,127	701,052,507		44,711,666
4	Property Under Capital Leases	8,407,255	[a]8,407,255			
5	Plant Purchased or Sold					
6	Completed Construction not Classified	262,180,076	161,292,168	100,742,819		145,089
7	Experimental Plant Unclassified					
8	TOTAL Utility Plant (Total of lines 3 thru 7)	2,996,320,631	2,149,668,550	801,795,326		44,856,755
9	Leased to Others					
10	Held for Future Use	30,101	30,101			
11	Construction Work in Progress	96,259,188	76,095,968	18,084,206		2,079,014
12	Acquisition Adjustments					
13	TOTAL Utility Plant (Total of lines 8 thru 12)	3,092,609,920	2,225,794,619	819,879,532		46,935,769
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	1,073,764,061	840,267,458	203,850,236		29,646,367
15	Net Utility Plant (Total of lines 13 and 14)	2,018,845,859	1,385,527,161	616,029,296		17,289,402
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION					
17	In Service:					
18	Depreciation	1,024,293,348	825,981,502	191,069,135		7,242,711
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights					
20	Amortization of Underground Storage Land and Land Rights					
21	Amortization of Other Utility Plant	49,470,713	14,285,956	12,781,101		22,403,656
22	TOTAL In Service (Total of lines 18 thru 21)	1,073,764,061	840,267,458	203,850,236		29,646,367
23	Leased to Others					
24	Depreciation					
25	Amortization and Depletion					
26	TOTAL Leased to Others (Total of lines 24 and 25)					

27	Held for Future Use					
28	Depreciation					
29	Amortization					
30	TOTAL Held for Future Use (Total of lines 28 and 29)					
31	Abandonment of Leases (Natural Gas)					
32	Amortization of Plant Acquisition Adjustment					
33	TOTAL Accum. Provisions (Should agree with line 14 above)(Total of lines 22, 26, 30, 31, and 32)	1,073,764,061	840,267,458	203,850,236		29,646,367

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: UtilityPlantInServicePropertyUnderCapitalLeases

Property Under Capital Leases includes Net Operating Leases of $8,407,255.

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Gas Plant in Service (Accounts 101, 102, 103, and 106)

1. Report below the original cost of gas plant in service according to the prescribed accounts.
2. In addition to Account 101, Gas Plant in Service (Classified), this page and the next include Account 102, Gas Plant Purchased or Sold, Account 103, Experimental Gas Plant Unclassified, and Account 106, Completed Construction Not Classified-Gas.
3. Include in column (c) and (d), as appropriate corrections of additions and retirements for the current or preceding year.
4. Enclose in parenthesis credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. 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) reversals of tentative distributions of prior year's unclassified retirements. Include in a footnote, the account 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 Account 101 and 106 will avoid serious omissions of respondent's reported amount for plant actually in service at end of year.
6. 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. In showing the clearance of 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 to primary account classifications.
7. 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 requirements of these pages.
8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give date of such filing.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	INTANGIBLE PLANT						
2	301 Organization						
3	302 Franchise and Consents						
4	303 MiscellaneousIntangiblePlant	17,337,789	2,436,748	3,838,885		10,015	15,945,667
5	Total Intangible Plant (Total of lines 2 thru 4)	17,337,789	2,436,748	3,838,885		10,015	15,945,667
6	PRODUCTION PLANT						
7	Natural Gas Production and Gathering Plant						
8	325.1 Producing Lands						
9	325.2 Producing Leaseholds						
10	325.3 Gas Rights						
11	325.4 RIghts-of-Way						
12	325.5 Other Land and Land Rights						
13	326 Gas Well Structures						
14	327 Field Compressor Station Structures						
15	328 Field Measuring and Regulating Station Structures						
16	329 Other Structures						
17	330 Producing Gas Wells-Well Construction						
18	331 Producing Gas Wells-Well Equipment						
19	332 Field Lines						
20	333 Field Compressor Station Equipment						

21	334 Field Measuring and Regulating Station Equipment						
22	335 Drilling and Cleaning Equipment						
23	336 Purification Equipment						
24	337 Other Equipment						
25	338 Unsuccessful Exploration and Development Costs						
26	339 Asset Retirement Costs for Natural Gas Production and Gathering Plant						
27	Total Production and Gathering Plant (Total of lines 8 thru 26)						
28	PRODUCTS EXTRACTION PLANT						
29	340 Land and Land Rights						
30	341 Structures and Improvements						
31	342 Extraction and Refining Equipment						
32	343 Pipe Lines						
33	344 Extracted Products Storage Equipment						
34	345 Compressor Equipment						
35	346 Gas Measuring and Regulating Equipment						
36	347 Other equipment						
37	348 Asset Retirement Costs for Products Extraction Plant						
38	Total Products Extraction Plant (Total of lines 29 thru 37)						
39	Total Natural Gas Production Plant (Total of lines 27 and 38)						
40	Manufactured Gas Production Plant (Submit supplementary information in a footnote)	12,939,759	1,857,786	(27,834)	[a](913,178)		13,912,201
41	Total Production Plant (Total of lines 39 and 40)	12,939,759	1,857,786	(27,834)	(913,178)		13,912,201
42	NATURAL GAS STORAGE AND PROCESSING PLANT						
43	Underground storage plant						
44	350.1 Land						
45	350.2 Rights-of-Way						
46	351 Structures and Improvements						
47	352 Wells						
48	352.1 Storage Leaseholds and Rights						
49	352.2 Reservoirs						
50	352.3 Non-recoverable Natural Gas						
51	353 Lines						
52	354 Compressor Station Equipment						

53	355 Measuring and Regulating Equipment						
54	356 Purification Equipment						
55	357 Other Equipment						
56	358 Asset Retirement Costs for Underground Storage Plant						
57	Total Underground Storage Plant (Total of lines 44 thru 56)						
58	Other Storage Plant						
59	360 Land and Land Rights						
60	361 Structures and Improvements						
61	362 Gas Holders						
62	363 Purification Equipment						
63	363.1 Liquefaction Equipment						
64	363.2 Vaporizing Equipment						
65	363.3 Compressor Equipment						
66	363.4 Measuring and Regulating Equipment						
67	363.5 Other Equipment						
68	363.6 Asset Retirement Costs for Other Storage Plant						
69	Total Other Storage Plant (Total of lines 58 thru 68)						
70	Base Load Liquefied Natural Gas Terminaling and Processing Plant						
71	364.1 Land and Land Rights						
72	364.2 Structures and Improvements						
73	364.3 LNG Processing Terminal Equipment						
74	364.4 LNG Transportation Equipment						
75	364.5 Measuring and Regulating Equipment						
76	364.6 Compressor Station Equipment						
77	364.7 Communications Equipment						
78	364.8 Other Equipment						
79	364.9 Asset Retirement Costs for Base Load Liquefied Natural Gas						
80	Total Base Load Liquified Natural Gas , Terminating and Processing Plant (Total of lines 71 thru 79)						
81	Total Nat'l Gas Storage and Processing Plant (Total of lines 57, 69, and 80)						
82	TRANSMISSION PLAN						
83	365.1 Land and Land Rights						
84	365.2 Rights-of-Way						

85	366 Structures and Improvements						
86	367 Mains						
87	368 Compressor Station Equipment						
88	369 Measuring and Regulating Station Equipment						
89	370 Communication Equipment						
90	371 Other Equipment						
91	372 Asset Retirement Costs for Transmission Plant						
92	Total Transmission Plant (Total of line 81 thru 91)						
93	DISTRIBUTION PLANT						
94	374 Land and Land Rights	7,011,175	2,638,397			(34,000)	9,615,572
95	375 Structures and Improvements	3,056,581	1,526,503	12,954		(275,824)	4,294,306
96	376 Mains	376,357,685	50,961,826	1,333,387		(1,603,383)	424,382,741
97	377 Compressor Station Equipment						
98	378 Measuring and Regulating Station Equipment-General	56,420,553	291,265	166,733		(1,588,427)	54,956,658
99	379 Measuring and Regulating Station Equipment-City Gate		1,614,864				1,614,864
100	380 Services	205,283,702	6,395,876	1,083,418			210,596,160
101	381 Meters	14,212,485	1,674,796				15,887,281
102	382 Meter Installations	14,965,178	1,143,967				16,109,145
103	383 House Regulators	7,290,434	135,743				7,426,177
104	384 House Regulator Installations	6,053,347	34,093				6,087,440
105	385 Industrial Measuring and Regulating Station Equipment	514,768	5,050				519,818
106	386 Other Property on Customers' Premises						
107	387 Other Equipment	83,070					83,070
108	388 Asset Retirement Costs for Distribution Plant	4,139,652	1,874,544	(174,421)			6,188,617
109	Total Distribution Plant (Total of lines 94 thru 108)	695,388,630	68,296,924	2,422,071		(3,501,634)	757,761,849
110	GENERAL PLANT						
111	389 Land and Land Rights						
112	390 Structures and Improvements						
113	391 Office Furniture and Equipment	1,410,274	122,234	18,902			1,513,606
114	392 Transportation Equipment	69,948					69,948
115	393 Stores Equipment						
116	394 Tools, Shop, and Garage Equipment	1,602,643	34,010	36,239			1,600,414
117	395 Laboratory Equipment						

118	396 Power Operated Equipment	168,272					168,272
119	397 Communication Equipment	10,680,536	59,242				10,739,778
120	398 Miscellaneous Equipment	83,591					83,591
121	Subtotal (Total of lines 111 thru 120)	14,015,264	215,486	55,141			14,175,609
122	399 Other Tangible Property						
123	399.1 Asset Retirement Costs for General Plant						
124	Total General Plant (Total of lines 121, 122, and 123)	14,015,264	215,486	55,141			14,175,609
125	Total (Accounts 101 and 106)	739,681,442	72,806,944	6,288,263	(913,178)	(3,491,619)	801,795,326
126	Gas Plant Purchased (See Instruction 8)						
127	(Less) Gas Plant Sold (See Instruction 8)						
128	Experimental gas plant unclassified						
129	Total Gas Plant In Service (Total of lines 125 thru 128)	739,681,442	72,806,944	6,288,263	(913,178)	(3,491,619)	801,795,326

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: ManufacturedGasProductionPlantAdjustments

Adjustment represents impairments recorded on propane cavern assets

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Gas Property and Capacity Leased from Others

1. Report below the information called for concerning gas property and capacity leased from others for gas operations.
2. For all leases in which the average annual lease payment over the initial term of the lease exceeds $500,000, describe in column (c), if applicable: the property or capacity leased. Designate associated companies with an asterisk in column (b).

Line No.	Name of Lessor (a)	* (b)	Description of Lease (c)	Lease Payments for Current Year (d)
1				
2				
3				
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45	Total			

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Gas Property and Capacity Leased to Others

1. For all leases in which the average lease income over the initial term of the lease exceeds $500,000 provide in column (c), a description of each facility or leased capacity that is classified as gas plant in service, and is leased to others for gas operations.
2. In column (d) provide the lease payments received from others.
3. Designate associated companies with an asterisk in column (b).

Line No.	Name of Lessee (a)	* (b)	Description of Lease (c)	Lease Payments for Current Year (d)
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44				
45	Total			

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Gas Plant Held for Future Use (Account 105)

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

Line No.	Description and Location of Property (a)	Date Originally Included in this Account (b)	Date Expected to be Used in Utility Service (c)	Balance at End of Year (d)
1	Other Land and Land Rights < $1M Each (11 Items)			30,101
45	Total			30,101

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Construction Work in Progress-Gas (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Gas (Account 107) (b)	Estimated Additional Cost of Project (c)
1	DISTRIBUTION PLANT		
2	LINE AM00B ILI RETROFIT REPLACEMENT	1,743,653	
3	MAINS POOLS	1,032,943	
4	ALLOCATIONS - CAPITAL OVERHEAD	1,021,314	
5	PROJECTS LESS THAN $1 MILLION	4,268,315	
6	GENERAL PLANT		
7	PROJECTS LESS THAN $1 MILLION	1,104,853	
8	INTANGIBLE PLANT		
9	CUSTOMER CONNECT FUNDING PROJECT	3,583,886	
10	PROJECTS LESS THAN $1 MILLION	1,061,614	
11	PRODUCTION PLANT		
12	ELECTRIC AVE RS REPLACEMENT	1,380,350	
13	ROSSFORD AVE RS REPLACEMENT	1,367,466	
14	PROJECTS LESS THAN $1 MILLION	1,132,011	
15	TRANSMISSION PLANT		
16	PROJECTS LESS THAN $1 MILLION	387,801	
45	TOTAL	18,084,206	

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Non-Traditional Rate Treatment Afforded New Projects

1. The Commission's Certificate Policy Statement provides a threshold requirement for existing pipelines proposing new projects is that the pipeline must be prepared to financially support the project without relying on subsidization from its existing customers. See Certification of New Interstate Natural Gas Pipeline Facilities, 88 FERC P61,227 (1999); order clarifying policy, 90 FERC P61,128 (2000); order clarifying policy, 92 FERC P61,094 (2000) (Policy Statement). In column a, list the name of the facility granted non-traditional rate treatment.
2. In column b, list the CP Docket Number where the Commission authorized the facility.
3. In column c, indicate the type of rate treatment approved by the Commission (e.g. incremental, at risk)
4. In column d, list the amount in Account 101, Gas Plant in Service, associated with the facility.
5. In column e, list the amount in Account 108, Accumulated Provision for Depreciation of Gas Utility Plant, associated with the facility.
6. In column f, list the amount in Account 190, Accumulated Deferred Income Tax; Account 281, Accumulated Deferred Income Taxes – Accelerated Amortization Property; Account 282, Accumulated Deferred Income Taxes – Other Property; Account 283, Accumulated Deferred Income Taxes – Other, associated with the facility.
7. In column g, report the total amount included in the gas operations expense accounts during the year related to the facility (Account 401, Operation Expense).
8. In column h, report the total amount included in the gas maintenance expense accounts during the year related to the facility.
9. In column i, report the amount of depreciation expense accrued on the facility during the year.
10. In column j, list any other expenses(including taxes) allocated to the facility.
11. In column k, report the incremental revenues associated with the facility.
12. Identify the volumes received and used for any incremental project that has a separate fuel rate for that project.
13. Provide the total amounts for each column.

Line No.	Name of Facility (a)	CP Docket No. (b)	Type of Rate Treatment (c)	Gas Plant in Service (d)	Accumulated Depreciation (e)	Accumulated Deferred Income Taxes (f)	Operating Expense (g)	Maintenance Expense (h)	Depreciation Expense (i)	Other Expenses (including taxes) (j)	Incremental Revenues (k)
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37	Gas Plant In Service										

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

General Description of Construction Overhead Procedure

1. For each construction overhead explain: (a) the nature and extent of work, etc., the overhead charges are intended to cover, (b) the general procedure for determining the amount capitalized, (c) the method of distribution to construction jobs, (d) whether different rates are applied to different types of construction, (e) basis of differentiation in rates for different types of construction, and (f) whether the overhead is directly or indirectly assigned.
2. Show below the computation of allowance for funds used during construction rates, in accordance with the provisions of Gas Plant Instructions 3 (17) of the Uniform System of Accounts.
3. Where a net-of-tax rate for borrowed funds is used, show the appropriate tax effect adjustment to the computations below in a manner that clearly indicates the amount of reduction in the gross rate for tax effects.

1. CONSTRUCTION OVERHEAD COSTS INCLUDE ENGINEERING AND SUPERVISORY SALARIES, ADMINISTRATIVE AND GENERAL SALARIES AND ASSOCIATED PAYROLL TAXES AND BENEFITS AND EMPLOYEE EXPENSES.

IN GENERAL, IF ENGINEERS, SUPERVISORS, AND CLERICAL EMPLOYEES DEVOTE ALL OR SUBSTANTIALLY ALL OF THEIR TIME TO CAPITAL CONSTRUCTION PROJECTS, THE SALARIES AND RELATED EXPENSES ARE CHARGED DIRECTLY TO THE SPECIFIC CAPITAL CONSTRUCTION PROJECTS.
FOR POWER DELIVERY, CONSTRUCTION OVERHEAD COSTS ARE CHARGED TO THE ALLOCATION POOLS AND FROM THERE TRANSFERRED TO THE SPECIFIC CAPITAL CONSTRUCTION PROJECTS WHERE THE LABOR (INTERNAL AND CONTRACT) WAS CHARGED DURING THE MONTH.

2. ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC) IS APPLIED TO THE TOTAL CONSTRUCTION EXPENDITURES, LESS CERTAIN EXCLUSIONS, ON JOBS UNDER CONSTRUCTION. EFFECTIVE JULY 1, 1982, THE RESPONDENT ADOPTED THE PRACTICE OF UPDATING THE AFUDC RATE MONTHLY, AS AUTHORIZED BY THE FEDERAL ENERGY REGULATORY COMMISSION IN A LETTER DATED MAY 27, 1982. THE AVERAGE AFUDC RATE FOR 2021 WAS 2.62%. THE MONTHLY RATE DOES NOT INCLUDE A REDUCTION FOR THE INCOME TAX EFFECT ON THE COST OF DEBT.

COMPUTATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RATES

1. For line (5), column (e) below, enter the rate granted in the last rate proceeding. If not available, use the average rate earned during the preceding 3 years.
2. Identify in column (c), the specific entity used as the source for the capital structure figures.
3. Indicate in column (f), if the reported rate of return is one that has been approved in a rate case, black-box settlement rate, or an actual three-year average rate.

1. Components of Formula (Derived from actual book balances and actual cost rates):

Line No.	Title (a)	Amount (b)	Entity Name (c)	Capitalization Ration (percent) (d)	Cost Rate Percentage (e)	Rate Indicator (f)
	(1) Average Short-Term Debt	S				
	(2) Short-Term Interest				s	
	(3) Long-Term Debt	D			d	
	(4) Preferred Stock	P			p	
	(5) Common Equity	C			c	
	(6) Total Capitaization					
	(7) Average Construction Work in Progress Balance	W				

2. Gross Rate for Borrowed Funds s(S/W) + d[(D/(D+P+C)) (1-(S/W))] -
3. Rate for Other Funds [1-(S/W)] [p(P/(D+P+C)) + c(C/(D+P+C))] -
4. Weighted Average Rate Actually Used for the Year:
   (a) Rate for Borrowed Funds -
   (b) Rate for Other Funds -

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Accumulated Provision for Depreciation of Gas 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 12, column (c), and that reported for gas plant in service, page 204, column (d), excluding retirements of nondepreciable 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.
5. At lines 7 and 14, add rows as necessary to report all data. Additional rows should be numbered in sequence, e.g., 7.01, 7.02, etc.

