COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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

CASE NO. 2024-00354

FILING REQUIREMENTS

VOLUME 16

Duke Energy Kentucky, Inc.
Case No. 2024-00354
Forecasted Test Period Filing Requirements
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Vol. #	Tab #	Filing Requirement	Description	Sponsoring Witness
1	1	KRS 278.180	30 days' notice of rates to PSC.	Amy B. Spiller
1	2	807 KAR 5:001 Section 7(1)	The original and 10 copies of application plus copy for anyone named as interested party.	Amy B. Spiller
1	3	807 KAR 5:001 Section 12(2)	(a) Amount and kinds of stock authorized. (b) Amount and kinds of stock issued and outstanding. (c) Terms of preference of preferred stock whether cumulative or participating, or on dividends or assets or otherwise. (d) 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 thereby, and the amount of indebtedness actually secured, together with any sinking fund provisions. (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 date of issue, face value, rate of interest, date of maturity and how secured, together with amount of interest paid thereon during the last fiscal year. (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. (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. (h) 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. (i) Detailed income statement and balance sheet.	Thomas J. Heath, Jr. Danielle L. Weatherston
1	4	807 KAR 5:001 Section 14(1)	Full name, mailing address, and electronic mail address of applicant and reference to the particular provision of law requiring PSC approval.	Amy B. Spiller
1	5	807 KAR 5:001 Section 14(2)	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.	Amy B. Spiller

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.	Lisa D. Steinkuhl Grady "Tripp" S. Carpenter Sharif S. Mitchell Jacob S. Colley
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 William C. Luke Marc W. Arnold
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 William C. Luke Marc W. Arnold
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 William C. Luke Marc W. Arnold

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 John D. Swez Ibrar A. Khera
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.	Thomas J. Heath, Jr.
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.	Thomas J. Heath, Jr.
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.	Danielle L. Weatherston Grady "Tripp" S. Carpenter
3-9	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
9	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
9	38	807 KAR 5:001 Section 16(7)(r)	Quarterly reports to the stockholders for the most recent 5 quarters.	Thomas J. Heath, Jr.

9	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
9	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
9	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.	Rebekah E. Buck
10	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
10	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
10	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

10	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 Sharif S. Mitchell Grady "Tripp" S. Carpenter John R. Panizza James E. Ziolkowski Danielle L. Weatherston
10	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
10	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 Sharif S. Mitchell Grady "Tripp" S. Carpenter Jacob S. Colley James E. Ziolkowski
10	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
10	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
10	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 Shannon A. Caldwell
10	51	807 KAR 5:001 Section 16(8)(h)	Computation of gross revenue conversion factor for forecasted period.	Lisa D. Steinkuhl
10	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
10	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.	Thomas J. Heath, Jr.
10	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.	Sharif S. Mitchell Grady "Tripp" S. Carpenter Thomas J. Heath, Jr. Danielle L. Weatherston
10	55	807 KAR 5:001 Section 16(8)(l)	Narrative description and explanation of all proposed tariff changes.	Bruce L. Sailers
10	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
10	57	807 KAR 5:001 Section 16(8)(n)	Typical bill comparison under present and proposed rates for all customer classes.	Bruce L. Sailers
10	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

10	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.	Legal
10	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
10	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

10	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

10	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
10	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

11	-	807 KAR 5:001 Section 16(8)(a) through (k)	Schedule Book (Schedules A-K)	Various
12	-	807 KAR 5:001 Section 16(8)(l) through (n)	Schedule Book (Schedules L-N)	Bruce L. Sailers
13	-	-	Work Papers	Various
14	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 1 of 4)	Various
15	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 2 of 4)	Various
16	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 3 of 4)	Various
17	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 4 of 4)	Various
18-19	-	KRS 278.2205(6)	Cost Allocation Manual	Legal

TESTIMONY

VOLUME 3 OF 4

GRADY "TRIPP" S. CARPENTER
THOMAS "TK" CHRISTIE
JACOB S. COLLEY
THOMAS J. HEATH, JR.
MATTHEW KALEMBA
IBRAR A. KHERA
SARAH E. LAWLER
WILLIAM C. LUKE
JAMES J. McCLAY
SHARIF S. MITCHELL
JOSHUA C. NOWAK
JOHN R. PANIZZA
BRUCE L. SAILERS

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. 2024-00354

DIRECT TESTIMONY OF

GRADY "TRIPP" S. CARPENTER

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 2, 2024

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Grady "Tripp" S. Carpenter and my business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS) as Director, Regional Financial Forecasting. DEBS provides various administrative and other services to Duke Energy Kentucky Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Science degree in Business Administration with a Finance concentration from the University of North Carolina at Wilmington and a Master of Accounting degree from the University of North Carolina at Chapel Hill. I am a licensed Certified Public Accountant in the state of North Carolina. After nine years working in various roles within public accounting and private industry, I joined Duke Energy as a senior accounting analyst in 2013. Subsequently, I held various positions of increasing responsibility within the Controller's and Financial Planning and Analysis departments. In 2021, I became the Forecasting Manager for Duke Energy Ohio and its subsidiary, Duke Energy Kentucky, Inc. (Duke Energy Kentucky). In 2022, I assumed financial forecasting responsibility for Duke Energy's other natural gas utilities and gas ventures and was promoted to Director, Regional Financial Forecasting.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS DIRECTOR, REGIONAL FINANCIAL FORECASTING.

A. I am responsible for leading the preparation of budgets, forecasts, and financial analysis for Duke Energy Kentucky's electric and natural gas utilities, as well as Duke Energy Ohio and other gas utilities and gas ventures.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THESE PROCEEDINGS?

A. My testimony will address Duke Energy Kentucky's budgeting and forecasting process underlying the projected data for the test year proposed in this Application. I also discuss the budget variance reports, which provide the variance analysis for the test period. I sponsor and support the forecasted operating revenues and expenses prior to proforma adjustments and the long-term financial forecast that were prepared under my direction and control. I sponsor Filing Requirements (FR) 16(6)(a), 16(6)(b), 16(6)(d), 16(6)(e), 16(7)(b), 16(7)(c), 16(7)(d), 16(7)(f), 16(7)(g), 16(7)(h), and 16(7)(o). In response to FR 16(8)(b), I co-sponsor Schedules B-2, B-2.1, B-2.2, B-2.3, B-2.4, B-2.5, B-2.6, B-2.7, B-3, B-3.1, B-3.2, and B-4 with Duke Energy Kentucky witness Mr. Sharif S. Mitchell. I sponsor the information contained in B-5 and B-5.1. Company witness Mr. Michael J. Adams provided me with the cash working capital included in these schedules as supported by the lead-lag study he prepared. I also sponsor certain information contained in

Schedule B-8 that is also supported by Duke Energy Kentucky witness Ms. Danielle L. Weatherston. In response to FR 16(6)(a), 16(6)(b) and 16(8)(d), I sponsor Schedules D-2.1 through D-2.16. I also sponsor the forecasted data on Schedules I-1 through I-5 in response to FR 16(8)(i), and certain information on Schedule K in response to FR 16(8)(k).

II. THE BUDGETING AND FORECASTING PROCESS

Q. DESCRIBE THE SOURCE OF THE FORECASTED FINANCIAL DATA USED IN THESE PROCEEDINGS.

A. The forecasted data used in these proceedings is based on Duke Energy Kentucky's 2024 and 2025 annual budgets. The Company is also using a fully forecasted test period that, for this proceeding, spans the twelve-month period ending June 30, 2026. The budget and forecast were reviewed and approved by Duke Energy Kentucky's executive management and Duke Energy's Board of Directors. Updates to the forecast may be made for material changes that occur that were not known at the time of Board approval. Those changes are reviewed by executive management.

Q. HOW DID YOU USE THE 2024 AND 2025 ANNUAL BUDGETS RESULTS FOR THE BASE AND FORECASTED PERIODS IN THIS PROCEEDING?

A. The base period is the twelve months ending February 28, 2025 and consists of six months of actual data through August 31, 2024 and the remaining six months of budgeted data. The forecasted test period is the twelve months ending June 30, 2026. The Company's 2024 actual data and 2024 and 2025 budgets were the starting point for the preparation of both the base and forecasted periods. A simplistic high-level summary of that approach is as follows. First, I revised the 2024 and 2025 annual budgets for a limited number of updated assumptions, as I describe in detail later in my testimony. Next, I extended the revised 2025 annual budget to June 2026 using the Company's standard forecasting methodology, which I also describe later in my testimony when I explain how I prepared the financial forecasts.

Q. DESCRIBE THE BUDGETING AND FORECASTING PROCESS THAT YOU USED TO DEVELOP THE TEST PERIOD IN THESE PROCEEDINGS.

A. Each entity (or group) that performs work throughout the organization is assigned a responsibility center, which is specific to a single payroll company. The responsibility centers use guidelines provided by Duke Energy's Forecast Systems and Reporting organization within the Financial Planning and Analysis Department. The responsibility centers represent detailed responsibility budgets consisting of expense items, certain types of revenues, and construction budgets for capital projects. The information is consolidated, along with sales and revenue data, into a corporate budget and is reviewed by various levels of management. One or more iterations of the annual budget are typically required before final approval by executive management and the Board of Directors. This "bottom-up" approach is reasonable and has been an effective process for managing costs.

Q. DESCRIBE THE GUIDELINES PROVIDED BY THE FORECAST SYSTEMS AND REPORTING ORGANIZATION IN DEVELOPING DUKE ENERGY KENTUCKY'S ANNUAL RESPONSIBILITY (OPERATING AND MAINTENANCE) CENTER BUDGET.