Line No.	Item (a)	Total (c+d+e) (b)	Gas Plant in Service (c)	Gas Plant held for Future Use (d)	Gas Plant Leased to Others (e)
	Section A. BALANCES AND CHANGES DURING YEAR				
1	Balance Beginning of Year	179,966,949	179,966,949		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	15,977,765	15,977,765		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Expense of Gas Plant Leased to Others				
6	Transportation Expenses - Clearing	15,297	15,297		
7	Other Clearing Accounts				
8	Other Clearing (Specify) (footnote details):				
9.1	Other Clearing (Specify) (footnote details):				
9.2	Common Plant Depreciation	17,818	17,818		
9.3	ARO Depreciation deferred	79,271	79,271		
10	TOTAL Deprec. Prov. for Year (Total of lines 3 thru 8)	16,090,151	16,090,151		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(2,430,477)	(2,430,477)		
13	Cost of Removal	(2,896,052)	[a](2,896,052)		
14	Salvage (Credit)	6,411	6,411		
15	TOTAL Net Chrgs for Plant Ret. (Total of lines 12 thru 14)	(5,320,118)	(5,320,118)		
16	Other Debit or Credit Items (Describe in footnote details)				
17.1	Other Debit or Credit Items (Describe) (footnote details):				
17.2	Reserve Transfer to KO Transmission	(459,880)	(459,880)		
17.3	Reserve Transfer from Intangible Plant	792,033	792,033		
18	Book Cost of Asset Retirement Costs				
19	Balance End of Year (Total of lines 1,10,15,16 and 18)	191,069,135	191,069,135		

	Section B. BALANCES AT END OF YEAR ACCORDING TO FUNCTIONAL CLASSIFICATIONS				
21	Productions-Manufactured Gas	6,758,236	6,758,236		
22	Production and Gathering-Natural Gas				
23	Products Extraction-Natural Gas				
24	Underground Gas Storage				
25	Other Storage Plant				
26	Base Load LNG Terminaling and Processing Plant				
27	Transmission				
28	Distribution	183,409,106	183,409,106		
29	General	901,793	901,793		
30	TOTAL (Total of lines 21 thru 29)	191,069,135	191,069,135		

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FOOTNOTE DATA

(a) Concept: CostOfRemovalOfPlant

Intangible Retirements of $3,838,885 and General Plant Assets Retirements of $18,902 not reported on FERC Page 219.

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Gas Stored (Accounts 117.1, 117.2, 117.3, 117.4, 164.1, 164.2, and 164.3)

1. If during the year adjustments were made to the stored gas inventory reported in columns (d), (f), (g), and (h) (such as to correct cumulative inaccuracies of gas measurements), explain in a footnote the reason for the adjustments, the Dth and dollar amount of adjustment, and account charged or credited.
2. Report in (e) all encroachments during the year upon the volumes designated as base gas, column (b), and system balancing gas, column (c), and gas property recordable in the plant accounts.
3. State in a footnote the basis of segregation of inventory between current and noncurrent portions. Also, state in a footnote the method used to report storage (i.e., fixed asset method or inventory method).

Line No.	Description (a)	(Account 117.1) (b)	(Account 117.2) (c)	Noncurrent (Account 117.3) (d)	(Account 117.4) (e)	Current (Account 164.1) (f)	LNG (Account 164.2) (g)	LNG (Account 164.3) (h)	Total (i)
1	Balance at Beginning of Year								
2	Gas Delivered to Storage								
3	Gas Withdrawn from Storage								
4	Other Debits and Credits								
5	Balance at End of Year								
6	Dth								
7	Amount Per Dth								

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Investments (Account 123, 124, and 136)

1. Report below investments in Accounts 123, Investments in Associated Companies, 124, Other Investments, and 136, Temporary Cash Investments. List Account number in column (a).
2. Provide a subheading for each account and list thereunder the information called for: (a) Investment in Securities-List and describe each security owned, giving name of issuer, date acquired and date of maturity. For bonds, also give principal amount, date of issue, maturity, and interest rate. For capital stock (including capital stock of respondent reacquired under a definite plan for resale pursuant to authorization by the Board of Directors, and included in Account 124, Other Investments) state number of shares, class, and series of stock. Minor investments may be grouped by classes. Investments included in Account 136, Temporary Cash Investments, also may be grouped by classes. (b) Investment Advances-Report separately for each person or company the amounts of loans or investment advances that are properly includable in Account 123. Include advances subject to current repayment in Account 145 and 146. With respect to each advance, show whether the advance is a note or open account. List each note, giving date of issuance, maturity date, and specifying whether note is a renewal. Designate any advances due from officers, directors, stockholders, or employees.
3. Designate with an asterisk in column (b) any securities, notes or accounts that were pledged, and in a footnote state the name of pledges and purpose of the pledge.
4. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and cite Commission, date of authorization, and case or docket number.
5. Report in column (k) interest and dividend revenues from investments including such revenues from securities disposed of during the year.
6. In column (l) report for each investment disposed of during the year the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including any dividend or interest adjustment includible in column (k).

Line No.	Description of Investment (a)	* (b)	Date Acquired (c)	Date Matured (d)	Book Cost at Beginning of Year (If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference) (e)	Purchases or Additions During the Year (f)	Sales or Other Dispositions During Year (g)	Principal Amount (h)	No. of Shares at End of Year (i)	Book Cost at End of Year (If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference) (j)	Revenues for Year (k)	Gain or Loss from Investment Disposed of (l)
1												
2												
3												
4	Total Investment in Associated Companies											
1	124-9 Campbell County Business Dev. Corp		06/18/1962		1,500					1,500		
2	Total Other Investments				1,500					1,500		
1												
2												
3												
4	Total Temporary Cash Investments											
4	Total Investments				1,500					1,500		

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Investments in Subsidiary Companies (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder the information called for below. Sub-total by company and give a total in columns (e), (f), (g) and (h). (a) Investment in Securities-List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The total in column (e) should equal the amount entered for Account 418.1.
4. Designate in a footnote, any securities, notes, or accounts that were pledged, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report in column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost), and the selling price thereof, not including interest adjustments includible in column (f).
8. Report on Line 40, column (a) the total cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary earnings for Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
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26								
27								
28								
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31								
32								
33								
34								
35								
36								
37								
38								
39								
40	TOTAL Cost of Account 123.1 $		Total					

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Prepayments (Acct 165), Extraordinary Property Losses (Acct 182.1), Unrecovered Plant and Regulatory Study Costs (Acct 182.2)

PREPAYMENTS (ACCOUNT 165)

1. Report below the particulars (details) on each prepayment.

Line No.	Nature of Payment (a)	Balance at End of Year (in dollars) (b)
1	Prepaid Insurance	
2	Prepaid Rents	
3	Prepaid Taxes	
4	Prepaid Interest	
5	Miscellaneous Prepayments	1,293,933
6	TOTAL	1,293,933

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Prepayments (Acct 165), Extraordinary Property Losses (Acct 182.1), Unrecovered Plant and Regulatory Study Costs (Acct 182.2) (continued)

EXTRAORDINARY PROPERTY LOSSES (ACCOUNT 182.1)

1. Include the date of loss, the date of Commission authorization to use Account 182.1 and period of amortization (mo, yr, to mo, yr)].
2. Add rows as necessary to report all data. Number rows in sequence beginning with the next row number after the last row number used for extraordinary property losses.

Line No.	Description of Extraordinary Loss [include the date of loss, the date of Commission authorization to use Account 182.1 and period of amortization (mo, yr, to mo, yr)] Add rows as necessary to report all data. (a)	Balance at Beginning of Year (b)	Total Amount of Loss (c)	Losses Recognized During Year (d)	Written off During Year Account Charged (e)	Written off During Year Amount (f)	Balance at End of Year (g)
7							
8							
9							
10							
11							
12							
13							
14							
15	TOTAL						

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Prepayments (Acct 165), Extraordinary Property Losses (Acct 182.1), Unrecovered Plant and Regulatory Study Costs (Acct 182.2) (continued)

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (ACCOUNT 182.2)

1. Include in the description of costs, the date of Commission authorization to use Account 182.2 and period of amortization (mo, yr, to mo, yr).
2. Add rows as necessary to report all data. Number rows in sequence beginning with the next row number after the last row number used for extraordinary property losses.

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission authorization to use Account 182.2 and period of amortization (mo, yr, to mo, yr)] Add rows as necessary to report all data. Number rows in sequence beginning with the next row number after the last row number used for extraordinary property losses. (a)	Balance at Beginning of Year (b)	Total Amount of Charges (c)	Costs Recognized During Year (d)	Written off During Year Account Charged (e)	Written off During Year Amount (f)	Balance at End of Year (g)
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26	TOTAL						

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Other Regulatory Assets (Account 182.3)

1. Report below the details called for concerning other regulatory assets which are created through the ratemaking actions of regulatory agencies (and not includable in other accounts).
2. For regulatory assets being amortized, show period of amortization in column (b).
3. Minor items (5% of the Balance at End of Year for Account 182.3 or amounts less than $250,000, whichever is less) may be grouped by classes.
4. Report separately any "Deferred Regulatory Commission Expenses" that are also reported on pages 350-351, Regulatory Commission Expenses.
5. Provide in column (c), for each line item, the regulatory citation where authorization for the regulatory asset has been granted (e.g. Commission Order, state commission order, court decision).

Line No.	Description and Purpose of Other Regulatory Assets (a)	Amortization Period (b)	Regulatory Citation (c)	Balance at Beginning Current Quarter/Year (d)	Debits (e)	Written off During Quarter/Year Account Charged (f)	Written off During Period Amount Recovered (g)	Written off During Period Amount Deemed Unrecoverable (h)	Balance at End of Current Quarter/Year (i)
1	INCOME TAXES			5,667,313		282, 283	38,172		5,629,141
2	DEMAND SIDE MANAGEMENT COSTS-(Amortized in accordance with rider revenue)--		Order #2017-321-- Order #2015-368-- Order #2014-388	1,300,207	3,384,549				4,684,756
3	INTEREST RATE HEDGES	Amortized over life of associated debt	Order #2006-563	5,290,232	(1,596,353)				3,693,879
4	ESM DEFERRAL--		Order #2017-321	4,130,216	(1,946,504)				2,183,712
5	FTR DEFERRAL								
6	REPS INCREMENTAL COSTS			(829)	829				
7	ARO OTHER REGULATORY ASSET			275,020	1,636				276,656
8	GAS ARO OTHER REGULATORY ASSET			6,401,669	508,617				6,910,286
9	ARO CONTRA-REGULATORY ASSET		Order #2017-321	(718,030)	(270,029)				(988,059)
10	COAL ASH DEFERRED SPEND--		Order #2015-187	974,145	108,551				1,082,696
11	COAL ASH ARO--		Order #2015-187	7,640,207	11,044,537				18,684,744
12	COAL ASH CONTRA EQUITY-		Order #2017-321	(713,899)	94,620				(619,279)
13	SPEND RA AMORTIZATION (NC & MW)--		Order #2017-321	13,589,245		182.3, 407.3, 421, 431	1,391,902		12,197,343
14	SPEND RA AMORTIZATION (SC & FL)--		Order #2017-321	718,674	2,315,895	407.3	1,603,757		1,430,812
15	DEK DEFERRED STORM EXPENSE-		Order #2018-416	910,913		593	210,211		700,702
16	CARBON MANAGEMENT REGULATORY ASSET	120 months beginning May 2018	Order #2017-321-Order #2008-308	1,466,637		407.3	199,996		1,266,641
17	HURRICANE IKE REGULATORY ASSET-	60 months beginning May 2018	Order #2017-321-Order #2008-476	2,292,584		407.3	982,536		1,310,048
18	EAST BEND PLANT O&M DEFERRAL-	120 months beginning May 2018	Order #2017-321-Order #2014-201	30,000,243		407.3, 407.4	3,280,670		26,719,573
19	EAST BEND DEPRECIATION DEFERRAL	Remaining Life of Asset	Order #2015-120	10,198,885		403	490,618		9,708,267
20	Non-AMI Meter NBV	146 months beginning May 2018	Order #2017-321	3,867,037		154, 407.3, 421	368,588		3,498,449
21	Opt-Out IT Modification	60 months beginning May 2018	Order #2017-321-Order #2016-152	73,360		407.3	31,440		41,920
22	Plant Outage Normalization-		Order #2017-321	4,438,156	3,871,108				8,309,264

23	Deferred Forced Outage Purchased Power		Order #2017-321		83,791				83,791
24	GAS RATE CASE DEFERRAL	60 months beginning April 2019	Order#2018-261	165,852		928	51,031		114,821
25	DEFERRED GAS INTEGRITY COSTS	120 months beginning April 2018	Order#2018-261Order #2106-159	2,468,113		407.3, 407.4	254,153		2,213,960
26	OTHER REGULATORY ASSETS - GENERAL ACCOUNTING-		FERC Docket A107-1-000	30,464,476		128, 182.3, 228, 926	3,902,544		26,561,932
27	PENSION POST RETIRE PURCHASE ACCOUNTING - Q--		FERC Docket A107-1-000	3,565,128	39,355	128, 182.3, 228, 926	205,044		3,399,439
28	PENSION POST RETIRE PURCHASE ACCOUNTING - NQ--		FERC Docket A107-1-000	50,426		253, 926	4,334		46,092
29	PENSION POST RETIRE PURCHASE ACCOUNTING - FAS		FERC Docket A107-1-000	1,634,422		228, 254, 926	187,536		1,446,886
30	Misc/ ST Reg Assets				44,939				44,939
40	TOTAL			136,150,402	17,685,541		13,202,532		140,633,411

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Miscellaneous Deferred Debits (Account 186)

1. Report below the details called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (b).
3. Minor items (less than $250,000) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Amortization Period (b)	Balance at Beginning of Year (c)	Debits (d)	Credits Account Charged (e)	Credits Amount (f)	Balance at End of Year (g)
1	Vacation Accrual		1,324,241	(81,762)			1,242,479
2	Straight Line Lease Deferral	amortized 01/20 - 12/38	203,748	761,352	242	676,033	289,067
3	DEK 2017 Rate Case - Electric	amortized 05/18 - 04/23	341,859		928	85,465	256,394
4	DEK 2019 Rate Case - Electric	amortized 05/20 - 04/25	293,946		928	67,834	226,112
5	DEK 2021 Rate Case - Gas	amortized 01/22 - 12/27		145,139			145,139
6	Indirect overhead allocation pool undistributed		(7,654)	64,152			56,498
39	Miscellaneous Work in Progress						
40	TOTAL		2,156,140	888,881		829,332	2,215,689

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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.
3. Provide in a footnote a summary of the type and amount of deferred income taxes reported in the beginning-of-year and end-of-year balances for deferred income taxes that the respondent estimates could be included in the development of jurisdictional recourse rates.

Line No.	Account Subdivisions (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)	Changes During Year Amounts Debited to Account 410.2 (e)	Changes During Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Account No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1	Account 190										
2	Electric	55,843,006	5,540,849	4,753,049	398,009			905,958			53,751,239
3	Gas	17,377,717	1,737,388	1,679,923				349,367			16,970,885
4	Other (Define)										
5	Total (Total of lines 2 thru 4)	73,220,723	7,278,237	6,432,972	398,009			1,255,325			70,722,124
6	Other (Specify)										
7	TOTAL Account 190 (Total of lines 5 thru 6)	73,220,723	7,278,237	6,432,972	398,009			1,255,325			70,722,124
8	Classification of TOTAL										
9	Federal Income Tax	59,787,852	6,484,845	5,209,287	318,671			1,393,406			56,800,217
10	State Income Tax	13,432,871	793,392	1,223,685	79,338			(138,081)			13,921,907
11	Local Income Tax										

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Capital Stock (Accounts 201 and 204)

1. Report below the details called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock.
2. Entries in column (c) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Exchange (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)	Outstanding per Bal. Sheet (total amt outstanding without reduction for amts held by respondent) Shares (e)	Outstanding per Bal. Sheet Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2	Common Stock	1,000,000	15.00		585,333	8,779,995				
3										
4										
5	Total	1,000,000			585,333	8,779,995				
6	Preferred Stock (Account 204)									
7										
8										
9										
10	Total									
11	Total									

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Capital Stock: Subscribed, Liability for Conversion, Premium on, and Installments Received on (Accts 202, 203, 205, 206, 207, and 212)

1. Show for each of the above accounts the amounts applying to each class and series of capital stock.
2. For Account 202, Common Stock Subscribed, and Account 205, Preferred Stock Subscribed, show the subscription price and the balance due on each class at the end of year.
3. Describe in a footnote the agreement and transactions under which a conversion liability existed under Account 203, Common stock Liability for Conversion, or Account 206, Preferred Stock Liability for Conversion, at the end of year.
4. For Premium on Account 207, Capital Stock, designate with an asterisk in column (b), any amounts representing the excess of consideration received over stated values of stocks without par value.

Line No.	Name of Account and Description of Item (a)	* (b)	Number of Shares (c)	Amount (d)
1	Common Stock, Subscribed (Account 202)			
2				
3				
4				
5	Total			
6	Common Stock, Converted to Liability (Account 203)			
7				
8				
9				
10	Total			
11	Preferred Stock, Subscribed (Account 205)			
12				
13				
14				
15	Total			
16	Preferred Stock Liability for Conversion (Account 206)			
17				
18				
19				
20	Total			
21	Premium on Capital Stock (Account 207)			
22	Premium $15 per Share on Capital Stock in 1955	*	62,419	936,287
23	Premium $17 per Share on Capital Stock in 1957	*	104,000	1,768,003
24	Premium $38 per Share on Capital Stock in 1961	*	69,333	2,634,656
25	Premium $135 per Share on Capital Stock in 1992	*	100,000	13,500,000

26	Total		335,752.00	18,838,946.00
27	Installments on Capital Stock (Account 212)			
28				
29				
30				
31	Total			
40	Total		335,752.00	18,838,946.00

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Other Paid-In Capital (Accounts 208-211)

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

a. Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
b. Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
c. Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
d. Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	148,811,383
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	148,811,383
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	74,843,806
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	[a]50,000,000
16	Ending Balance Amount	124,843,806
17	**Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	273,655,189

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: IncreasesDecreasesDueToMiscellaneousPaidInCapital
Equity infusion of $50M from Parent.

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

DISCOUNT ON CAPITAL STOCK (ACCOUNT 213)

1. Report the balance at end of year of discount on capital stock for each class and series of capital stock. Use as many rows as necessary to report all data.
2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving details of the change. State the reason for any charge-off during the year and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15	Total	

Capital Stock Expense (Account 214)

1. Report the balance at end of year of capital stock expenses for each class and series of capital stock. Use as many rows as necessary to report all data. Number the rows in sequence starting from the last row number used for Discount on Capital Stock above.
2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving details of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
16		
17		
18		
19		
20		
21		

22		
23		
24		
25		
26		
27		
28		
29	Total	

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Securities Issued or Assumed and Securities Refunded or Retired During the Year

1. Furnish a supplemental statement briefly describing security financing and refinancing transactions during the year and the accounting for the securities, discounts, premiums, expenses, and related gains or losses. Identify as to Commission authorization numbers and dates.
2. Provide details showing the full accounting for the total principal amount, par value, or stated value of each class and series of security issued, assumed, retired, or refunded and the accounting for premiums, discounts, expenses, and gains or losses relating to the securities. Set forth the facts of the accounting clearly with regard to redemption premiums, unamortized discounts, expenses, and gain or losses relating to securities retired or refunded, including the accounting for such amounts carried in the respondent's accounts at the date of the refunding or refinancing transactions with respect to securities previously refunded or retired.
3. Include in the identification of each class and series of security, as appropriate, the interest or dividend rate, nominal date of issuance, maturity date, aggregate principal amount, par value or stated value, and number of shares. Give also the issuance of redemption price and name of the principal underwriting firm through which the security transactions were consummated.
4. Where the accounting for amounts relating to securities refunded or retired is other than that specified in General Instruction 17 of the Uniform System of Accounts, cite the Commission authorization for the different accounting and state the accounting method.
5. For securities assumed, give the name of the company for which the liability on the securities was assumed as well as details of the transactions whereby the respondent undertook to pay obligations of another company. If any unamortized discount, premiums, expenses, and gains or losses were taken over onto the respondent's books, furnish details of these amounts with amounts relating to refunded securities clearly earmarked.

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Long-Term Debt (Accounts 221, 222, 223, and 224)

1. Report by Balance Sheet Account the details concerning long-term debt included in Account 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt.
2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued.
5. In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a)principal advanced during year (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (f). Explain in a footnote any difference between the total of column (f) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation and Name of Stock Exchange (a)	Nominal Date of Issue (b)	Date of Maturity (c)	Outstanding (Total amount outstanding without reduction for amts held by respondent) (d)	Interest for Year Rate (in %) (e)	Interest for Year Amount (f)	Held by Respondent Reacquired Bonds (Acct 222) (g)	Held by Respondent Sinking and Other Funds (h)	Redemption Price per $100 at End of Year (i)
1	Bonds (Account 221)								
2									
3									
4									
5									
6									
7									
8									
9									
10	Subtotal								
11	Reacquired Bonds (Account 222)								
12									
13									
14									
15									
16									
17									
18									
19									
20	Subtotal								

21	Advances from Associated Companies (Account 223)								
22	INTERCOMPANY MONEYPOOL NOTES PAYABLE - LONG TERM	12/15/2014	03/16/2026	25,000,000	(a)0.235%	141,453			
23	Subtotal			25,000,000		141,453			
24	Other Long Term Debt (Account 224)								
25	UNSECURED DEBENTURES 6.20% SERIES B DUE IN 2036	03/07/2006	03/10/2036	65,000,000	6.2%	4,030,000			(f)0.30
26	(b) POLLUTION CONTROL REFUNDING BONDS 2008 SERIES A DUE IN 2027	12/11/2008	11/01/2021			465,900			1.00
27	POLLUTION CONTROL REFUNDING BONDS 2010 SERIES A DUE IN 2027	11/24/2010	08/01/2027	26,720,000	(d)0.12%	44,655			(g)1.00
28	UNSECURED DEBENTURES 3.42% DUE IN 2026	01/05/2016	01/15/2026	45,000,000	3.42%	1,539,000			(h)0.25
29	UNSECURED DEBENTURES 4.45% DUE IN 2046	01/05/2016	01/15/2046	50,000,000	4.45%	2,225,000			(i)0.50
30	UNSECURED DEBENTURES 3.35% DUE IN 2029	09/07/2017	09/15/2029	30,000,000	3.35%	1,005,000			(j)0.50
31	UNSECURED DEBENTURES 4.11% DUE IN 2047	09/07/2017	09/15/2047	30,000,000	4.11%	1,233,000			(k)0.50
32	UNSECURED DEBENTURES 4.26% DUE IN 2057	09/07/2017	09/15/2047	30,000,000	4.26%	1,278,000			(l)0.50
33	UNSECURED DEBENTURES 4.01% DUE IN 2023	10/03/2018	10/15/2023	25,000,000	4.01%	1,002,500			(m)0.50
34	UNSECURED DEBENTURES 4.18% DUE IN 2028	10/03/2018	10/15/2028	40,000,000	4.18%	1,672,000			(n)0.50
35	UNSECURED DEBENTURES 4.62% DUE IN 2048	12/12/2018	12/15/2048	35,000,000	4.62%	1,617,000			(o)0.50
36	UNSECURED DEBENTURES 4.32% DUE IN 2049	07/17/2019	07/15/2049	40,000,000	4.32%	1,728,000			(p)0.50
37	UNSECURED DEBENTURES 3.23% DUE IN 2025	09/26/2019	10/01/2025	95,000,000	3.23%	3,068,500			(q)0.50
38	UNSECURED DEBENTURES 3.56% DUE IN 2029	09/26/2019	10/01/2029	75,000,000	3.56%	2,670,000			(r)0.50
39	UNSECURED DEBENTURES 2.65% DUE IN 2030	09/15/2020	09/15/2030	35,000,000	2.65%	927,500			(s)0.50
40	UNSECURED DEBENTURES 3.66% DUE IN 2050	09/15/2020	09/15/2050	35,000,000	3.66%	1,281,000			(t)0.50
41	TERM LOAN DUE IN 2023, .650%	10/12/2021	10/12/2023	50,000,000	(e)0.65%	73,029			(u)0.60
42	(c) See Footnote								
26	Subtotal			706,720,000		25,860,084			
40	TOTAL			731,720,000		26,001,537			

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: InterestRate

The interest rate varies on this note. The interest rate is as of December 31, 2021.

(b) Concept: ClassOfSeriesOfObligationAndNameOfStockExchange

Bonds purchased back on 11/1/2021 originally scheduled to mature on 8/1/2027

(c) Concept: ClassOfSeriesOfObligationAndNameOfStockExchange

On December 2, 2020 the Kentucky PSC approved Duke Energy Kentucky's long-term financing application authorizing the issuance of up to $250 million of secured and/or unsecured notes, and $76.72 million of tax-exempt private activity bonds to refund existing tax exempt bonds. Authorization expires 12/31/2022.

(d) Concept: InterestRate

The interest rate varies on this pollution control bond. The interest rate is as of December 31, 2021.

(e) Concept: InterestRate

The interest rate varies on this term loan bond. The interest rate is as of December 31, 2021.

(f) Concept: RedemptionPrice

Redemption price of the Debenture is based on the present value of the future interest and principal payments discounted at a rate equal to the yield of US government securities with a maturity similar to the Debenture plus a certain spread.This spread is presented in Column (i) and is shown as basis points in percentages. The calculated redemption price can never be less than $100.

(g) Concept: RedemptionPrice

This PCB is redeemable at par ($100) and is not subject to the redemption calculation.

(h) Concept: RedemptionPrice

Redemption price of the Debenture is based on the present value of the future interest and principal payments discounted at a rate equal to the yield of US government securities with a maturity similar to the Debenture plus a certain spread.This spread is presented in Column (i) and is shown as basis points in percentages. The calculated redemption price can never be less than $100.

(i) Concept: RedemptionPrice

Redemption price of the Debenture is based on the present value of the future interest and principal payments discounted at a rate equal to the yield of US government securities with a maturity similar to the Debenture plus a certain spread.This spread is presented in Column (i) and is shown as basis points in percentages. The calculated redemption price can never be less than $100.

(j) Concept: RedemptionPrice

Redemption price of the Debenture is based on the present value of the future interest and principal payments discounted at a rate equal to the yield of US government securities with a maturity similar to the Debenture plus a certain spread.This spread is presented in Column (i) and is shown as basis points in percentages. The calculated redemption price can never be less than $100.

(k) Concept: RedemptionPrice

Redemption price of the Debenture is based on the present value of the future interest and principal payments discounted at a rate equal to the yield of US government securities with a maturity similar to the Debenture plus a certain spread.This spread is presented in Column (i) and is shown as basis points in percentages. The calculated redemption price can never be less than $100.

(l) Concept: RedemptionPrice

Redemption price of the Debenture is based on the present value of the future interest and principal payments discounted at a rate equal to the yield of US government securities with a maturity similar to the Debenture plus a certain spread.This spread is presented in Column (i) and is shown as basis points in percentages. The calculated redemption price can never be less than $100.

(m) Concept: RedemptionPrice

Redemption price of the Debenture is based on the present value of the future interest and principal payments discounted at a rate equal to the yield of US government securities with a maturity similar to the Debenture plus a certain spread.This spread is presented in Column (i) and is shown as basis points in percentages. The calculated redemption price can never be less than $100.

(n) Concept: RedemptionPrice

Redemption price of the Debenture is based on the present value of the future interest and principal payments discounted at a rate equal to the yield of US government securities with a maturity similar to the Debenture plus a certain spread.This spread is presented in Column (i) and is shown as basis points in percentages. The calculated redemption price can never be less than $100.

(o) Concept: RedemptionPrice

Redemption price of the Debenture is based on the present value of the future interest and principal payments discounted at a rate equal to the yield of US government securities with a maturity similar to the Debenture plus a certain spread.This spread is presented in Column (i) and is shown as basis points in percentages. The calculated redemption price can never be less than $100.

(p) Concept: RedemptionPrice

Redemption price of the Debenture is based on the present value of the future interest and principal payments discounted at a rate equal to the yield of US government securities with a maturity similar to the Debenture plus a certain spread.This spread is presented in Column (i) and is shown as basis points in percentages. The calculated redemption price can never be less than $100.

(q) Concept: RedemptionPrice

Redemption price of the Debenture is based on the present value of the future interest and principal payments discounted at a rate equal to the yield of US government securities with a maturity similar to the Debenture plus a certain spread.This spread is presented in Column (i) and is shown as basis points in percentages. The calculated redemption price can never be less than $100.

(r) Concept: RedemptionPrice
Redemption price of the Debenture is based on the present value of the future interest and principal payments discounted at a rate equal to the yield of US government securities with a maturity similar to the Debenture plus a certain spread.This spread is presented in Column (i) and is shown as basis points in percentages. The calculated redemption price can never be less than $100.
(s) Concept: RedemptionPrice
Redemption price of the Debenture is based on the present value of the future interest and principal payments discounted at a rate equal to the yield of US government securities with a maturity similar to the Debenture plus a certain spread.This spread is presented in Column (i) and is shown as basis points in percentages. The calculated redemption price can never be less than $100.
(t) Concept: RedemptionPrice
Redemption price of the Debenture is based on the present value of the future interest and principal payments discounted at a rate equal to the yield of US government securities with a maturity similar to the Debenture plus a certain spread.This spread is presented in Column (i) and is shown as basis points in percentages. The calculated redemption price can never be less than $100.
(u) Concept: RedemptionPrice
Redemption price of the Debenture is based on the present value of the future interest and principal payments discounted at a rate equal to the yield of US government securities with a maturity similar to the Debenture plus a certain spread.This spread is presented in Column (i) and is shown as basis points in percentages. The calculated redemption price can never be less than $100.

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Unamortized Debt Expense, Premium and Discount on Long-Term Debt (Accounts 181, 225, 226)

1. Report under separate subheadings for Unamortized Debt Expense, Unamortized Premium on Long-Term Debt and Unamortized Discount on Long-Term Debt, details of expense, premium or discount applicable to each class and series of long-term debt.
2. Show premium amounts by enclosing the figures in parentheses.
3. In column (b) show the principal amount of bonds or other long-term debt originally issued.
4. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
5. Furnish in a footnote details regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.
6. Identify separately undisposed amounts applicable to issues which were redeemed in prior years.
7. Explain any debits and credits other than amortization debited to Account 428, Amortization of Debt Discount and Expense, or credited to Account 429, Amortization of Premium on Debt-Credit.

Line No.	Designation of Long-Term Debt (a)	Principal Amount of Debt Issued (b)	Total expense - Premium; Discount; or Debt Issuance Costs (c)	Amortization Period Date From (d)	Amortization Period Date To (e)	Balance at Beginning of Year (f)	Debits During Year (g)	Credits During Year (h)	Balance at End of Year (i)
1	Unamortized Debt Expense (Account 181)								
2	POLLUTION CONTROL BONDS 2010 SERIES A DUE IN 2027	26,720,000	939,966	11/24/2010	08/01/2027	155,316		38,683	116,633
3	POLLUTION CONTROL BONDS 2008 SERIES A DUE IN 2027	50,000,000	691,754	12/03/2008	08/01/2027	155,231		155,231	
4	TERM LOAN .650% DUE IN 2023	50,000,000		10/12/2021	10/12/2023		21,915		21,915
5	UNSECURED DEBENTURES 6.20% SERIES B DUE IN 2036	65,000,000	653,550	03/10/2006	03/10/2036	330,957		21,784	309,173
6	UNSECURED DEBENTURES 3.42% SERIES A DUE IN 2026	45,000,000	220,191	01/05/2016	01/15/2026	119,981		23,811	96,170
7	UNSECURED DEBENTURES 4.45% SERIES A DUE IN 2046	50,000,000	247,535	01/05/2016	01/15/2046	221,993		8,866	213,127
8	UNSECURED DEBENTURES 3.35% SERIES A DUE IN 2029	30,000,000	124,475	09/07/2017	09/15/2029	90,135		10,354	79,781
9	UNSECURED DEBENTURES 4.11% SERIES A DUE IN 2047	30,000,000	124,475	09/07/2017	09/15/2047	110,724		4,146	106,578
10	UNSECURED DEBENTURES 4.26% SERIES A DUE IN 2057	30,000,000	124,475	09/07/2017	09/15/2057	114,160		3,110	111,050
11	UNSECURED DEBENTURES 4.01% SERIES A DUE IN 2023	25,000,000	111,522	10/03/2018	10/15/2023	53,385		22,157	31,228
12	UNSECURED DEBENTURES 4.18% SERIES A DUE IN 2028	40,000,000	156,522	10/03/2018	10/15/2028	108,061		15,600	92,461
13	UNSECURED DEBENTURES 4.62% SERIES A DUE IN 2048	35,000,000	141,522	12/12/2018	12/15/2048	120,074		4,716	115,358
14	UNSECURED DEBENTURES 4.32% SERIES A DUE IN 2049	40,000,000	195,082	07/17/2019	07/15/2049	196,055		6,546	189,509
15	UNSECURED DEBENTURES 3.23% SERIES A DUE IN 2025	95,000,000	415,082	09/26/2019	10/01/2025	349,748		69,021	280,727
16	UNSECURED DEBENTURES 3.56% SERIES A DUE IN 2029	75,000,000	335,082	09/26/2019	10/01/2029	310,312		33,462	276,850
17	UNSECURED DEBENTURES 2.65% SERIES A DUE IN 2030	35,000,000	127,283	09/15/2020	09/15/2030	149,466		12,728	136,738
18	UNSECURED DEBENTURES 3.66% SERIES A DUE IN 2050	35,000,000	127,283	09/15/2020	09/15/2050	151,964		4,243	147,721
19	[a] MASTER CREDIT FACILITY		454,094	11/18/2011	03/16/2026	377,221	108,719	92,791	393,149
20	TOTAL 181	756,720,000				3,114,783	130,634	527,249	2,718,168
21	Premium on Long-Term Debt (Account 225)								
22									

23									
24									
25	Discount on Long-Term Debt (Account 226)								
26	UNSECURED DEBENTURES 6.20% SERIES B DUE IN 2036	65,000,000	367,900	03/10/2006	03/10/2036	186,301		12,263	174,038

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: DesignationOfLongTermDebt

In March 2021, Duke Energy amended its existing $8 billion Master Credit Facility to extend the termination date to March 2026. The Duke Energy Registrants, excluding Progress Energy, have borrowing capacity under the Master Credit Facility up to a specified sublimit for each borrower. Duke Energy Kentucky has a $175 million borrowing limit as of December 31, 2021.

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Unamortized Loss and Gain on Reacquired Debt (Accounts 189, 257)

1. Report under separate subheadings for Unamortized Loss and Unamortized Gain on Reacquired Debt, details of gain and loss, including maturity date, on reacquisition applicable to each class and series of long-term debt. If gain or loss resulted from a refunding transaction, include also the maturity date of the new issue.
2. In column (d) show the principal amount of bonds or other long-term debt reacquired.
3. In column (e) show the net gain or net loss realized on each debt reacquisition as computed in accordance with General Instruction 17 of the Uniform Systems of Accounts.
4. Show loss amounts by enclosing the figures in parentheses.
5. Explain in a footnote any debits and credits other than amortization debited to Account 428.1, Amortization of Loss on Reacquired Debt, or credited to Account 429.1, Amortization of Gain on Reacquired Debt-Credit.