A. The guidelines provided by the Forecast Systems and Reporting organization are a detailed set of instructions for creating a responsibility center budget. For example, there are detailed instructions for budgeting employee labor data, such as the escalation rates for union and non-union labor expenses and fringe benefit loading rates. Detailed instructions for non-labor related expenses, such as transportation (fleet) expenses, are included along with instructions for handling contract labor. The Company follows internal capitalization guidelines when identifying a capital versus expense item. Budget coordinators are required to use these assumptions and/or instructions in projecting their future departmental expenses. These operating and maintenance (O&M) budgeting guidelines are reflected in the budgets and forecasts that are submitted to Duke Energy Kentucky's executive management and Duke Energy's Board of Directors for approval and are also reflected in the forecasted financial data in these proceedings.

Q. WHAT OTHER STEPS ARE INVOLVED IN DEVELOPING THE CORPORATE BUDGET?

A. In addition to the O&M expenses and capital data provided by the budgeting process, other forecasted information is required as follows:

1. Operating revenues;

2. Projected fuel, purchased power, emission allowance, other production costs and off-system sales;
3. Depreciation;
4. Property taxes;
5. Other Income and Expense, primarily allowance for funds used during construction (AFUDC);
6. Financing assumptions, including short- and long-term debt rates, dividend policy, issuances and redemptions, and capital leases; and
7. Tax rates and tax depreciation.

III. METHODOLOGY FOR THE FORECASTED DATA

Q. PLEASE DESCRIBE HOW THIS FORECASTED INFORMATION WAS USED FOR THE CORPORATE BUDGET AND LATER REVISED AND/OR EXTENDED THROUGH THE BASE AND FORECAST PERIODS.

A. I will do so by describing the three primary financial statements beginning with the income statement.

A. Income Statement

Q. PLEASE DESCRIBE HOW THE OPERATING REVENUES WERE FORECASTED.

A. The first step in preparing the operating revenues for the 2024 and 2025 annual budgets was to obtain a forecast of the projected electric kilowatt per hour (kWh) sales and natural gas sales on a thousand cubic feet basis (MCF) from Duke Energy Kentucky witness Mr. Ibrar A. Khera, Lead Load Forecasting Analyst, who prepared the load forecasts on a monthly basis. The forecasts are updated at least annually. The Load Forecasting and Fundamentals organization also provides the forecasted number of customers for each customer class. The projected revenues for the annual budget and the long-range forecast for kWh and MCF sales were calculated by applying the tariff charges and base customer charges to these sales and customer forecast numbers for all electric and natural gas residential customers. The projected revenue for electric and natural gas non-residential customers was calculated by applying average realizations to their respective kWh and MCF sales forecasts.

Q. ARE THE REVENUE PROJECTIONS BASED ON WEATHER NORMALIZED LOAD FORECASTS?

A. Yes. As described by Mr. Khera, a thirty-year (30) historical period was used as the basis for calculating normal weather. This is the same methodology that management relies on for preparing its budgets and forecasts, and for financial presentations to the Board of Directors, credit rating agencies, and the investment community.

Q. HOW WERE OTHER REVENUES PROJECTED?

A. Other revenue categories, such as PJM reactive revenues, reconnection charges, *etc.*, for Duke Energy Kentucky's 2024 and 2025 annual budgets are projected based on historical trends or are provided by the individual budget centers. Additionally, Duke Energy Kentucky witness Mr. John D. Swez used the PowerSIMM® Model to provide me with forecasts of the power production costs, such as fuel, emission allowances and purchase power costs, and revenues, such as off-system sales, after applying the Company's off-system sales sharing mechanism (Rider PSM).

Q. HOW WERE PRODUCTION COSTS SUCH AS FUEL, EMISSION ALLOWANCES, PURCHASED POWER, AND REVENUES SUCH AS OFF-SYSTEM SALES PROJECTED?

A. As described by Mr. Swez, the Company utilizes a commercially available production cost model (PowerSIMM® Model) to develop the forecast utilized in the Company's annual budgets. All of the Company's generating units are represented in the model with their key characteristics, such as capacity, fuel type, heat rate, and emission rates. Outputs from this model are utilized to project the associated revenues and production costs.

Q. DESCRIBE HOW DEPRECIATION EXPENSE IS INCLUDED IN THE FORECAST.

A. The forecasted depreciation for existing and projected electric and natural gas plant is calculated by multiplying the depreciable plant by appropriate composite depreciation rates. These composite rates for electric generation, transmission, distribution, common and general plant are based on rates currently in effect and established in the Company's 2022 electric base rate case, Case No. 2022-00372.

The projected electric and natural gas capital budget data was prepared by the responsibility centers for a five-year period at the time of the 2024 and 2025 annual budgets preparation per Duke Energy's capital budgeting process, which I discussed earlier. The electric capital budget data was obtained from Duke Energy Kentucky's operating functions, including the distribution, transmission, and generation organizations. These numbers were revised to reflect the latest cost estimates and timing of capital expenditures for various projects designed to maintain or enhance reliability and service to customers including construction projects at the East Bend station for compliance and reliability initiatives. These projects are described in the direct testimonies of Mr. William C. Luke and Mr. Marc W. Arnold, respectively.

Q. DESCRIBE HOW O&M EXPENSES ARE INCLUDED IN THE FORECAST.

A. The O&M expenses, including benefits and payroll taxes, were obtained from the 2024 and 2025 annual budgets by the various responsibility centers, using the bottom-up approach that I described above. Duke Energy Kentucky's proportionate share of the shared services expenses and the corporate center O&M expenses are assigned and/or allocated from the service company to Duke Energy Kentucky and are also derived using the same bottom-up approach. The allocated share is derived by the application of appropriate allocations based on the service company allocation factors, and in accordance with various Commission-approved service agreements as discussed in the direct testimony of Duke Energy Kentucky witness, Ms. Rebekah E. Buck. For labor-related expenses, I used the projected annual labor cost rate increases provided by Duke Energy Kentucky witness Ms. Shannon A. Caldwell to budget 2024 and 2025 union and non-union employee labor expense. Union labor cost increases were assumed to be between 2.5 percent and 3.6 percent, depending on the agreements, while non-union labor cost increases were assumed to be 3.5 percent (including both merit increases of 3 percent and an allowance for salary increases for promotions of 0.5 percent). I also used the fringe benefit loading rates (25.61 percent for 2024 and 2025) and payroll tax (7.5 percent in each year) loadings. Non-labor expenses for 2024 and 2025 were forecasted by the responsibility centers based on their knowledge and expectations for various costs.

Q. HOW WAS THE O&M REVISED AND EXTENDED THROUGH THE FORECASTED PERIOD?

A. As mentioned above, O&M budgets were supplied by the responsibility centers for 2024 and 2025 per the company's Budget Guidelines. In certain instances, new or revised information emerged which supported the need for revisions to previously supplied O&M budgets and projections. The basis for the 2026 budget is the 2025 budget adjusted for planned labor cost increases and other various O&M expenses that are expected to diverge from 2025 amounts.

Q. HOW DID YOU OBTAIN THE PROPERTY TAX EXPENSE?

A. Duke Energy Kentucky witness Mr. John R. Panizza supplied the property tax expenses for the forecasted financial test period data, based on the capital projections and forecasted plant balances.

Q. HOW DID YOU OBTAIN THE "OTHER INCOME AND EXPENSE"?

A. The "other income and expense" is a below-the-line item and is derived from a combination of sources. The amount of funds for the AFUDC was derived from the electric and natural gas capital forecasts prepared for the 2024 and 2025 annual budgets. These capital forecasts were supplied by Duke Energy Kentucky's operating functions, including the distribution, transmission, and generation organizations.

Q. HOW DID YOU OBTAIN THE INCOME TAX EXPENSE?

A. Mr. Panizza provided the appropriate income tax rates and the amortization of investment tax credit (ITC) and Excess Accumulated Deferred Income Taxes (EDIT). The income tax expense was derived using Utilities International (UI) Planner or “proprietary forecasting” software for each month of the revised 2024-2025 annual budget period and the 2026 forecast, by applying statutory income tax rates to applicable taxable book income and adjusting the resulting applicable income taxes by the ITC and EDIT amortization amounts.

B. Balance Sheet Statement

Q. HOW WERE INITIAL BALANCES ESTABLISHED FOR THE BALANCE SHEET?

A. The final month of actual data for the base period was the August 31, 2024 balances. Mr. Mitchell supplied the net book value for the existing electric, natural gas, general and common plant, and construction work in progress for the period ending August 31, 2024. I used the proprietary forecasting software to calculate the depreciation expense and net electric, natural gas, general and common plant, and construction work in progress balances for the forecasted period.

Q. WHAT OTHER INFORMATION WAS USED TO ESTABLISH THE BASE AND FORECASTED BALANCE SHEETS?

A. Mr. Arnold and Mr. Luke provided the capital expenditures for the forecasted portion of the base period and for the forecasted test period. All of the forecasted capital data was prepared for the 2024 and 2025 annual budgets and was completed for a five-year period as typically done.

In addition, Ms. Weatherston supplied the plant inventories for emission allowances, coal, oil and gas and materials and supplies.

C. Cash Flow Statement

Q. HOW DID YOU PREPARE THE CASH FLOW STATEMENT FOR THE 2024 AND 2025 ANNUAL BUDGETS?

A. The cash flow statement is generated by Duke Energy's proprietary forecasting software tools. It is derived from corresponding inputs from the income statement and changes in the balance sheet.

IV. REASONABLENESS OF THE FORECASTED TEST PERIOD DATA

Q. DO YOU HAVE AN OPINION AS TO WHETHER THE FORECASTED TEST PERIOD FINANCIAL DATA IS REASONABLE, RELIABLE, MADE IN GOOD FAITH, AND THAT ALL BASIC ASSUMPTIONS USED IN THE FORECAST HAVE BEEN IDENTIFIED AND JUSTIFIED?