Line No.	Designation of Long-Term Debt (a)	Date of Maturity (b)	Date Reacquired (c)	Principal of Debt Reacquired (d)	Net Gain or Loss (e)	Balance at Beginning of Year (f)	Balance at End of Year (g)
1	Unamortized Loss (Account 189)						
2	7.65% SERIES		04/06/2006	15,000,000	(1,230,503)	(290,206)	(226,268)
3	5.5% SERIES		09/01/2006	48,000,000	(669,996)	(115,961)	(77,307)
4	6.5% SERIES		09/01/2006	12,720,663	(73,931)	(8,543)	(3,980)
5	2006A SERIES		12/26/2008	50,000,000	(289,319)	(102,494)	(86,926)
6	Unamortized Gain (Account 257)						
7	Total 189			125,720,663	(2,263,749)	(517,204)	(394,481)
8	Total 257						

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ 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 that files consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group members, tax assigned to each group member, and basis of allocation, assignments, or sharing of the consolidated tax among the group members.

Line No.	Details (a)	Amount (b)
1	Net Income for the Year (Page 114)	53,405,580
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Contributions in Aid of Construction	2,069,093
8	Total	2,069,093
9	Deductions Recorded on Books Not Deducted for Return	
10	Federal & State Income Tax Deducted for Books	10,059,978
11	Other Deductions Recorded on Books Not Deducted for Return	
12	T13A08: Book Depreciation/Amortization	72,480,885
13	T13B45: Asset Retirement Obligation - Coal Ash	14,857,543
14	T22H47: Coal Ash Capitalized for Tax	5,305,890
15	T20A38: Regulatory Asset - Deferred Plant Costs	3,913,226
16	T15B29: Reg Asset-Pension Post Retirement PAA-FAS87Qual and Oth	3,183,879
17	T13B08: ASSET RETIREMENT OBLIGATION	2,313,176
18	T13B31: Impairment of Plant Assets	2,271,499
19	T19A71: Reg Asset/Liab - ESM Deferral	2,216,533
20	T15B07: Cash Flow Hedge - Reg Asset/Liab	1,596,353
21	T13A26: Tax Interest Capitalized	1,584,789
22	T22H54: Coal Ash Spend Reg Asset Approved - Retail (NC & MW)	1,391,902
23	Other	5,391,216
13	Total	126,566,869
14	Income Recorded on Books Not Included in Return	
15	Allowance for Funds Used During Construction	1,709,537
18	Total	1,709,537

19	Deductions on Return Not Charged Against Book Income	
20	T13B33: T & D Repairs - Annual Adj.	27,650,000
21	T15B02: Reg Asset/Liab Def Revenue	18,090,156
22	T13B26: Equipment Repairs - Annual Adj	16,820,000
23	T13A16: Cost of Removal	14,616,002
24	T22H46: ARO Regulatory Asset - Coal Ash	11,044,537
25	T13A30: Tax Gains/Losses	5,300,000
26	T19A94: UNBILLED REVENUE - FUEL	4,642,502
27	T15B81: Reg Asset_Liab - Outage Costs	3,954,899
28	T22H45: Asset Retirement Costs - Coal Ash	3,813,006
29	T22A23: Retirement Plan Expense - Overfunded	3,529,616
30	T22B16: Miscellaneous NC Taxable Income Adj - DTL	3,343,574
31	T22H11: Asset Retirement Costs - ARO	1,802,923
32	T17A30: Property Tax Reserves	1,610,361
33	T15A22: Mark to Market - LT	1,596,821
34	T13A28: Tax Depreciation/Amortization	73,200,000
35	Other	5,565,766
36	State Tax Deduction - Deduction on Return Not Charged Against Book Inc	(1,845,360)
26	Total	194,734,803
27	Federal Tax Net Income	(14,402,798)
28	Show Computation of Tax:	
29	Provision for Federal Income Tax @ 21%	(3,024,588)
30	NOL's	(3,258,725)
31	True Up Entries	(670,739)
32	Other Benefits	(173)
33	Total Federal Income Tax	(6,954,225)

Name of Respondent:	This report is:	Date of Report:	Year/Period of Report:
Duke Energy Kentucky, Inc	(1) ☑ An Original (2) ☐ A Resubmission	04/18/2022	End of: 2021/ Q4

Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged)

1. Give details of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes). Enter the amounts in both columns (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (g) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to the portion of prepaid taxes charged 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.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a footnote. 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. Show in columns (l) thru (s) how the taxes accounts were distributed. Show both the utility department and number of account charged. For taxes charged to utility plant, show the number of the appropriate balance sheet plant account or subaccount.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.
10. Items under $250,000 may be grouped.
11. Report in column (t) the applicable effective state income tax rate.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	Tax Jurisdiction (c)	Tax Year (d)	Balance at Beg. of Year Taxes Accrued (e)	Balance at Beg. of Year Prepaid Taxes (f)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	Balance at End of Year Taxes Accrued (Account 236) (j)	Balance at End of Year Prepaid Taxes (Included in Acct 165) (k)	Electric (Account 408.1, 409.1) (l)	Gas (Account 408.1, 409.1) (m)	Other Utility Dept. (Account 408.1, 409.1) (n)	Other Income and Deductions (Account 408.2, 409.2) (o)	Extraordinary Items (Account 409.3) (p)	Other Utility Opn. Income (Account 408.1, 409.1) (q)	Adjustment to Ret. Earnings (Account 439) (r)	Other (s)	State/Local Income Tax Rate (t)
1	Fed Insurance Tax	Federal Insurance Tax	Federal	2021	848,904		2,120,235	2,749,308	(3,489)	216,342		1,778,252	341,982							
2	Fed Fuel Tax	Fuel Tax	Federal	2021																
3	**Subtotal Federal Tax**				848,904		2,120,235	2,749,308	(3,489)	216,342		1,778,252	341,982							
4	Local Property Tax	Property Tax	KY	2021	12,855,322		18,823,607	16,664,709	(189,172)	14,825,048		14,497,979	4,325,628							
5	Property Tax	Property Tax	KY	2021	2,604,132					2,604,132										
6	**Subtotal Property Tax**				15,459,454		18,823,607	16,664,709	(189,172)	17,429,180		14,497,979	4,325,628							
7	Unemployment	Unemployment Tax	Federal	2021	66		8,753	8,182		637		6,279	2,474							
8	Unemployment	Unemployment Tax	KY	2021	103		18,898	18,421		580		13,543	5,355							
9	**Subtotal Unemployment Tax**				169		27,651	26,603		1,217		19,822	7,829							
10	Sales and Use	Sales And Use Tax	KY	2021	225,892		(473,967)	(1,909,020)	(1,517,150)	143,795		(453,946)	(18,845)		(1,176)					
11	**Subtotal Sales And Use Tax**				225,892		(473,967)	(1,909,020)	(1,517,150)	143,795		(453,946)	(18,845)		(1,176)					
12	Income Tax	Income Tax	Federal	2021	2,435,641		(6,954,225)	2,238,812		(6,757,396)		(8,317,550)	265,164		1,098,161					
13	Income Tax	Income Tax	KY	2021	(185,363)		(2,229,383)	(604,118)		(1,810,628)		(2,533,237)	30,450		273,404					

14	**Subtotal Income Tax**				2,250,278		(9,183,608)	1,634,694		(8,568,024)		(10,850,787)	295,614		1,371,565					
15	Franchise	Franchise Tax	KY	2021	1		(1)													
16	**Subtotal Franchise Tax**				1		(1)													
40	Total				18,784,698		11,313,917	19,166,294	(1,709,811)	9,222,510		4,991,320	4,952,208		1,370,389					

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Miscellaneous Current and Accrued Liabilities (Account 242)

1. Describe and report the amount of other current and accrued liabilities at the end of year.
2. Minor items (less than $250,000) may be grouped under appropriate title.

Line No.	Item (a)	Balance at End of Year (b)
1	Vacation Entitlment Reserve	1,551,133
2	Deferred Revenue PJM FTR	1,417,276
3	MISO MTEP - Short TermAccrual	879,924
4	Provision for Incentive Ben Prog	742,189
5	Retirement Bank Accrual	491,330
6	Wages Payable	389,000
7	FAS 158 Current Liabilities	318,633
8	Tax Reform	260,509
9	Native Deferred MTM Liability	107,188
10	Other Reserve/Accruals	11,494
11	Ratepayer Sharing Provisions	(224,857)
45	Total	5,943,819

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Other Deferred Credits (Account 253)

1. Report below the details called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (less than $250,000) may be grouped by classes.

Line No.	Description of Other Deferred Credits (a)	Balance at Beginning of Year (b)	Debit Contra Account (c)	Debit Amount (d)	Credits (e)	Balance at End of Year (f)
1	MISO MTEP Accrual	12,651,918			(555,393)	12,096,525
2	Deferred Revenue - Outdoor Lighting	1,123,168	415	141,398	125,220	1,106,990
3	Amort period 10 years over life of contracts					
4	MGP Reserve	668,331				668,331
5	FTR MTM gains/losses	158,441				158,441
6	Gas Refunds	20,789	805	64,701	193,978	150,066
7	Amort period varies					
8	SCHM Exec Cash Bal Plan				66,131	66,131
45	TOTAL	14,622,647		206,099	(170,064)	14,246,484

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Accumulated Deferred Income Taxes-Other Property (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject to accelerated amortization.
2. At Other (Specify), include deferrals relating to other income and deductions.
3. Provide in a footnote a summary of the type and amount of deferred income taxes reported in the beginning-of-year and end-of-year balances for deferred income taxes that the respondent estimates could be included in the development of jurisdictional recourse rates.

Line No.	Account Subdivisions (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)	Changes During Year Amounts Debited to Account 410.2 (e)	Changes During Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Account No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1	Account 282										
2	Electric	215,094,549	28,842,627	13,987,031	95,447	1,918,797		(374,146)			227,752,649
3	Gas	70,062,048	9,245,103	5,802,202	20,836					(684,048)	74,209,833
4	Other (Define)										
5	Total (Total of lines 2 thru 4)	285,156,597	38,087,730	19,789,233	116,283	1,918,797	—	(374,146)	—	(684,048)	301,962,482
6	Other (Specify)										
7	TOTAL Account 282 (Total of lines 5 thru 6)	285,156,597	38,087,730	19,789,233	116,283	1,918,797	—	(374,146)	—	(684,048)	301,962,482
8	Classification of TOTAL										
9	Federal Income Tax	235,515,406	29,498,685	15,754,286	93,104	1,536,310		(448,936)		(401,477)	247,769,140
10	State Income Tax	49,659,191	8,589,045	4,034,947	23,179	382,487		56,790		(282,571)	54,193,342
11	Local Income Tax										

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Accumulated Deferred Income Taxes-Other (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. At Other (Specify), include deferrals relating to other income and deductions.
3. Provide in a footnote a summary of the type and amount of deferred income taxes reported in the beginning-of-year and end-of-year balances for deferred income taxes that the respondent estimates could be included in the development of jurisdictional recourse rates.

Line No.	Account Subdivisions (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)	Changes During Year Amounts Debited to Account 410.2 (e)	Changes During Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Account No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1	Account 283										
2	Electric	25,373,878	13,122,033	6,863,624						352,881	31,279,406
3	Gas	5,071,383	530,934	301,866				138,440			5,438,891
4	Other (Define)										
5	Total (Total of lines 2 thru 4)	30,445,261	13,652,967	7,165,490				138,440		352,881	36,718,297
6	Other (Specify)										
7	TOTAL Account 283 (Total of lines 5 thru 6)	30,445,261	13,652,967	7,165,490				138,440		352,881	36,718,297
8	Classification of TOTAL										
9	Federal Income Tax	24,878,274	10,931,424	5,737,143				54,552	—	344,539	29,782,568
10	State Income Tax	5,566,987	2,721,543	1,428,347				83,888	—	8,342	6,935,729
11	Local Income Tax										

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Other Regulatory Liabilities (Account 254)

1. Report below the details called for concerning other regulatory liabilities which are created through the ratemaking actions of regulatory agencies (and not includable in other amounts).
2. For regulatory liabilities being amortized, show period of amortization in column (a).
3. Minor items (5% of the Balance at End of Year for Account 254 or amounts less than $250,000, whichever is less) may be grouped by classes.
4. Provide in a footnote, for each line item, the regulatory citation where the respondent was directed to refund the regulatory liability (e.g. Commission Order, state commission order, court decision).

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	Written off during Quarter/Period Account Credited (c)	Written off During Period Amount Refunded (d)	Written off During Period Amount Deemed Non-Refundable (e)	Credits (f)	Balance at End of Current Quarter/Year (g)
1	INCOME TAXES	130,062,605	190, 411			(6,180,409)	123,882,196
2	PENSION COSTS	6,041,411	182.3, 228.3, 254, 926			127,558	6,168,969
3	DSM ENERGY EFFICIENCY	1,003,631				(155,805)	847,826
4	–Order #2015-00368						
5	DEFERRED FORCED OUTAGE	1,887,187				(1,887,187)	
6	–Order #2017-00321						
45	Total	138,994,834				(8,095,843)	130,898,991

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Monthly Quantity & Revenue Data by Rate Schedule

1. Reference to account numbers in the USofA is provided in parentheses beside applicable data. Quantities must not be adjusted for discounts.
2. Total Quantities and Revenues in whole numbers.
3. Report revenues and quantities of gas by rate schedule. Where transportation services are bundled with storage services, reflect only transportation Dth. When reporting storage, report Dth of gas withdrawn from storage and revenues by rate schedule.
4. Revenues in Column (c) include transition costs from upstream pipelines. Revenue (Other) in Column (e) includes reservation charges received by the pipeline plus usage charges, less revenues reflected in Columns (c) and (d). Include in Column (e), revenue for Accounts 490-495.
5. Enter footnotes as appropriate.

Line No.	Item (a)	Month 1 Quantity (b)	Month 1 Revenue Costs and Take-or-Pay (c)	Month 1 Revenue (GRI & ACA) (d)	Month 1 Revenue (Other) (e)	Month 1 Revenue (Total) (f)	Month 2 Quantity (g)	Month 2 Revenue Costs and Take-or-Pay (h)	Month 2 Revenue (GRI & ACA) (i)	Month 2 Revenue (Other) (j)	Month 2 Revenue (Total) (k)	Month 3 Quantity (l)	Month 3 Revenue Costs and Take-or-Pay (m)	Month 3 Revenue (GRI & ACA) (n)	Month 3 Revenue (Other) (o)	Month 3 Revenue (Total) (p)
1	Total Sales (480-488)	310,421			5,001,544	5,001,544	1,034,461			11,872,098	11,872,098	1,444,096			19,542,630	19,542,630
2	Transportation of Gas for Others (489.2 and 489..3)															
3	Rate Case #PRO8-27				50,292	50,292				50,292	50,292				50,292	50,292
4	Rate FT	205,226			390,029	390,029	340,595			622,190	622,190	236,527			438,870	438,870
5	Rate IT	154,306			119,932	119,932	170,077			131,491	131,491	150,008			102,512	102,512
63	Total Transportation (Other than Gathering)	359,532	0	0	560,253	560,253	510,672	0	0	803,973	803,973	386,535	0	0	591,674	591,674
64	Storage (489.4)															
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90	Total Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
91	Gathering (489.1)															
92	Gathering-Firm															
93	Gathering-Interruptible															
94	Total Gathering (489.1)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
95	Additional Revenues															
96	Products Sales and Extraction (490-492)															
97	Rents (493-494)															
98	(495) Other Gas Revenues				(37)	(37)				(195)	(195)				1,870	1,870
99	(496) (Less) Provision for Rate Refunds															
100	Total Additional Revenues				(37)	(37)				(195)	(195)				1,870	1,870
101	Total Operating Revenues (Total of Lines 1,63,90,94 & 100)	669,953			5,561,760	5,561,760	1,545,133			12,675,876	12,675,876	1,830,631			20,136,174	20,136,174

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Gas Operating Revenues

1. Report below natural gas operating revenues for each prescribed account total. The amounts must be consistent with the detailed data on succeeding pages.
2. Revenues in columns (b) and (c) include transition costs from upstream pipelines.
3. Other Revenues in columns (f) and (g) include reservation charges received by the pipeline plus usage charges, less revenues reflected in columns (b) through (e). Include in columns (f) and (g) revenues for Accounts 480-495.
4. If increases or decreases from previous year are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. On Page 108, include information on major changes during the year, new service, and important rate increases or decreases.
6. Report the revenue from transportation services that are bundled with storage services as transportation service revenue.

Line No.	Title of Account (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transaction Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Previous Year (e)	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (i)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
1	(480) Residential Sales					75,307,862	65,909,529	75,307,862	65,909,529	6,197,994	6,161,372
2	(481) Commercial and Industrial Sales					31,006,607	24,177,328	31,006,607	24,177,328	3,700,623	3,354,877
3	(482) Other Sales to Public Authorities					1,155,817	1,468,306	1,155,817	1,468,306	128,165	224,696
4	(483) Sales for Resale										
5	(484) Interdepartmental Sales					27,338	22,783	27,338	22,783	4,309	4,182
6	(485) Intracompany Transfers										
7	(487) Forfeited Discounts						1,162		1,162		
8	(488) Miscellaneous Service Revenues					955,566	890,171	955,566	890,171		
9	(489.1) Revenues from Transportation of Gas of Others Through Gathering Facilities										
10	(489.2) Revenues from Transportation of Gas of Others Through Transmission Facilities					603,504	603,504	603,504	603,504		
11	(489.3) Revenues from Transportation of Gas of Others Through Distribution Facilities					6,503,904	5,646,249	6,503,904	5,646,249	4,384,120	4,292,468
12	(489.4) Revenues from Storing Gas of Others										
13	(490) Sales of Prod. Ext. from Natural Gas										
14	(491) Revenues from Natural Gas Proc. by Others										
15	(492) Incidental Gasoline and Oil Sales										
16	(493) Rent from Gas Property										
17	(494) Interdepartmental Rents										
18	(495) Other Gas Revenues					9,545	3,993	9,545	3,993		
19	Subtotal:					115,570,143	98,723,025	115,570,143	98,723,025		
20	(496) (Less) Provision for Rate Refunds					(50,142)	(50,142)	(50,142)	(50,142)		

21	TOTAL						115,620,285	98,773,167	115,620,285	98,773,167		

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Revenues from Transporation of Gas of Others Through Gathering Facilities (Account 489.1)

1. Report revenues and Dth of gas delivered through gathering facilities by zone of receipt (i.e. state in which gas enters respondent's system).
2. Revenues for penalties including penalties for unauthorized overruns must be reported on page 308.