A. Yes, the forecasted test period financial data is reasonable, reliable and made in good faith, based on all the information available as of the time of this filing. In my opinion, as Director, Regional Financial Forecasting, the budgeting and forecasting processes are adequate, reasonable, and reliable. My testimony has identified all the basic assumptions in the forecast. These assumptions are justified by my testimony and the testimony of the other witnesses I have identified.

Q. DOES THE FORECAST CONTAIN THE SAME ASSUMPTIONS AND METHODOLOGIES USED IN FORECASTED DATA PREPARED FOR USE BY MANAGEMENT?

A. Yes.

Q. DOES THE FORECASTED TEST PERIOD REFLECT ANY IDENTIFIED PRODUCTIVITY AND EFFICIENCY GAINS?

A. Yes. The forecasted data reflects all expected productivity and efficiency gains.

V. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE FR 16(6)(a).

A. FR 16(6)(a) is the forecasted period in the form of pro forma adjustments to the base period. Our assumptions and methodologies have been described in my testimony as well as other witnesses in this case.

Q. PLEASE DESCRIBE FR 16(6)(b).

A. FR 16(6)(b) requires that the forecasted adjustments are limited to the twelve months immediately following the suspension period.

Q. PLEASE DESCRIBE FR 16(6)(d).

A. FR 16(6)(d) requires that there be no revisions to the forecast after filing. The Company will comply with this requirement.

Q. PLEASE DESCRIBE FR 16(6)(e).

A. FR 16(6)(e) provides that the Commission may require the utility to prepare an alternative forecast based upon a reasonable number of changes in the variables, assumptions and other factors used as the basis for the utility's forecast. The Company will comply with this if requested.

Q. PLEASE DESCRIBE FR 16(7)(b).

A. FR 16(7)(b) consists of the Company's most recent capital construction budget containing a minimum three (3) year forecast of construction expenditures.

Q. PLEASE DESCRIBE FR 16(7)(c).

A. FR 16(7)(c) is a summary of the assumptions used to prepare the forecasted test period data. Our assumptions and methodologies have also been described in my testimony and the testimony of other witnesses I identified earlier.

Q. PLEASE DESCRIBE FR 16(7)(d).

A. FR 16(7)(d) is Duke Energy Kentucky's annual and monthly budget for the twelve-months preceding the filing date, the base period and forecasted period.

Q. PLEASE DESCRIBE FR 16(7)(f).

A. FR 16(7)(f) includes specific information for each major construction project that constitutes five (5) percent or more of the annual construction budget within the three (3) year forecast. This information includes the date the project was or is estimated to be started, the estimated completion date, and the total estimated cost of construction by year exclusive and inclusive of AFUDC or interest during construction credit, and the most recent available total costs incurred exclusive and inclusive of AFUDC.

Q. PLEASE DESCRIBE FR 16(7)(g).

A. FR 16(7)(g) includes an aggregate of the information included in FR 16(7)(f) for all construction projects that constitute less than five (5) percent of the annual construction budget within three (3) years of the forecast.

Q. PLEASE DESCRIBE FR 16(7)(h).

A. FR 16(7)(h) is Duke Energy Kentucky's financial forecast corresponding to the three-year capital budget. This includes an income statement, a balance sheet, a statement of cash flow, and certain other required financial and statistical information.

Q. PLEASE DESCRIBE FR 16(7)(o).

A. FR 16(7)(o) consists of management's monthly variance reports for the twelve months prior to the base period, each month of the base period and subsequent months as available. These reports are self-explanatory and include explanations on the variances.

Q. PLEASE DESCRIBE THE INFORMATION YOU SUPPORT IN SCHEDULES B-2, B-2.1, B-2.2, B-2.3, B-2.4, B-2.5, B-2.6, B-2.7, B-3, B-3.1, B-3.2, AND B-4.

A. I provided Mr. Mitchell with the forecasted data contained in those schedules.

Q. PLEASE DESCRIBE SCHEDULE B-5.

A. Schedule B-5 is a summary of the jurisdictional working capital comprised of the cash element of working capital, material and supplies inventory, fuel inventory, emission allowance inventory and prepayments. The cash working capital calculation is based on the lead-lag study supported by Mr. Adams.

Q. PLEASE DESCRIBE SCHEDULE B-5.1.

A. Schedule B-5.1 reflects the itemized miscellaneous working capital items for both the base and forecasted periods.

Q. PLEASE EXPLAIN THE MATERIALS AND SUPPLIES INVENTORY ON SCHEDULE B-5.1.

A. The materials and supplies shown on Schedule B-5.1 represent the 13-month average for the forecasted period and the end of period balance for the base period. These supplies consist primarily of supplies kept on hand in the Company's storerooms. These investments assure that adequate supplies are available to provide reliable service to customers. The 13-month average of material and supplies included in electric working capital for the forecasted test period is $20,096,676.