Line No.	Rate Schedule and Zone of Receipt (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transaction Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Previous Year (e)	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (i)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
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Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Revenues from Transportation of Gas of Others Through Transmission Facilities (Account 489.2)

1. Report revenues and Dth of gas delivered by Zone of Delivery by Rate Schedule. Total by Zone of Delivery and for all zones. If respondent does not have separate zones, provide totals by rate schedule.
2. Revenues for penalties including penalties for unauthorized overruns must be reported on page 308.
3. Other Revenues in columns (f) and (g) include reservation charges received by the pipeline plus usage charges for transportation and hub services, less revenues reflected in columns (b) through (e).
4. Delivered Dth of gas must not be adjusted for discounting.
5. Each incremental rate schedule and each individually certificated rate schedule must be separately reported.
6. Where transportation services are bundled with storage services, report total revenues but only transportation Dth.

Line No.	Zone of Delivery, Rate Schedule (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transaction Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Previous Year (e)	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (i)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
1						603,504	603,504	603,504	603,504	8,579,821	11,294,195
40	Total					603,504	603,504	603,504	603,504		

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Revenues from Storing Gas of Others (Account 489.4)

1. Report revenues and Dth of gas withdrawn from storage by Rate Schedule and in total.
2. Revenues for penalties including penalties for unauthorized overruns must be reported on page 308.
3. Other revenues in columns (f) and (g) include reservation charges, deliverability charges, injection and withdrawal charges, less revenues reflected in columns (b) through (e).
4. Dth of gas withdrawn from storage must not be adjusted for discounting.
5. Where transportation services are bundled with storage services, report only Dth withdrawn from storage.

Line No.	Rate Schedule (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transaction Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Previous Year (e)	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (i)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
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Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Other Gas Revenues (Account 495)

Report below transactions of $250,000 or more included in Account 495, Other Gas Revenues. Group all transactions below $250,000 in one amount and provide the number of items.

Line No.	Description of Transaction (a)	Amount (in dollars) (b)
1	Commissions on Sale or Distribution of Gas of Others	
2	Compensation for Minor or Incidental Services Provided for Others	
3	Profit or Loss on Sale of Material and Supplies not Ordinarily Purchased for Resale	
4	Sales of Stream, Water, or Electricity, including Sales or Transfers to Other Departments	
5	Miscellaneous Royalties	
6	Revenues from Dehydration and Other Processing of Gas of Others except as provided for in the Instructions to Account 495	
7	Revenues for Right and/or Benefits Received from Others which are Realized Through Research, Development, and Demonstration Ventures	
8	Gains on Settlements of Imbalance Receivables and Payables	
9	Revenues from Penalties earned Pursuant to Tariff Provisions, including Penalties Associated with Cash-out Settlements	
10	Revenues from Shipper Supplied Gas	
11	Other revenues (Specify):	
12	Other revenues (Specify):	
13	Gas Losses Damaged Lines	9,545
40	TOTAL	9,545

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Discounted Rate Services and Negotiated Rate Services

1. In column b, report the revenues from discounted rate services.
2. In column c, report the volumes of discounted rate services.
3. In column d, report the revenues from negotiated rate services.
4. In column e, report the volumes of negotiated rate services.

Line No.	Account (a)	Discounted Rate Services Revenue (b)	Discounted Rate Services Volumes (c)	Negotiated Rate Services Revenue (d)	Negotiated Rate Services Volumes (e)
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2					
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37					
38					
39					
40	Total				

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Gas Operation and Maintenance Expenses

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. PRODUCTION EXPENSES		
2	A. Manufactured Gas Production		
3	Manufactured Gas Production (Submit Supplemental Statement)	[a]384,595	38,137
4	B. Natural Gas Production		
5	B1. Natural Gas Production and Gathering		
6	Operation		
7	750 Operation Supervision and Engineering		
8	751 Production Maps and Records		
9	752 Gas Well Expenses		
10	753 Field Lines Expenses		
11	754 Field Compressor Station Expenses		
12	755 Field Compressor Station Fuel and Power		
13	756 Field Measuring and Regulating Station Expenses		
14	757 Purification Expenses		
15	758 Gas Well Royalties		
16	759 Other Expenses		
17	760 Rents		
18	TOTAL Operation (Total of lines 7 thru 17)		
19	Maintenance		
20	761 Maintenance Supervision and Engineering		
21	762 Maintenance of Structures and Improvements		
22	763 Maintenance of Producing Gas Wells		
23	764 Maintenance of Field Lines		
24	765 Maintenance of Field Compressor Station Equipment		
25	766 Maintenance of Field Measuring and Regulating Station Equipment		
26	767 Maintenance of Purification Equipment		
27	768 Maintenance of Drilling and Cleaning Equipment		
28	769 Maintenance of Other Equipment		

29	TOTAL Maintenance (Total of lines 20 thru 28)		
30	TOTAL Natural Gas Production and Gathering (Total of lines 18 and 29)		
31	B2. Products Extraction		
32	Operation		
33	770 Operation Supervision and Engineering		
34	771 Operation Labor		
35	772 Gas Shrinkage		
36	773 Fuel		
37	774 Power		
38	775 Materials		
39	776 Operation Supplies and Expenses		
40	777 Gas Processed by Others		
41	778 Royalties on Products Extracted		
42	779 Marketing Expenses		
43	780 Products Purchased for Resale		
44	781 Variation in Products Inventory		
45	(Less) 782 Extracted Products Used by the Utility-Credit		
46	783 Rents		
47	TOTAL Operation (Total of lines 33 thru 46)		
48	Maintenance		
49	784 Maintenance Supervision and Engineering		
50	785 Maintenance of Structures and Improvements		
51	786 Maintenance of Extraction and Refining Equipment		
52	787 Maintenance of Pipe Lines		
53	788 Maintenance of Extracted Products Storage Equipment		
54	789 Maintenance of Compressor Equipment		
55	790 Maintenance of Gas Measuring and Regulating Equipment		
56	791 Maintenance of Other Equipment		
57	TOTAL Maintenance (Total of lines 49 thru 56)		
58	TOTAL Products Extraction (Total of lines 47 and 57)		
59	C. Exploration and Development		
60	Operation		
61	795 Delay Rentals		

62	796 Nonproductive Well Drilling		
63	797 Abandoned Leases		
64	798 Other Exploration		
65	TOTAL Exploration and Development (Total of lines 61 thru 64)		
66	D. Other Gas Supply Expenses		
67	Operation		
68	800 Natural Gas Well Head Purchases		
69	800.1 Natural Gas Well Head Purchases, Intracompany Transfers		
70	801 Natural Gas Field Line Purchases	48,470,949	29,344,830
71	802 Natural Gas Gasoline Plant Outlet Purchases		
72	803 Natural Gas Transmission Line Purchases		
73	804 Natural Gas City Gate Purchases		
74	804.1 Liquefied Natural Gas Purchases		
75	805 Other Gas Purchases	(6,018,898)	(2,714,385)
76	(Less) 805.1 Purchases Gas Cost Adjustments		
77	TOTAL Purchased Gas (Total of lines 68 thru 76)	42,452,051	26,630,445
78	806 Exchange Gas		
79	Purchased Gas Expenses		
80	807.1 Well Expense-Purchased Gas		
81	807.2 Operation of Purchased Gas Measuring Stations	224,812	226,267
82	807.3 Maintenance of Purchased Gas Measuring Stations	172,733	64,035
83	807.4 Purchased Gas Calculations Expenses		
84	807.5 Other Purchased Gas Expenses	217,734	225,035
85	TOTAL Purchased Gas Expenses (Total of lines 80 thru 84)	615,279	515,337
86	808.1 Gas Withdrawn from Storage-Debit		
87	(Less) 808.2 Gas Delivered to Storage-Credit		
88	809.1 Withdrawals of Liquefied Natural Gas for Processing-Debit		
89	(Less) 809.2 Deliveries of Natural Gas for Processing-Credit		
90	Gas used in Utility Operation-Credit		
91	810 Gas Used for Compressor Station Fuel-Credit		
92	811 Gas Used for Products Extraction-Credit		
93	812 Gas Used for Other Utility Operations-Credit		
94	TOTAL Gas Used in Utility Operations-Credit (Total of lines 91 thru 93)		

95	813 Other Gas Supply Expenses		
96	TOTAL Other Gas Supply Exp. (Total of lines 77,78,85,86 thru 89,94,95)	43,067,330	27,145,782
97	TOTAL Production Expenses (Total of lines 3, 30, 58, 65, and 96)	43,451,925	27,183,919
98	2. NATURAL GAS STORAGE, TERMINALING AND PROCESSING EXPENSES		
99	A. Underground Storage Expenses		
100	Operation		
101	814 Operation Supervision and Engineering		
102	815 Maps and Records		
103	816 Wells Expenses		
104	817 Lines Expense		
105	818 Compressor Station Expenses		
106	819 Compressor Station Fuel and Power		
107	820 Measuring and Regulating Station Expenses		
108	821 Purification Expenses		
109	822 Exploration and Development		
110	823 Gas Losses		
111	824 Other Expenses		
112	825 Storage Well Royalties		
113	826 Rents		
114	TOTAL Operation (Total of lines of 101 thru 113)		
115	Maintenance		
116	830 Maintenance Supervision and Engineering		
117	831 Maintenance of Structures and Improvements		
118	832 Maintenance of Reservoirs and Wells		
119	833 Maintenance of Lines		
120	834 Maintenance of Compressor Station Equipment		
121	835 Maintenance of Measuring and Regulating Station Equipment		
122	836 Maintenance of Purification Equipment		
123	837 Maintenance of Other Equipment		
124	TOTAL Maintenance (Total of lines 116 thru 123)		
125	TOTAL Underground Storage Expenses (Total of lines 114 and 124)		
126	B. Other Storage Expenses		
127	Operation		

128	840 Operation Supervision and Engineering		
129	841 Operation Labor and Expenses		
130	842 Rents		
131	842.1 Fuel		
132	842.2 Power		
133	842.3 Gas Losses		
134	TOTAL Operation (Total of lines 128 thru 133)		
135	Maintenance		
136	843.1 Maintenance Supervision and Engineering		
137	843.2 Maintenance of Structures		
138	843.3 Maintenance of Gas Holders		
139	843.4 Maintenance of Purification Equipment		
140	843.5 Maintenance of Liquefaction Equipment		
141	843.6 Maintenance of Vaporizing Equipment		
142	843.7 Maintenance of Compressor Equipment		
143	843.8 Maintenance of Measuring and Regulating Equipment		
144	843.9 Maintenance of Other Equipment		
145	TOTAL Maintenance (Total of lines 136 thru 144)		
146	TOTAL Other Storage Expenses (Total of lines 134 and 145)		
147	C. Liquefied Natural Gas Terminaling and Processing Expenses		
148	Operation		
149	844.1 Operation Supervision and Engineering		
150	844.2 LNG Processing Terminal Labor and Expenses		
151	844.3 Liquefaction Processing Labor and Expenses		
152	844.4 Liquefaction Transportation Labor and Expenses		
153	844.5 Measuring and Regulating Labor and Expenses		
154	844.6 Compressor Station Labor and Expenses		
155	844.7 Communication System Expenses		
156	844.8 System Control and Load Dispatching		
157	845.1 Fuel		
158	845.2 Power		
159	845.3 Rents		
160	845.4 Demurrage Charges		

161	(less) 845.5 Wharfage Receipts-Credit		
162	845.6 Processing Liquefied or Vaporized Gas by Others		
163	846.1 Gas Losses		
164	846.2 Other Expenses		
165	TOTAL Operation (Total of lines 149 thru 164)		
166	Maintenance		
167	847.1 Maintenance Supervision and Engineering		
168	847.2 Maintenance of Structures and Improvements		
169	847.3 Maintenance of LNG Processing Terminal Equipment		
170	847.4 Maintenance of LNG Transportation Equipment		
171	847.5 Maintenance of Measuring and Regulating Equipment		
172	847.6 Maintenance of Compressor Station Equipment		
173	847.7 Maintenance of Communication Equipment		
174	847.8 Maintenance of Other Equipment		
175	TOTAL Maintenance (Total of lines 167 thru 174)		
176	TOTAL Liquefied Nat Gas Terminaling and Proc Exp (Total of lines 165 and 175)		
177	TOTAL Natural Gas Storage (Total of lines 125, 146, and 176)		
178	3. TRANSMISSION EXPENSES		
179	Operation		
180	850 Operation Supervision and Engineering	3,103	3,067
181	851 System Control and Load Dispatching		
182	852 Communication System Expenses		
183	853 Compressor Station Labor and Expenses		
184	854 Gas for Compressor Station Fuel		
185	855 Other Fuel and Power for Compressor Stations		
186	856 Mains Expenses		
187	857 Measuring and Regulating Station Expenses		
188	858 Transmission and Compression of Gas by Others		
189	859 Other Expenses	49,819	12,585
190	860 Rents		
191	TOTAL Operation (Total of lines 180 thru 190)	52,922	15,652
192	Maintenance		
193	861 Maintenance Supervision and Engineering		

194	862 Maintenance of Structures and Improvements		
195	863 Maintenance of Mains	113,925	188,034
196	864 Maintenance of Compressor Station Equipment		
197	865 Maintenance of Measuring and Regulating Station Equipment		
198	866 Maintenance of Communication Equipment		
199	867 Maintenance of Other Equipment		
200	TOTAL Maintenance (Total of lines 193 thru 199)	113,925	188,034
201	TOTAL Transmission Expenses (Total of lines 191 and 200)	166,847	203,686
202	4. DISTRIBUTION EXPENSES		
203	Operation		
204	870 Operation Supervision and Engineering		
205	871 Distribution Load Dispatching	241,636	224,466
206	872 Compressor Station Labor and Expenses		
207	873 Compressor Station Fuel and Power		
208	874 Mains and Services Expenses	1,502,997	1,680,494
209	875 Measuring and Regulating Station Expenses-General	160,551	135,707
210	876 Measuring and Regulating Station Expenses-Industrial	33,423	16,898
211	877 Measuring and Regulating Station Expenses-City Gas Check Station		
212	878 Meter and House Regulator Expenses	736,367	1,345,018
213	879 Customer Installations Expenses	1,090,134	1,471,953
214	880 Other Expenses	2,102,473	1,736,165
215	881 Rents		
216	TOTAL Operation (Total of lines 204 thru 215)	5,867,581	6,610,701
217	Maintenance		
218	885 Maintenance Supervision and Engineering		
219	886 Maintenance of Structures and Improvements		
220	887 Maintenance of Mains	862,405	892,976
221	888 Maintenance of Compressor Station Equipment		
222	889 Maintenance of Measuring and Regulating Station Equipment-General	101,103	51,632
223	890 Maintenance of Meas. and Reg. Station Equipment-Industrial		959
224	891 Maintenance of Meas. and Reg. Station Equip-City Gate Check Station		
225	892 Maintenance of Services	730,412	676,783
226	893 Maintenance of Meters and House Regulators	109,242	207,313

227	894 Maintenance of Other Equipment	119,353	208,655
228	TOTAL Maintenance (Total of lines 218 thru 227)	1,922,515	2,038,318
229	TOTAL Distribution Expenses (Total of lines 216 and 228)	7,790,096	8,649,019
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	189,162	199,855
233	902 Meter Reading Expenses	17,187	19,162
234	903 Customer Records and Collection Expenses	3,129,965	2,706,163
235	904 Uncollectible Accounts		6,856
236	905 Miscellaneous Customer Accounts Expenses	80	188
237	TOTAL Customer Accounts Expenses (Total of lines 232 thru 236)	3,336,394	2,932,224
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision		
241	908 Customer Assistance Expenses	136,980	106,450
242	909 Informational and Instructional Expenses	2,938	1,734
243	910 Miscellaneous Customer Service and Informational Expenses	195,424	178,182
244	TOTAL Customer Service and Information Expenses (Total of lines 240 thru 243)	335,342	286,366
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision		
248	912 Demonstrating and Selling Expenses	336,170	243,895
249	913 Advertising Expenses	948	2,601
250	916 Miscellaneous Sales Expenses		
251	TOTAL Sales Expenses (Total of lines 247 thru 250)	337,118	246,496
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	3,041,154	2,255,247
255	921 Office Supplies and Expenses	1,509,532	1,414,566
256	(Less) 922 Administrative Expenses Transferred-Credit	1	
257	923 Outside Services Employed	870,090	2,580,019
258	924 Property Insurance	67,422	56,824
259	925 Injuries and Damages	172,790	108,902

260	926 Employee Pensions and Benefits	1,770,804	2,162,301
261	927 Franchise Requirements		
262	928 Regulatory Commission Expenses	244,627	252,903
263	(Less) 929 Duplicate Charges-Credit	271,287	159,496
264	930.1General Advertising Expenses	17,497	17,120
265	930.2Miscellaneous General Expenses	109,488	589,609
266	931 Rents	373,797	355,510
267	TOTAL Operation (Total of lines 254 thru 266)	7,905,913	9,633,505
268	Maintenance		
269	932 Maintenance of General Plant	18,851	(328,306)
270	TOTAL Administrative and General Expenses (Total of lines 267 and 269)	7,924,764	9,305,199
271	TOTAL Gas O&M Expenses (Total of lines 97,177,201,229,237,244,251, and 270)	63,342,486	48,806,909

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: ManufacturedGasProduction

	Q4 2021	Q4 2020
Gas Boiler Labor	3,597	4,185
Other Power Expenses	5,067	2,668
Liquified Petroleum Gas Expense	103,506	129,707
Liquified Petroleum Gas	144,379	(205,124)
Misc. Production Expense	95,964	89,529
Gas Raw Material - Rents	0	0
Total Operation:	**352,513**	**20,965**
Production Equipment	32,082	17,172
Total Maintenance:	**32,082**	**17,172**
Total Manufactured Gas Production:	**384,595**	**38,137**

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Exchange and Imbalance Transactions

1. Report below details by zone and rate schedule concerning the gas quantities and related dollar amount of imbalances associated with system balancing and no-notice service. Also, report certificated natural gas exchange transactions during the year. Provide subtotals for imbalance and no-notice quantities for exchanges. If respondent does not have separate zones, provide totals by rate schedule. Minor exchange transactions (less than 100,000 Dth) may be grouped.