Q. PLEASE EXPLAIN THE FUEL AND EMISSION ALLOWANCE INVENTORIES ON SCHEDULE B-5.1.

A. The fuel and emission allowance inventories shown on Schedule B-5.1 represent the 13-month average for the forecasted period and the end of period balance for the base period. The 13-month average balances of fuel and emission allowance inventories included in electric working capital for the forecasted test period are $15,445,163. Emission allowance balances have been removed from the forecasted test period since emission allowances are included for recovery in the Company's Environmental Surcharge Mechanism (Rider ESM).

Q. PLEASE EXPLAIN THE PREPAYMENTS ON SCHEDULE B-5.1.

A. The prepayments shown on Schedule B-5.1 represent the 13-month average for the forecasted period and the end of the period balance for the base period. The 13-month average balances of prepayments in electric working capital for the forecasted test period are $2,119,316 related to prepaid insurance and planned outage hedging collateral.

Q. PLEASE EXPLAIN THE CASH WORKING CAPITAL COMPUTATION ON SCHEDULE B-5.1.

A. Cash working capital was computed for both the base and forecasted periods. It represents the financing incurred to bridge the gap between the time when expenditures are incurred to provide service and the time when payment is received for that service. The cash working capital computation is based upon the lead-lag study sponsored by Mr. Adams. The resulting jurisdictional cash working capital is $4,507,797for the forecasted period.

Q. PLEASE DESCRIBE SCHEDULE B-8.

A. Schedule B-8 includes the comparative balance sheets for Duke Energy Kentucky. I sponsor the forecasted data included on this schedule.

Q. PLEASE DESCRIBE SCHEDULE D-2.1.

A. Schedule D-2.1 adjusts base period revenue to the level included in the forecasted test period. The adjustment results in a net revenue decrease of $21,212,170.

Q. PLEASE DESCRIBE SCHEDULE D-2.2.

A. Schedule D-2.2 adjusts base period fuel and purchased power expenses to the level included in the forecasted test period. The effect of the adjustment on Duke Energy Kentucky's electric operations is a decrease in pre-tax operating expenses of $7,955,234.

Q. PLEASE DESCRIBE SCHEDULE D-2.3.

A. Schedule D-2.3 adjusts base period other production expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $3,808,146.

Q. PLEASE DESCRIBE SCHEDULE D-2.4.

A. Schedule D-2.4 was not used in this filing.

Q. PLEASE DESCRIBE SCHEDULE D-2.5.

A. Schedule D-2.5 adjusts base period transmission expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $4,296,729.

Q. PLEASE DESCRIBE SCHEDULE D-2.6.

A. Schedule D-2.6 adjusts base period regional market expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $669,967.

Q. PLEASE DESCRIBE SCHEDULE D-2.7.

A. Schedule D-2.7 adjusts base period electric distribution expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $2,016,745.

Q. PLEASE DESCRIBE SCHEDULE D-2.8.

A. Schedule D-2.8 adjusts base period customer accounts expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $66,570.

Q. PLEASE DESCRIBE SCHEDULE D-2.9.

A. Schedule D-2.9 adjusts base period customer service and information expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $338,753.

Q. PLEASE DESCRIBE SCHEDULE D-2.10.

A. Schedule D-2.10 adjusts base period sales expense to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $103,983.

Q. PLEASE DESCRIBE SCHEDULE D-2.11.

A. Schedule D-2.11 adjusts base period administrative and general expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $2,996,380.

Q. PLEASE DESCRIBE SCHEDULE D-2.12.

A. Schedule D-2.12 adjusts base period other operating expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is a decrease of pre-tax operating expenses of $3,748,440.

Q. PLEASE DESCRIBE SCHEDULE D-2.13.

A. Schedule D-2.13 adjusts base period depreciation expense to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $4,396,406.

Q. PLEASE DESCRIBE SCHEDULE D-2.14.

A. Schedule D-2.14 adjusts base period taxes other than income taxes to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $2,241,624.

Q. PLEASE DESCRIBE SCHEDULE D-2.15.

A. Schedule D-2.15 adjusts base period income taxes to the level included in the forecasted test period. The effect of the adjustment on electric operations is a decrease in income tax expense of $206,157.

Q. PLEASE DESCRIBE SCHEDULE D-2.16.

A. Schedule D-2.16 is an adjustment to annualize revenue and fuel expense in the forecasted test period. The overall effect of the adjustment on pre-tax electric operations is to increase revenues in the forecasted test year by $1,714,280 and increase fuel expense by $2,161,285.

Q. PLEASE DESCRIBE SCHEDULES I-1 THROUGH I-5.

A. Schedule I-1 contains comparative income statements for the Company. Schedules I-2.1 through I-5 contains comparative revenue and sales statistical information as required by the Commission's filing requirements. I support the forecasted information on these schedules.

Q. PLEASE DESCRIBE SCHEDULE K.

A. Schedule K contains comparative financial and statistical information, as required by the Commission's filing requirements. I provided the forecasted plant data on page 1, the condensed income statement on page 2, the forecasted earnings per share on page 4, and the mix of sales and fuel on page 5, for the base period and the forecasted test period.

VI. CONCLUSION

Q. WAS THE INFORMATION YOU SPONSOR IN 16(6)(A), 16(6)(B), 16(6)(D), 16(6)(E), 16(7)(B), 16(7)(C), 16(7)(D), 16(7)(F), 16(7)(G), 16(7)(H), 16(7)(O), 16(8)(B), 16(8)(D), 16(8)(I), AND 16(8)(K), THE INFORMATION YOU PROVIDED TO MR. MITCHELL FOR SCHEDULES B-2, B-2.1, B-2.2, B-2.3, B-2.4, B-2.5, B-2.6, B-2.7, B-3, B-3.1, B-3.2, B-4, SCHEDULES B-5 AND B-5.1, THE INFORMATION YOU PROVIDED TO MS. WEATHERSTON IN SUPPORT OF SCHEDULE B-8, SCHEDULES D-2.1 THRU D-2.16, AS WELL AS SCHEDULES I-1 THROUGH I-5, AND SCHEDULE K PREPARED BY OR SPONSORED AND SUPPORTED BY YOU?

A. Yes.

Q. IS THE INFORMATION CONTAINED IN THOSE SCHEDULES ACCURATE TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

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. 2024-00354

DIRECT TESTIMONY OF

THOMAS "TK" K. CHRISTIE

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC

December 2, 2024

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Thomas "TK" K. Christie, and my business address is 100 South Mill Creek Road, Noblesville, Indiana 46062.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS) as Director, Transmission & Distribution (T&D) Vegetation Management. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy), including Duke Energy Ohio, Inc., (Duke Energy Ohio) and Duke Energy Indiana, LLC (Duke Energy Indiana).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I am a graduate of the University of South Florida with a Bachelor of Science in Industrial Engineering and a graduate of Webster University with a master's degree in business administration. I have been in the electric utility industry for 29 years.

Q. PLEASE DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS DIRECTOR T&D VEGETATION MANAGEMENT.

A. As Director, T&D Vegetation Management, I am responsible for overseeing Duke Energy's Midwest vegetation management activities for more than 41,000 miles of electric T&D lines across the Duke Energy's service territories in Ohio, Kentucky, and Indiana. In this capacity, I manage a staff of 23 employees, all of whom are International Society of Arboriculture (ISA) certified arborists and have primary responsibility for vegetation management in the Duke Energy Kentucky, Duke Energy Ohio, and Duke Energy Indiana service territories. I also serve as the primary jurisdictional leader responsible for overseeing the Company's contractors who are performing vegetation management. I ensure adherence to the contract strategy, terms, and work plan execution to the Company's standards. I develop and monitor performance metrics and objectives in collaboration with contractors to ensure that Duke Energy Kentucky's vegetation management program is performed in accordance with the rules and regulations of the Kentucky Public Service Commission (Commission). I analyze budget and work plan status to ensure performance goals are on target. I also ensure consistent implementation of policies and procedures.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I will describe Duke Energy Kentucky's current T&D vegetation management program, which focuses on maintaining our existing rights-of-way, identification, and removal of hazard and danger trees. I will also discuss the Company's proposed update to the vegetation management program that incorporates a condition-based approach to our Integrated Vegetation Management (IVM) strategy for distribution. This approach leverages remotely sensed imagery (i.e., satellite) and a probability model to develop a condition-based maintenance strategy.

II. DUKE ENERGY KENTUCKY'S CURRENT VEGETATION MANAGEMENT PROGRAM

Q. PLEASE PROVIDE AN OVERVIEW OF DUKE ENERGY KENTUCKY'S VEGETATION MANAGEMENT PROGRAM GOALS.

A. Duke Energy Kentucky's electric service territory covers five counties in northern Kentucky. Duke Energy Kentucky supplies electric service to approximately 155,000 residential, commercial, and industrial customers. Duke Energy Kentucky's vegetation management goal is to balance the need for reliable electric service with cost-effective vegetation management practices.

The Duke Energy Kentucky Vegetation Management Program is based on an IVM strategy, with the primary objective being to control the growth of incompatible vegetation along its electric infrastructure to provide reliable service to our customers and the safe operation of Duke Energy assets. This is accomplished by using qualified personnel to monitor the condition of the utility rights-of-way and by initiating various vegetation management practices to reduce or eliminate incompatible growth.

The consistent implementation of industry accepted vegetation management practices reduces the likelihood of tree and electric infrastructure conflicts, as well as service interruptions, and allows for the full utilization of the operating system.

Q. PLEASE EXPLAIN THE COMPANY'S IVM STRATEGY TOWARDS VEGETATION MANAGEMENT?

A. The Company's IVM strategy applies to both T&D and focuses on delivering reliable electric service in a cost-effective manner while utilizing industry best management practices for vegetation management. Duke Energy Kentucky takes a proactive approach to its vegetation management program, which means we use qualified contract vegetation management companies to prune or cut down trees and other vegetation that may cause problems before service is affected. Duke Energy Kentucky's primary focus is to control the growth of incompatible vegetation along its electric infrastructure by monitoring the condition of vegetation over, under, and adjacent to our electric facilities.