Line No.	Zone/Rate Schedule (a)	Gas Received from Others Amount (b)	Gas Received from Others Dth (c)	Gas Delivered to Others Amount (d)	Gas Delivered to Others Dth (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
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16					
17					
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19					
20					
21					
22					
23					
24					
25	Total				

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Gas Used in Utility Operations

1. Report below details of credits during the year to Accounts 810, 811, and 812.
2. If any natural gas was used by the respondent for which a charge was not made to the appropriate operating expense or other account, list separately in column (c) the Dth of gas used, omitting entries in column (d).

Line No.	Purpose for Which Gas Was Used (a)	Account Charged (b)	Natural Gas Gas Used Dth (c)	Natural Gas Amount of Credit (in dollars) (d)
1	810 Gas Used for Compressor Station Fuel - Credit			
2	811 Gas Used for Products Extraction - Credit			
3	Gas Shrinkage and Other Usage in Respondent's Own Processing - Credit			
4	Gas Shrinkage, etc. for Respondent's Gas Processed by Others - Credit			
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6				
7				
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11				
12				
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17				
18				
19				
20				
21				
22				
23				
24				
25	Total			

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Transmission and Compression of Gas by Others (Account 858)

1. Report below details concerning gas transported or compressed for respondent by others equaling more than 1,000,000 Dth and amounts of payments for such services during the year. Minor items (less than 1,000,000) Dth may be grouped. Also, include in column (c) amounts paid as transition costs to an upstream pipeline.
2. In column (a) give name of companies, points of delivery and receipt of gas. Designate points of delivery and receipt so that they can be identified readily on a map of respondent's pipeline system.
3. Designate associated companies with an asterisk in column (b).

Line No.	Name of Company and Description of Service Performed (a)	* (b)	Amount of Payment (c)	Dth of Gas Delivered (d)
1				
2				
3				
4				
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16				
17				
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19				
20				
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22				
23				
24				
25	Total			

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Other Gas Supply Expenses (Account 813)

1. Report other gas supply expenses by descriptive titles that clearly indicate the nature of such expenses. Show maintenance expenses, revaluation of monthly encroachments recorded in Account 117.4, and losses on settlements of imbalances and gas losses not associated with storage separately. Indicate the functional classification and purpose of property to which any expenses relate. List separately items of $250,000 or more.

Line No.	Description (a)	Amount (in dollars) (b)
1		
2		
3		
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19		
20		
21		
22		
23		
24		
25	Total	

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Miscellaneous General Expenses (Account 930.2)

1. Provide the information requested below on miscellaneous general expenses.
2. For Other Expenses, show the (a) purpose, (b) recipient and (c) amount of such items. List separately amounts of $250,000 or more however, amounts less than $250,000 may be grouped if the number of items of so grouped is shown.

Line No.	Description (a)	Amount (b)
1	Industry association dues.	
2	Experimental and general research expenses	
2a	a. Gas Research Institute (GRI)	
2b	b. Other	42
3	Publishing and distributing information and reports to stockholders, trustee, registrar, and transfer agent fees and expenses, and other expenses of servicing outstanding securities of the respondent	
4	Other expenses	
5	Business and Service Company Support	56,254
6	Dues and Subscriptions to Various Organizations	39,081
7	Director's Fees and Expenses	16,717
8	Shareholder's Communication/Systems	1,626
9	Account Analysis Reconciliation Adjustments	(4,232)
25	TOTAL	109,488

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Depreciation, Depletion and Amortization of Gas Plant (Accts 403, 404.1, 404.2, 404.3, 405) (Except Amortization of Acquisition Adjustments)

1. Report in Section A the amounts of depreciation expense, depletion and amortization for the accounts indicated and classified according to the plant functional groups shown.
2. Report in Section B, column (b) all depreciable or amortizable plant balances to which rates are applied and show a composite total. (If more desirable, report by plant account, subaccount or functional classifications other than those pre-printed in column (a). Indicate in a footnote the manner in which column (b) balances are obtained. If average balances are used, state the method of averaging used. For column (c) report available information for each plant functional classification listed in column (a). If composite depreciation accounting is used, report available information called for in columns (b) and (c) on this basis. Where the unit-of-production method is used to determine depreciation charges, show in a footnote any revisions made to estimated gas reserves.
3. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state in a footnote the amounts and nature of the provisions and the plant items to which related.
4. Add rows as necessary to completely report all data. Number the additional rows in sequence as 2.01, 2.02, 3.01, 3.02, etc.

Section A. Summary of Depreciation, Depletion, and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization and Depletion of Producing Natural Gas Land and Land Rights (Account 404.1) (d)	Amortization of Underground Storage Land and Land Rights (Account 404.2) (e)	Amortization of Other Limited-term Gas Plant (Account 404.3) (f)	Amortization of Other Gas Plant (Account 405) (g)	Total (b to g) (h)
1	Intangible plant					3,249,511		3,249,511
2	Production plant, manufactured gas	1,106,895						1,106,895
3	Production and Gathering Plant							
4	Products extraction plant							
5	Underground Gas Storage Plant (footnote details)							
6	Other storage plant							
7	Base load LNG terminaling and processing plant							
8	Transmission Plant							
9	Distribution plant	14,817,863						14,817,863
10	General Plant (footnote details)	70,825				1,069,535		1,140,360
11	Common plant-gas	(17,818)						(17,818)
12	Total	15,977,765				4,319,046		20,296,811

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Depreciation, Depletion and Amortization of Gas Plant (Accts 403, 404.1, 404.2, 404.3, 405) (Except Amortization of Acquisition Adjustments)

1. Report in Section A the amounts of depreciation expense, depletion and amortization for the accounts indicated and classified according to the plant functional groups shown.
2. Report in Section B, column (b) all depreciable or amortizable plant balances to which rates are applied and show a composite total. (If more desirable, report by plant account, subaccount or functional classifications other than those pre-printed in column (a). Indicate in a footnote the manner in which column (b) balances are obtained. If average balances are used, state the method of averaging used. For column (c) report available information for each plant functional classification listed in column (a). If composite depreciation accounting is used, report available information called for in columns (b) and (c) on this basis. Where the unit-of-production method is used to determine depreciation charges, show in a footnote any revisions made to estimated gas reserves.
3. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state in a footnote the amounts and nature of the provisions and the plant items to which related.
4. Add rows as necessary to completely report all data. Number the additional rows in sequence as 2.01, 2.02, 3.01, 3.02, etc.

Section B. Factors Used in Estimating Depreciation Charges

Line No.	Functional Classification (a)	Plant Bases (in thousands) (b)	Applied Depreciation or Amortization Rates (percent) (c)
1	Production and Gathering Plant		
2	Offshore (footnote details)		
3	Onshore (footnote details)		
4	Underground Gas Storage Plant (footnote details)		
5	Transmission Plant		
6	Offshore (footnote details)		
7	Onshore (footnote details)		
8	General Plant (footnote details)	[a]14,110	7.29%
9	Distribution Plant	745,710	2.24%
10	Other Storage Plant		
11	Intangible Plant	5,663	[b]0%
12	Gas - Manufactured Production Plant	14,708	7.9%

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FOOTNOTE DATA

(a) Concept: PlantBasesUsedInEstimatingDepreciationCharges
Depreciable Plant Base represents balances as of December 31, 2021, and excludes plant related to Land and Asset Retirement Obligations.
(b) Concept: AppliedDepreciationOrAmortizationRates
Intangible plant is amortized over 3, 5, and 10 years.

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Particulars Concerning Certain Income Deductions and Interest Charges Accounts

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts.

a. Miscellaneous Amortization (Account 425)-Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.
b. Miscellaneous Income Deductions-Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than $250,000 may be grouped by classes within the above accounts.
c. Interest on Debt to Associated Companies (Account 430)-For each associated company that incurred interest on debt during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.
d. Other Interest Expense (Account 431) - Report details including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)	Amount (b)
1	Account 425 - Miscellaneous Amortization	
2		
3		
4		
5	TOTAL Account 425 - Miscellaneous Amortization	
6	Account 426.1 - Donations	
7	Customer Assistance Programs	139,402
8	Items Under Threshold	274,585
9	TOTAL Account 426.1 - Donations	413,987
10	Account 426.2 - Life Insurance	
11	Life Insurance Expense	(9,857)
12	TOTAL Account 426.2 - Life Insurance	(9,857)
13	Account 426.3 - Penalties	
14	Settlement Agreement	166,667
15	Items Under Threshold	
16	TOTAL Account 426.3 - Penalties	166,667
17	Account 426.4 Expenditures for Certain Civic, Political, and Related Activities	
18	Civil, Political & Related Activities	454,776
19	Total Account 426.4 - Expendituees for Certain Civic, Political, and Related Activities	454,776
20	Account 426.5 - Other Deductions	
21	Sale of A/R Fees	1,542,313
22	PPE Impairment	2,271,499
23	Items Under Treshold	3,265

24	TOTAL Account 426.5 - Other Deductions	3,817,077
25	Account 430 - Interest on Debt to Associated Companies	
26	Money Pool - Duke Energy Kentucky to Duke Energy Corporation	135,836
27	Money Pool - Duke Energy Kentucky to Duke Energy Florida	151
28	Money Pool - Duke Energy Kentucky to Duke Energy Indiana	2,176
29	Money Pool - Duke Energy Kentucky to Duke Energy Ohio	97
30	Money Pool - Duke Energy Kentucky to Duke Energy Progress	1,181
31	Money Pool - Duke Energy Kentucky to Duke Energy Carolinas	1,188
32	Money Pool - Duke Energy Kentucky to Piedmont Natural Gas	915
33	Money Pool - Items Under Threshold	(91)
34	TOTAL Account 430 - Interest on Debt to Associated Companies	141,453
35	Account 431 - Other Interest Expense	
36	Swap Net Interest	1,012,830
37	Credit Facility	560,771
38	Interest - Assigned from Service Company	31,046
39	Customer Service Deposits	10,766
40	Deferred Compensation for Board of Directors	1,561
41	Coal Ash Equity Return	(250,697)
42	Items Under Treshold	2
43	TOTAL Account 431 - Other Interest Expense	1,366,279

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Regulatory Commission Expenses (Account 928)

1. Report below details of regulatory commission expenses incurred during the current year (or in previous years, if being amortized) relating to formal cases before a regulatory body, or cases in which such a body was a party.
2. In column (b) and (c), indicate whether the expenses were assessed by a regulatory body or were otherwise incurred by the utility.
3. Show in column (k) any expenses incurred in prior years that are being amortized. List in column (a) the period of amortization.
4. Identify separately all annual charge adjustments (ACA).
5. List in column (f), (g), and (h) expenses incurred during year which were charges currently to income, plant, or other accounts.
6. Minor items (less than $250,000) may be grouped.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses to Date (d)	Deferred in Account 182.3 at Beginning of Year (e)	Expenses Incurred During Year Charged Currently To Department (f)	Expenses Incurred During Year Charged Currently To Account No. (g)	Expenses Incurred During Year Charged Currently To Amount (h)	Expenses Incurred During Year Deferred to Account 182.3 (i)	Amortized During Year Contra Account (j)	Amortized During Year Amount (k)	Deferred in Account 182.3 End of Year (l)
1	Kentucky Public Service Commission											
2	Gas Related	193,649		193,649		Gas	928	193,649				
3	Electric Related	686,710		686,710		Electric	928	686,710				
4	Request for Rate Increase - Electric Case No. 2017-00321		85,465	85,465	341,859	Electric				928	85,465	256,394
5	Request for Rate Increase - Gas Case No. 2018-00261		51,031	51,031	165,852	Gas				928	51,031	114,821
6	Request for Rate Increase - Electric Case No. 2019-00271		67,834	67,834	293,946	Electric				928	67,834	226,112
7	Request for Rate Increase - Gas Case No. 2021-0190								145,138			145,138
8	Other Minor Items											
9	Items reclassed in 2021 - Gas		(53)	(53)		Gas	928	(53)				
10	Items reclassed in 2021 - Electric		(143)	(143)		Electric	928	(143)				
25	TOTAL	880,359	204,134	1,084,493	801,657			880,163	145,138		204,330	742,465

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Employee Pensions and Benefits (Account 926)

1. Report below the items contained in Account 926, Employee Pensions and Benefits.

Line No.	Expense (a)	Amount (in dollars) (b)
1	Pensions - defined benefit plans	(116,489)
2	Pensions - other	387,887
3	Post-retirement benefits other than pensions (PBOP)	26,348
4	Post-employment benefit plans	(69,630)
5	Other (Specify)	
6	Medical and Dental	545,384
7	Life Insurance	6,750
8	Service/Safety Awards	4,497
9	Other Work/Family Benefits/Tuition	4,306
10	Allocated S&E	22
11	Benefits Distribution	989,185
12	Other	(7,456)
40	Total	1,770,804

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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. Salaries and wages billed to the Respondent by an affiliated company must be assigned to the particular operating function(s) relating to the expenses.

In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used. When reporting detail of other accounts, enter as many rows as necessary numbered sequentially starting with 75.01, 75.02, etc.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Payroll Billed by Affiliated Companies (c)	Allocation of Payroll Charged for Clearing Accounts (d)	Total (e)
1	Electric				
2	Operation				
3	Production	5,127,098	3,001,419	291,370	8,419,887
4	Transmission	6,660	509,530	18,503	534,693
5	Distribution	537,373	924,120	52,388	1,513,881
6	Customer Accounts	154,708	1,782,243	69,431	2,006,382
7	Customer Service and Informational		76,658	2,748	79,406
8	Sales				
9	Administrative and General	1,348,338	7,322,027	310,793	8,981,158
10	TOTAL Operation (Total of lines 3 thru 9)	7,174,177	13,615,997	745,233	21,535,407
11	Maintenance				
12	Production	1,721,257	3,048,567		4,769,824
13	Transmission	31,092	218,073		249,165
14	Distribution	696,121	833,972		1,530,093
15	Administrative and General				
16	TOTAL Maintenance (Total of lines 12 thru 15)	2,448,470	4,100,612		6,549,082
17	Total Operation and Maintenance				
18	Production (Total of lines 3 and 12)	6,848,355	6,049,986	291,370	13,189,711
19	Transmission (Total of lines 4 and 13)	37,752	727,603	18,503	783,858
20	Distribution (Total of lines 5 and 14)	1,233,494	1,758,092	52,388	3,043,974
21	Customer Accounts (line 6)	154,708	1,782,243	69,431	2,006,382
22	Customer Service and Informational (line 7)		76,658	2,748	79,406
23	Sales (line 8)				
24	Administrative and General (Total of lines 9 and 15)	1,348,338	7,322,027	310,793	8,981,158

25	TOTAL Operation and Maintenance (Total of lines 18 thru 24)	9,622,647	17,716,609	745,233	28,084,489
26	Gas				
27	Operation				
28	Production - Manufactured Gas	132,520	37,763	287	170,570
29	Production - Natural Gas(Including Exploration and Development)				
30	Other Gas Supply		364,583	616	365,199
31	Storage, LNG Terminaling and Processing				
32	Transmission				
33	Distribution	1,559,924	1,246,327	4,738	2,810,989
34	Customer Accounts	71,469	1,187,214	2,125	1,260,808
35	Customer Service and Informational		134,234	227	134,461
36	Sales				
37	Administrative and General	489,702	1,952,455	4,123	2,446,280
38	TOTAL Operation (Total of lines 28 thru 37)	2,253,615	4,922,576	12,116	7,188,307
39	Maintenance				
40	Production - Manufactured Gas	12,332	9,509		21,841
41	Production - Natural Gas(Including Exploration and Development)				
42	Other Gas Supply				
43	Storage, LNG Terminaling and Processing				
44	Transmission				
45	Distribution	338,210	422,838		761,048
46	Administrative and General	5,247	611		5,858
47	TOTAL Maintenance (Total of lines 40 thru 46)	355,789	432,958		788,747
49	Total Operation and Maintenance				
50	Production - Manufactured Gas (Total of lines 28 and 40)	144,852	47,272	287	192,411
51	Production - Natural Gas (Including Expl. and Dev.)(ll. 29 and 41)				
52	Other Gas Supply (Total of lines 30 and 42)		364,583	616	365,199
53	Storage, LNG Terminaling and Processing (Total of ll. 31 and 43)				
54	Transmission (Total of lines 32 and 44)				
55	Distribution (Total of lines 33 and 45)	1,898,134	1,669,165	4,738	3,572,037
56	Customer Accounts (Total of line 34)	71,469	1,187,214	2,125	1,260,808
57	Customer Service and Informational (Total of line 35)		134,234	227	134,461
58	Sales (Total of line 36)				

59	Administrative and General (Total of lines 37 and 46)	494,949	1,953,066	4,123	2,452,138
60	Total Operation and Maintenance (Total of lines 50 thru 59)	2,609,404	5,355,534	12,116	7,977,054
61	Other Utility Departments				
62	Operation and Maintenance				
63	TOTAL ALL Utility Dept. (Total of lines 25, 60, and 62)	12,232,051	23,072,143	757,349	36,061,543
64	Utility Plant				
65	Construction (By Utility Departments)				
66	Electric Plant	7,227,627	9,027,302	557,621	16,812,550
67	Gas Plant	1,612,927	5,673,431	305,080	7,591,438
68	Other				
69	TOTAL Construction (Total of lines 66 thru 68)	8,840,554	14,700,733	862,701	24,403,988
70	Plant Removal (By Utility Departments)				
71	Electric Plant	1,067,171	1,139,321		2,206,492
72	Gas Plant	195,276	313,697		508,973
73	Other				
74	TOTAL Plant Removal (Total of lines 71 thru 73)	1,262,447	1,453,018		2,715,465
75.1	Other Accounts (Specify)				
75.2	Projects For Duke's Subsidiaries & Merchandising		31,667		31,667
75.3	Other Work in Progress	(2,550,990)	2,783,565		232,575
75.4	Other Accounts	96,480	1,143,494		1,239,974
76	TOTAL Other Accounts	(2,454,510)	3,958,726		1,504,216
77	TOTAL SALARIES AND WAGES	19,880,542	43,184,620	1,620,050	64,685,212

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Charges for Outside Professional and Other Consultative Services

1. Report the information specified below for all charges made during the year included in any account (including plant accounts) for outside consultative and other professional services. These services include rate, management, construction, engineering, research, financial, valuation, legal, accounting, purchasing, advertising, labor relations, and public relations, rendered for the respondent under written or oral arrangement, for which aggregate payments were made during the year to any corporation partnership, organization of any kind, or individual (other than for services as an employee or for payments made for medical and related services) amounting to more than $250,000, including payments for legislative services, except those which should be reported in Account 426.4 Expenditures for Certain Civic, Political and Related Activities. (a) Name of person or organization rendering services. (b) Total charges for the year.
2. Sum under a description "Other", all of the aforementioned services amounting to $250,000 or less.
3. Total under a description "Total", the total of all of the aforementioned services.
4. Charges for outside professional and other consultative services provided by associated (affiliated) companies should be excluded from this schedule and be reported on Page 358, according to the instructions for that schedule.

Line No.	Description (a)	Amount (in dollars) (b)
1	M&M SERVICES CO INC - Consulting - Construction	791,341
2	EMERSON PROCESS MANAGEMENT POWER & WATER - Consultant - Engineering	597,258
3	SARGENT & LUNDY LLC - Consulting - Engineering	529,450
4	Other	1,711,380
5	Total	3,629,429
6	TOTAL	

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Transactions with Associated (Affiliated) Companies

1. Report below the information called for concerning all goods or services received from or provided to associated (affiliated) companies amounting to more than $250,000.
2. Sum under a description "Other", all of the aforementioned goods and services amounting to $250,000 or less.
3. Total under a description "Total", the total of all of the aforementioned goods and services.
4. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote the basis of the allocation.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	Goods or Services Provided by Affiliated Company			
2	[a] Services Provided by Duke Energy Business Services	Duke Energy Business Services LLC	Various	163,672,601
3	Customer & Market Services	Duke Energy Carolinas, LLC	Various	4,985,638
4	Generation Services	Duke Energy Carolinas, LLC	Various	940,263
5	Other Goods and Services	Duke Energy Carolinas, LLC	Various	1,550,844
6	Transmission and Distribution Services	Duke Energy Carolinas, LLC	Various	1,436,540
7	Customer & Market Services	Duke Energy Progress, LLC	Various	173,659
8	Generation Services	Duke Energy Progress, LLC	Various	811,070
9	Other Goods and Services	Duke Energy Progress, LLC	Various	219,202
10	Transmission and Distribution Services	Duke Energy Progress, LLC	Various	108,561
11	Customer & Market Services	Duke Energy Florida LLC	Various	88,670
12	Generation Services	Duke Energy Florida LLC	Various	70,279
13	Other Goods and Services	Duke Energy Florida LLC	Various	162,652
14	Transmission and Distribution Services	Duke Energy Florida LLC	Various	19,356
15	Customer & Market Services	Duke Energy Indiana, LLC	Various	191,608
16	Generation Services	Duke Energy Indiana, LLC	Various	6,066,143
17	Other Goods and Services	Duke Energy Indiana, LLC	Various	1,829,057
18	Transmission and Distribution Services	Duke Energy Indiana, LLC	Various	83,049
19	Customer & Market Services	Duke Energy Ohio, LLC	Various	2,788,635
20	Gas Distribution Services	Duke Energy Ohio, LLC	Various	3,370,134
21	Other Goods and Services	Duke Energy Ohio, LLC	Various	
22	Transmission and Distribution Services	Duke Energy Ohio, LLC	Various	5,603,957
23	Gas Distribution Services	Piedmont Natural Gas Company Inc	Various	3,941,534
24	Other Goods and Services	Duke Energy Commercial Enterprises	Various	18,985
25	Gas Distribution Services	Duke Energy Carolinas, LLC	Various	

26	Other Goods and Services	Duke Energy Carolinas, LLC	Various	
27	Gas Distribution Services	Duke Energy Progress, LLC	Various	
28	Gas Distribution Services	Duke Energy Indiana, LLC	Various	
29	Generation Services	Duke Energy Ohio, Inc	Various	
19	TOTAL			
20	Goods or Services Provided for Affiliated Company			
21	Other Goods and Services	Duke Energy Ohio, LLC	Various	
22	Customer and Market Services	Duke Energy Carolinas, LLC	Various	67
23	Gas Distribution Services	Duke Energy Carolinas, LLC	Various	
24	Generation Services	Duke Energy Carolinas, LLC	Various	9,374
25	Other Goods and Services	Duke Energy Carolinas, LLC	Various	
26	Transmission and Distribution Services	Duke Energy Carolinas, LLC	Various	102,355
27	Customer and Market Services	Duke Energy Progress, LLC	Various	28
28	Gas Distribution Services	Duke Energy Progress, LLC	Various	
29	Generation Services	Duke Energy Progress, LLC	Various	3,785
30	Transmission and Distribution Services	Duke Energy Progress, LLC	Various	2,012
31	Customer and Market Services	Duke Energy Florida, LLC	Various	33
32	Generation Services	Duke Energy Florida, LLC	Various	1,133
33	Other Goods and Services	Duke Energy Florida, LLC	Various	1,260
34	Transmission and Distribution Services	Duke Energy Florida, LLC	Various	5,289
35	Transmission and Distribution Services	Duke Energy Business Services LLC	Various	1,439
36	Customer and Market Services	Duke Energy Indiana, LLC	Various	15
37	Gas Distribution Services	Duke Energy Indiana, LLC	Various	
38	Generation Services	Duke Energy Indiana, LLC	Various	1,055,348
39	Transmission and Distribution Services	Duke Energy Indiana, LLC	Various	240,273
40	Customer & Market Services	Duke Energy Ohio, Inc	Various	73,056
41	Gas Distribution Services	Duke Energy Ohio, Inc	Various	978,399
42	Other Goods and Services	Duke Energy Ohio, Inc	Various	179,000
43	Transmission and Distribution Services	Duke Energy Ohio, Inc	Various	1,301,182
44	Generation Services	Duke Energy Ohio, Inc	Various	
45	Gas Distribution Services	KO Transmission Company	Various	(9,345)
46	Customer and Market Services	Piedmont Natural Gas Company, Inc.	Various	49
47	Gas Distribution Services	Piedmont Natural Gas Company, Inc.	Various	2,433
40	TOTAL			

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FOOTNOTE DATA

(a) Concept: DescriptionOfTheGoodOrService

When an employee of the Service Company performs services for a Client Company, costs will be directly assigned or distributed or allocated. For allocated services, the allocation method will be on a basis reasonably related to the service performed. The Service Company Utility Service Agreement prescribes 23 Service Company functions and approximately 20 allocation methods.

Functions and Allocation Methods:

Information Systems
Number of Central Processing Unit Seconds Ratio/Millions of Instructions per Second
Number of Personal Computer Workstations Ratio
Number of Information Systems Servers Ratio
Number of Employees Ratio
Meters
Number of Customers Ratio
Transportation
Number of Employees Ratio
Three Factor Formula
Electric System Maintenance
Circuit Miles of Electric Transmission Lines Ratio
Circuit Miles of Electric Distribution Lines Ratio
Marketing and Customer Relations and Grid Solutions
Number of Customers Ratio
Electric Transmission & Distribution Engineering & Construction
Electric Transmission Plant's Construction - Expenditures Ratio
Electric Distribution Plant's Construction - Expenditures Ratio
Power Engineering & Construction
Electric Production Plant's Construction - Expenditures Ratio
Human Resources
Number of Employees Ratio
Supply Chain
Procurement Spending Ratio
Inventory Ratio
Facilities
Square Footage Ratio
Accounting
Three Factor Formula
Generating Unit MW Capability Ratio
Power Planning and Operations
Electric Peak Load Ratio
Weighted Avg of the Circuit Miles of Electric Distribution Lines Ratio and the Electric Peak Load Ratio
Sales Ratio
Weighted Avg of the Circuit Miles of Electric Transmission Lines Ratio and the Electric Peak Load Ratio
Generating Unit MW Capability Ratio
Public Affairs
Three Factor Formula
Weighted Avg of Number of Customers Ratio and Number of Employees Ratio
Legal
Three Factor Formula
Rates
Sales Ratio
Finance
Three Factor Formula
Rights of Way
Circuit Miles of Electric Transmission Lines Ratio
Circuit Miles of Electric Distribution Lines Ratio
Electric Peak Load Ratio
Internal Auditing
Three Factor Formula
Environmental, Health and Safety
Three Factor Formula
Sales Ratio
Fuels
Sales Ratio
Investor Relations
Three Factor Formula
Planning
Three Factor Formula
Executive
Three Factor Formula

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Compressor Stations

1. Report below details concerning compressor stations. Use the following subheadings: field compressor stations, products extraction compressor stations, underground storage compressor stations, transmission compressor stations, distribution compressor stations, and other compressor stations.
2. For column (a), indicate the production areas where such stations are used. Group relatively small field compressor stations by production areas. Show the number of stations grouped. Identify any station held under a title other than full ownership. State in a footnote the name of owner or co-owner, the nature of respondent's title, and percent of ownership if jointly owned.

Line No.	Name and Location of Compressor Station (a)	Compressor Type (b)	Number of Units at Compressor Station (c)	Certificated Horsepower for Each Compressor Station (d)	Plant Cost (e)	Expenses (except depreciation and taxes) Fuel (f)	Expenses (except depreciation and taxes) Power (g)	Expenses (except depreciation and taxes) Other (h)	Gas for Compressor Fuel in Dth (i)	Electricity for Compressor Station in kWh (j)	Operational Data Total Compressor Hours of Operation During Year (k)	Operational Data Number of Compressors Operated at Time of Station Peak (l)	Date of Station Peak (m)
1													
2													
3													
4													
5													
6													
7													
8													
9													
10													
11													
12													
13													
14													
15													
16													
17													
18													
19													
20													
21													
22													
23													

24													
25	Total												

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Gas Storage Projects

1. Report injections and withdrawals of gas for all storage projects used by respondent.

Line No.	Item (a)	Gas Belonging to Respondent (Dth) (b)	Gas Belonging to Others (Dth) (c)	Total Amount (Dth) (d)
	STORAGE OPERATIONS (in Dth)			
1	Gas Delivered to Storage			
2	January			
3	February			
4	March			
5	April			
6	May			
7	June			
8	July			
9	August			
10	September			
11	October			
12	November			
13	December			
14	TOTAL (Total of lines 2 thru 13)			
15	Gas Withdrawn from Storage			
16	January			
17	February			
18	March			
19	April			
20	May			
21	June			
22	July			
23	August			
24	September			
25	October			
26	November			

27	December			
28	TOTAL (Total of lines 16 thru 27)			

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Gas Storage Projects

1. On line 4, enter the total storage capacity certificated by FERC.
2. Report total amount in Dth or other unit, as applicable on lines 2, 3, 4, 7. If quantity is converted from Mcf to Dth, provide conversion factor in a footnote.

Line No.	Item (a)	Total Amount (b)
	STORAGE OPERATIONS	
1	Top or Working Gas End of Year	
2	Cushion Gas (Including Native Gas)	
3	Total Gas in Reservoir (Total of line 1 and 2)	
4	Certificated Storage Capacity	
5	Number of Injection - Withdrawal Wells	
6	Number of Observation Wells	
7	Maximum Days' Withdrawal from Storage	
8	Date of Maximum Days' Withdrawal	
9	LNG Terminal Companies (in Dth)	
10	Number of Tanks	
11	Capacity of Tanks	
12	**LNG Volume**	
13	Received at "Ship Rail"	
14	Transferred to Tanks	
15	Withdrawn from Tanks	
16	"Boil Off" Vaporization Loss	

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Transmission Lines

1. Report below, by state, the total miles of transmission lines of each transmission system operated by respondent at end of year.
2. Report separately any lines held under a title other than full ownership. Designate such lines with an asterisk, in column (d) and in a footnote state the name of owner, or co-owner, nature of respondent's title, and percent ownership if jointly owned.
3. Report separately any line that was not operated during the past year. Enter in a footnote the details and state whether the book cost of such a line, or any portion thereof, has been retired in the books of account, or what disposition of the line and its book costs are contemplated.
4. Report the number of miles of pipe to one decimal point.

Line No.	Designation (Identification) of Line or Group of Lines (a)	State (b)	Operation Type (c)	* (d)	Total Miles of Pipe (e)
1					
2					
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25	TOTAL				

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Transmission System Peak Deliveries

1. Report below the total transmission system deliveries of gas (in Dth), excluding deliveries to storage, for the period of system peak deliveries indicated below, during the 12 months embracing the heating season overlapping the year's end for which this report is submitted. The season's peak normally will be reached before the due date of this report, April 30, which permits inclusion of the peak information required on this page. Add rows as necessary to report all data. Number additional rows 6.01, 6.02, etc.

Line No.	Description (a)	Dth of Gas Delivered to Interstate Pipelines (b)	Dth of Gas Delivered to Others (c)	Total (b) + (c) (d)
	SECTION A: SINGLE DAY PEAK DELIVERIES			
1	Date(s):			
2	Volumes of Gas Transported			
3	No-Notice Transportation			
4	Other Firm Transportation			
5	Interruptible Transportation			
6	Other (Specify)			
6.1				
7	TOTAL			
8	Volumes of gas Withdrawn form Storage under Storage Contract			
9	No-Notice Storage			
10	Other Firm Storage			
11	Interruptible Storage			
12	Other (Specify)			
12.1				
13	TOTAL			
14	Other Operational Activities			
15	Gas Withdrawn from Storage for System Operations			
16	Reduction in Line Pack			
17	Other (Specify)			
17.1				
18	TOTAL			
19	SECTION B: CONSECUTIVE THREE-DAY PEAK DELIVERIES			
20	Date(s):			
22	No-Notice Transportation			
23	Other Firm Transportation			

24	Interruptible Transportation			
25	Other (Specify)			
25.1				
26	TOTAL			
27	Volumes of gas Withdrawn form Storage under Storage Contract			
28	No-Notice Storage			
29	Other Firm Storage			
30	Interruptible Storage			
31	Other (Specify)			
31.1				
32	TOTAL			
33	Other Operational Activities			
34	Gas Withdrawn from Storage for System Operations			
35	Reduction in Line Pack			
36	Other (Specify)			
36.1				
37	TOTAL			

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Auxiliary Peaking Facilities

1. Report below auxiliary facilities of the respondent for meeting seasonal peak demands on the respondent's system, such as underground storage projects, liquefied petroleum gas installations, gas liquefaction plants, oil gas sets, etc.
2. For column (c), for underground storage projects, report the delivery capacity on February 1 of the heating season overlapping the year-end for which this report is submitted. For other facilities, report the rated maximum daily delivery capacities.
3. For column (d), include or exclude (as appropriate) the cost of any plant used jointly with another facility on the basis of predominant use, unless the auxiliary peaking facility is a separate plant as contemplated by general instruction 12 of the Uniform System of Accounts.

Line No.	Location of Facility (a)	Type of Facility (b)	Maximum Daily Delivery Capacity of Facility Dth (c)	Cost of Facility (in dollars) (d)	Was Facility Operated on Day of Highest Transmission Peak Delivery? (e)
1	Erlanger (KY)	Liquid Petroleum	25,060	12,922,730	false

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Gas Account - Natural Gas

1. The purpose of this schedule is to account for the quantity of natural gas received and delivered by the respondent.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Enter in column (c) the year to date Dth as reported in the schedules indicated for the items of receipts and deliveries.
4. Enter in column (d) the respective quarter's Dth as reported in the schedules indicated for the items of receipts and deliveries.
5. Indicate in a footnote the quantities of bundled sales and transportation gas and specify the line on which such quantities are listed.
6. If the respondent operates two or more systems which are not interconnected, submit separate pages for this purpose.
7. Indicate by footnote the quantities of gas not subject to Commission regulation which did not incur FERC regulatory costs by showing (1) the local distribution volumes another jurisdictional pipeline delivered to the local distribution company portion of the reporting pipeline (2) the quantities that the reporting pipeline transported or sold through its local distribution facilities or intrastate facilities and which the reporting pipeline received through gathering facilities or intrastate facilities, but not through any of the interstate portion of the reporting pipeline, and (3) the gathering line quantities that were not destined for interstate market or that were not transported through any interstate portion of the reporting pipeline.
8. Indicate in a footnote the specific gas purchase expense account(s) and related to which the aggregate volumes reported on line No. 3 relate.
9. Indicate in a footnote (1) the system supply quantities of gas that are stored by the reporting pipeline, during the reporting year and also reported as sales, transportation and compression volumes by the reporting pipeline during the same reporting year, (2) the system supply quantities of gas that are stored by the reporting pipeline during the reporting year which the reporting pipeline intends to sell or transport in a future reporting year, and (3) contract storage quantities.
10. Also indicate the volumes of pipeline production field sales that are included in both the company's total sales figure and the company's total transportation figure. Add additional information as necessary to the footnotes.

Line No.	Item (a)	Ref. Page No. of (FERC Form Nos. 2/2-A) (b)	Total Amount of Dth Year to Date (c)	Current Three Months Ended Amount of Dth Quarterly Only (d)
1	Name of System			
2	GAS RECEIVED			
3	Gas Purchases (Accounts 800-805)		11,405,342	
4	Gas of Others Received for Gathering (Account 489.1)	303		
5	Gas of Others Received for Transmission (Account 489.2)	305	8,579,821	
6	Gas of Others Received for Distribution (Account 489.3)	301	4,914,361	
7	Gas of Others Received for Contract Storage (Account 489.4)	307		
8	Gas of Others Received for Production/Extraction/Processing (Account 490 and 491)			
9	Exchanged Gas Received from Others (Account 806)	328		
10	Gas Received as Imbalances (Account 806)	328		
11	Receipts of Respondent's Gas Transported by Others (Account 858)	332		
12	Other Gas Withdrawn from Storage (Explain)			
13	Gas Received from Shippers as Compressor Station Fuel			
14	Gas Received from Shippers as Lost and Unaccounted for			
15	Other Receipts (Specify) (footnote details)			
15.1	Other Receipts		157,243	
16	Total Receipts (Total of lines 3 thru 15)		25,056,767	
17	GAS DELIVERED			
18	Gas Sales (Accounts 480-484)		10,031,090	
19	Deliveries of Gas Gathered for Others (Account 489.1)	303		

20	Deliveries of Gas Transported for Others (Account 489.2)	305	8,579,821	
21	Deliveries of Gas Distributed for Others (Account 489.3)	301	4,384,120	
22	Deliveries of Contract Storage Gas (Account 489.4)	307		
23	Gas of Others Delivered for Production/Extraction/Processing (Account 490 and 491)			
24	Exchange Gas Delivered to Others (Account 806)	328		
25	Gas Delivered as Imbalances (Account 806)	328		
26	Deliveries of Gas to Others for Transportation (Account 858)	332		
27	Other Gas Delivered to Storage (Explain)			
28	Gas Used for Compressor Station Fuel	509		
29	Other Deliveries and Gas Used for Other Operations			
29.1	Other Deliveries		5,610	
30	Total Deliveries (Total of lines 18 thru 29)		23,000,641	
31	GAS LOSSES AND GAS UNACCOUNTED FOR			
32	Gas Losses and Gas Unaccounted For		2,056,126	
33	TOTALS			
34	Total Deliveries, Gas Losses & Unaccounted For (Total of lines 30 and 32)		25,056,767	

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Shipper Supplied Gas for the Current Quarter

1. Report monthly (1) shipper supplied gas for the current quarter and gas consumed in pipeline operations, (2) the disposition of any excess, the accounting recognition given to such disposition and the specific account(s) charged or credited, and (3) the source of gas used to meet any deficiency, the accounting recognition given to the gas used to meet the deficiency, including the accounting basis of the gas and the specific account(s) charged or credited.
2. On lines 7, 14, 22 and 30 report only the dekatherms of gas provided by shippers under tariff terms and conditions for gathering , production/ extraction/processing, transmission, distribution and storage service and the use of that gas for compressor fuel, other operational purposes and lost and unaccounted for. The dekatherms must be broken out by functional categories on Lines 2-6, 9-13, 16-21 and 24-29. The dekatherms must be reported in column (d) unless the company has discounted or negotiated rates which should be reported in columns (b) and (c).
3. On lines 7, 14, 22 and 30 report only the dollar amounts of gas provided by shippers under tariff terms and conditions for gathering, production/ extraction/processing, transmission, distribution and storage service and the use of that gas for compressor fuel, other operational purposes and lost and unaccounted for. The dollar amounts must be broken out by functional categories on Lines 2-6, 9-13, 16-21 and 23-29. The dollar amounts must be reported in column (h) unless the company has discounted or negotiated rates which should be reported in columns (f) and (g). The accounting should disclose the account(s) debited and credited in columns (n) and (o).
4. Indicate in a footnote the basis for valuing the gas reported in Columns (f), (g) and (h).
5. Report in columns (j), (k) and (l) the amount of fuel waived, discounted or reduced as part of a negotiated rate agreement.
6. On lines 32-37 report the dekatherms and dollar value of the excess or deficiency in shipper supplied gas broken out by functional category and whether recourse rate, discounted or negotiated rate.
7. On lines 39 through 51 report the dekatherms, the dollar amount and the account(s) credited in Column (o) for the dispositions of gas listed in column (a).
8. On lines 53 through 65 report the dekatherms, the dollar amount and the account(s) debited in Column (n) for the sources of gas reported in column (a).
9. On lines 66 and 67, report forwardhaul and backhaul volume in Dths of throughput.
10. Where appropriate, provide a full explanation of the allocation process used in reported numbers in a footnote.

		Month 1													
						Amount Collected (Dollars)				Volume (in Dth) Not Collected					
Line No.	Item (a)	Discounted rate Dth (b)	Negotiated Rate Dth (c)	Recourse Rate Dth (d)	Total Dth (e)	Discounted Rate, Amount (f)	Negotiated Rate Amount (g)	Recourse rate Amount (h)	Total Amount (i)	Waived Dth (j)	Discounted Dth (k)	Negotiated Dth (l)	Total Dth (m)	Account(s) Debited (n)	Account(s) Credited (o)
1	SHIPPER SUPPLIED GAS (LINES 13 AND 14 , PAGE 520)														
2	Gathering														
3	Production/Extraction/Processing														
4	Transmission														
5	Distribution														
6	Storage														
7	Total Shipper Supplied Gas														
	LESS GAS USED FOR COMPRESSOR STATION FUEL (LINE 28, PAGE 520)														
9	Gathering														
10	Production/Extraction/Processing														
11	Transmission														
12	Distribution														
13	Storage														
14	Total gas used in compressors														
15	LESS GAS USED FOR OTHER DELIVERIES AND GAS USED FOR OTHER OPERATIONS (LINE 29, PAGE 520) (Footnote)														
16	Gathering														

17	Production/Extraction/Processing														
18	Transmission														
19	Distribution														
20	Storage														
21	Other Deliveries (specify) (footnote details)														
22	Total Gas Used For Other Deliveries And Gas Used For Other Operations														
23	LESS GAS LOST AND UNACCOUNTED FOR (LINE 32, PAGE 520)														
24	Gathering														
25	Production/Extraction/Processing														
26	Transmission														
27	Distribution														
28	Storage														
29	Other Losses (specify) (footnote details)														
30	Total Gas Lost And Unaccounted For														
30.1	NET EXCESS OR (DEFICIENCY)														
31	Other Losses														
32	Gathering														
33	Production/Extraction/Processing														
34	Transmission														
35	Distribution														
36	Storage														
37	Total Net Excess Or (Deficiency)														
38	DISPOSITION OF EXCESS GAS:														
39	Gas sold to others														
40	Gas used to meet imbalances														
41	Gas added to system gas														
42	Gas returned to shippers														
43.1															
43.2															
43.3															
43.4															
43.5															
43.6															

43.7															
43.8															
51	Total Disposition Of Excess Gas														
52	GAS ACQUIRED TO MEET DEFICIENCY:														
53	System gas														
54	Purchased gas														
55.1															
55.2															
55.3															
55.4															
55.5															
55.6															
55.7															
55.8															
55.9															
55.10															
65	Total Gas Acquired To Meet Deficiency														

SEPARATION OF FORWARDHAUL AND BACKHAUL THROUGHPUT

Line No.	Item (a)	Quarter Dth (b)
66	Forwardhaul Volume in Dths for the Quarter	
67	Backhaul Volume in Dths for the Quarter	
68	TOTAL (Lines 66 and 67)	

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Shipper Supplied Gas for the Current Quarter

1. Report monthly (1) shipper supplied gas for the current quarter and gas consumed in pipeline operations, (2) the disposition of any excess, the accounting recognition given to such disposition and the specific account(s) charged or credited, and (3) the source of gas used to meet any deficiency, the accounting recognition given to the gas used to meet the deficiency, including the accounting basis of the gas and the specific account(s) charged or credited.
2. On lines 7, 14, 22 and 30 report only the dekatherms of gas provided by shippers under tariff terms and conditions for gathering , production/ extraction/processing, transmission, distribution and storage service and the use of that gas for compressor fuel, other operational purposes and lost and unaccounted for. The dekatherms must be broken out by functional categories on Lines 2-6, 9-13, 16-21 and 24-29. The dekatherms must be reported in column (d) unless the company has discounted or negotiated rates which should be reported in columns (b) and (c).
3. On lines 7, 14, 22 and 30 report only the dollar amounts of gas provided by shippers under tariff terms and conditions for gathering, production/ extraction/processing, transmission, distribution and storage service and the use of that gas for compressor fuel, other operational purposes and lost and unaccounted for. The dollar amounts must be broken out by functional categories on Lines 2-6, 9-13, 16-21 and 23-29. The dollar amounts must be reported in column (h) unless the company has discounted or negotiated rates which should be reported in columns (f) and (g). The accounting should disclose the account(s) debited and credited in columns (n) and (o).
4. Indicate in a footnote the basis for valuing the gas reported in Columns (f), (g) and (h).
5. Report in columns (j), (k) and (l) the amount of fuel waived, discounted or reduced as part of a negotiated rate agreement.
6. On lines 32-37 report the dekatherms and dollar value of the excess or deficiency in shipper supplied gas broken out by functional category and whether recourse rate, discounted or negotiated rate.
7. On lines 39 through 51 report the dekatherms, the dollar amount and the account(s) credited in Column (o) for the dispositions of gas listed in column (a).
8. On lines 53 through 65 report the dekatherms, the dollar amount and the account(s) debited in Column (n) for the sources of gas reported in column (a).
9. On lines 66 and 67, report forwardhaul and backhaul volume in Dths of throughput.
10. Where appropriate, provide a full explanation of the allocation process used in reported numbers in a footnote.

		Month 2													
						Amount Collected (Dollars)				Volume (in Dth) Not Collected					
Line No.	Item (a)	Discounted rate Dth (b)	Negotiated Rate Dth (c)	Recourse Rate Dth (d)	Total Dth (e)	Discounted Rate, Amount (f)	Negotiated Rate Amount (g)	Recourse rate Amount (h)	Total Amount (i)	Waived Dth (j)	Discounted Dth (k)	Negotiated Dth (l)	Total Dth (m)	Account(s) Debited (n)	Account(s) Credited (o)
1	SHIPPER SUPPLIED GAS (LINES 13 AND 14 , PAGE 520)														
2	Gathering														
3	Production/Extraction/Processing														
4	Transmission														
5	Distribution														
6	Storage														
7	Total Shipper Supplied Gas														
8	LESS GAS USED FOR COMPRESSOR STATION FUEL (LINE 28, PAGE 520)														
9	Gathering														
10	Production/Extraction/Processing														
11	Transmission														
12	Distribution														
13	Storage														
14	Total gas used in compressors														
15	LESS GAS USED FOR OTHER DELIVERIES AND GAS USED FOR OTHER OPERATIONS (LINE 29, PAGE 520) (Footnote)														
16	Gathering														

17	Production/Extraction/Processing														
18	Transmission														
19	Distribution														
20	Storage														
21	Other Deliveries (specify) (footnote details)														
22	Total Gas Used For Other Deliveries And Gas Used For Other Operations														
23	LESS GAS LOST AND UNACCOUNTED FOR (LINE 32, PAGE 520)														
24	Gathering														
25	Production/Extraction/Processing														
26	Transmission														
27	Distribution														
28	Storage														
29	Other Losses (specify) (footnote details)														
30	Total Gas Lost And Unaccounted For														
30.1	NET EXCESS OR (DEFICIENCY)														
31	Other Losses														
32	Gathering														
33	Production/Extraction/Processing														
34	Transmission														
35	Distribution														
36	Storage														
37	Total Net Excess Or (Deficiency)														
38	DISPOSITION OF EXCESS GAS:														
39	Gas sold to others														
40	Gas used to meet imbalances														
41	Gas added to system gas														
42	Gas returned to shippers														
43.1															
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43.7															
43.8															
51	Total Disposition Of Excess Gas														
52	GAS ACQUIRED TO MEET DEFICIENCY:														
53	System gas														
54	Purchased gas														
55.1															
55.2															
55.3															
55.4															
55.5															
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55.8															
55.9															
55.10															
65	Total Gas Acquired To Meet Deficiency														

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

Shipper Supplied Gas for the Current Quarter

1. Report monthly (1) shipper supplied gas for the current quarter and gas consumed in pipeline operations, (2) the disposition of any excess, the accounting recognition given to such disposition and the specific account(s) charged or credited, and (3) the source of gas used to meet any deficiency, the accounting recognition given to the gas used to meet the deficiency, including the accounting basis of the gas and the specific account(s) charged or credited.
2. On lines 7, 14, 22 and 30 report only the dekatherms of gas provided by shippers under tariff terms and conditions for gathering , production/ extraction/processing, transmission, distribution and storage service and the use of that gas for compressor fuel, other operational purposes and lost and unaccounted for. The dekatherms must be broken out by functional categories on Lines 2-6, 9-13, 16-21 and 24-29. The dekatherms must be reported in column (d) unless the company has discounted or negotiated rates which should be reported in columns (b) and (c).
3. On lines 7, 14, 22 and 30 report only the dollar amounts of gas provided by shippers under tariff terms and conditions for gathering, production/ extraction/processing, transmission, distribution and storage service and the use of that gas for compressor fuel, other operational purposes and lost and unaccounted for. The dollar amounts must be broken out by functional categories on Lines 2-6, 9-13, 16-21 and 23-29. The dollar amounts must be reported in column (h) unless the company has discounted or negotiated rates which should be reported in columns (f) and (g). The accounting should disclose the account(s) debited and credited in columns (n) and (o).
4. Indicate in a footnote the basis for valuing the gas reported in Columns (f), (g) and (h).
5. Report in columns (j), (k) and (l) the amount of fuel waived, discounted or reduced as part of a negotiated rate agreement.
6. On lines 32-37 report the dekatherms and dollar value of the excess or deficiency in shipper supplied gas broken out by functional category and whether recourse rate, discounted or negotiated rate.
7. On lines 39 through 51 report the dekatherms, the dollar amount and the account(s) credited in Column (o) for the dispositions of gas listed in column (a).
8. On lines 53 through 65 report the dekatherms, the dollar amount and the account(s) debited in Column (n) for the sources of gas reported in column (a).
9. On lines 66 and 67, report forwardhaul and backhaul volume in Dths of throughput.
10. Where appropriate, provide a full explanation of the allocation process used in reported numbers in a footnote.

Line No.	Item (a)	Month 3													
						Amount Collected (Dollars)				Volume (in Dth) Not Collected					
		Discounted rate Dth (b)	Negotiated Rate Dth (c)	Recourse Rate Dth (d)	Total Dth (e)	Discounted Rate, Amount (f)	Negotiated Rate Amount (g)	Recourse rate Amount (h)	Total Amount (i)	Waived Dth (j)	Discounted Dth (k)	Negotiated Dth (l)	Total Dth (m)	Account(s) Debited (n)	Account(s) Credited (o)
1	SHIPPER SUPPLIED GAS (LINES 13 AND 14 , PAGE 520)														
2	Gathering														
3	Production/Extraction/Processing														
4	Transmission														
5	Distribution														
6	Storage														
7	Total Shipper Supplied Gas														
8	LESS GAS USED FOR COMPRESSOR STATION FUEL (LINE 28, PAGE 520)														
9	Gathering														
10	Production/Extraction/Processing														
11	Transmission														
12	Distribution														
13	Storage														
14	Total gas used in compressors														
15	LESS GAS USED FOR OTHER DELIVERIES AND GAS USED FOR OTHER OPERATIONS (LINE 29, PAGE 520) (Footnote)														
16	Gathering														

17	Production/Extraction/Processing														
18	Transmission														
19	Distribution														
20	Storage														
21	Other Deliveries (specify) (footnote details)														
22	Total Gas Used For Other Deliveries And Gas Used For Other Operations														
23	LESS GAS LOST AND UNACCOUNTED FOR (LINE 32, PAGE 520)														
24	Gathering														
25	Production/Extraction/Processing														
26	Transmission														
27	Distribution														
28	Storage														
29	Other Losses (specify) (footnote details)														
30	Total Gas Lost And Unaccounted For														
30.1	NET EXCESS OR (DEFICIENCY)														
31	Other Losses														
32	Gathering														
33	Production/Extraction/Processing														
34	Transmission														
35	Distribution														
36	Storage														
37	Total Net Excess Or (Deficiency)														
38	DISPOSITION OF EXCESS GAS:														
39	Gas sold to others														
40	Gas used to meet imbalances														
41	Gas added to system gas														
42	Gas returned to shippers														
43.1															
43.2															
43.3															
43.4															
43.5															
43.6															

43.7															
43.8															
51	Total Disposition Of Excess Gas														
52	GAS ACQUIRED TO MEET DEFICIENCY:														
53	System gas														
54	Purchased gas														
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55.2															
55.3															
55.4															
55.5															
55.6															
55.7															
55.8															
55.9															
55.10															
65	Total Gas Acquired To Meet Deficiency														

Name of Respondent: Duke Energy Kentucky, Inc	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/18/2022	Year/Period of Report: End of: 2021/ Q4

System Maps

1. Furnish five copies of a system map (one with each filed copy of this report) of the facilities operated by the respondent for the production, gathering, transportation, and sale of natural gas. New maps need not be furnished if no important change has occurred in the facilities operated by the respondent since the date of the maps furnished with a previous year's annual report. If, however, maps are not furnished for this reason, reference should be made in the space below to the year's annual report with which the maps were furnished.
2. Indicate the following information on the maps: (a) Transmission lines. (b) Incremental facilities. (c) Location of gathering areas. (d) Location of zones and rate areas. (e) Location of storage fields. (f) Location of natural gas fields. (g) Location of compressor stations. (h) Normal direction of gas flo (indicated by arrows). (i) Size of pipe. (j) Location of products extraction plants, stabilization plants, purification plants, recycling areas, etc. (k) Principal communities receiving service through the respondent's pipeline.
3. In addition, show on each map: graphic scale of the map; date of the facts the map purports to show; a legend giving all symbols and abbreviations used; designations of facilities leased to or from another company, giving name of such other company.
4. Maps not larger than 24 inches square are desired. If necessary, however, submit larger maps to show essential information. Fold the maps to a size not larger then this report. Bind the maps to the report.

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