As part of the IVM strategy and in addition to our planned routine work, the Company also utilizes various vegetation management practices to reduce or eliminate incompatible growth, such as the use of herbicides and mowing. Vegetation along electric infrastructure lines, if not properly maintained, can create serious risks to reliability as well as the safe operation of Duke Energy assets.

Q. PLEASE PROVIDE AN OVERVIEW OF DUKE ENERGY KENTUCKY'S DISTRIBUTION VEGETATION MANAGEMENT (VM) PROGRAM

A. Duke Energy Kentucky's distribution VM program is based on maintaining and clearing all the Company's distribution circuits every five years. Consistent with the Kentucky Public Service Commission's October 26, 2007, Order[1] in Case No. 2006-00494, the Company developed a distribution vegetation management plan that is on file with the Commission. The current full-system maintenance inspection and work cycle covers approximately 1,431 miles of distribution overhead lines to be maintained. A five-year work cycle is approximately 286 miles per year. A copy

[1] *In the Matter of An Investigation of the Reliability Measures of Kentucky's Jurisdictional Electric Distribution Utilities,* Case No. 2006-00494 (Ky. P.S.C. Oct. 26, 2007).

of the current Distribution VM plan is included as Attachment TKC-1 to my testimony.

The Company's vegetation management plan includes a description of the Company's tree care standards and pruning specifications that include minimum clearances, brush and wood removal, and customer notifications. The Company provides the Commission with an annual report of its vegetation management plan in accordance with the Commission's Order in Case No. 2011-00450.[2] The last report was filed on May 1, 2024.

Duke Energy Kentucky works consistently to balance aesthetics with our goal to provide safe, reliable power to the households and businesses that depend on us. It is our responsibility to ensure power lines are free of trees and other obstructions that could disrupt electric service. Trees that are close to power lines must be pruned or cut down to ensure they do not cause power outages, and Duke Energy Kentucky does much of this work proactively. The necessary crews use a variety of methods to manage vegetation growth along both distribution and transmission rights of way, including vegetation pruning, felling (cutting down) and herbicides. These methods are based on widely accepted standards developed by the tree care industry. All work is performed in conformance with Duke Energy Kentucky's vegetation management requirements, OSHA regulations, American National Standards Institute (ANSI) A300, ANSI Z133, Tree Care Industry Association's (formerly the National Arborist Association) standards, Dr. Shigo's

[2] *In the Matter of An Investigation of the Reliability Measures of Kentucky's Jurisdictional Electric Distribution Utilities,* Case No. 2011-00450 (Ky. P.S.C. May 30, 2013).

Field Guide for Qualified Line Clearance Tree Workers, National Electrical Safety Code (NESC), International Society of Arboriculture Best Management Practices, and all federal, state, county, and municipal laws, statutes, ordinances, and regulations applicable to said work.

Q. AS PART OF ITS ROUTINE 5-YEAR WORK CYCLE FOR THE DISTRIBUTION VEGETATION MANAGEMENT PROGRAM, DESCRIBE THE RELIABILITY, SAFETY, AND OTHER CRITERIA USED IN DETERMINING WHETHER TREES AND VEGETATION REQUIRE WORK.

A. Duke Energy Kentucky's distribution VM program uses data analytics to prioritize annual vegetation management plans. This analysis considers age since previous pruning, customer satisfaction data, and vegetation related outages since the previous pruning. The Company uses foresters who are certified by the ISA to provide guidance and oversight to contractors who are pruning trees and clearing brush growth around, over, and under power lines. In addition to the routine work cycle, we perform periodic visual inspections to determine whether the Company's targeted 10 feet of clearance along the distribution lines is maintained or requires additional attention in advance of the schedule. During routine vegetation maintenance, our employees and contractors also identify hazard trees that pose a risk and remove the affected trees once permissions are received. Our Hazard Tree Removal Program is another component of our IVM strategy for the distribution VM program.

Q. DESCRIBE HOW THE HAZARD TREE REMOVAL PROGRAM SUPPORTS SYSTEM RELIABILITY AND STORM HARDENING?

A. To maintain safety and reliability, Duke Energy Kentucky is engaged in a Hazard Tree Removal Program that is designed to remove trees that pose a potential danger to our distribution system. This program seeks to remove living and dead trees outside of the Company's right-of-way that pose a risk to our distribution system, including ash trees, to counter the effects of the Emerald Ash Borer infestation.

There are two components to the Hazard Tree Program. First, when our contractors are performing routine work, they are instructed to look outside the ten-foot clearance zone. If they identify trees that are infested with the Emerald Ash Borer or otherwise are a threat to our distribution lines, we will work with our customers to remove the tree.

The second component of this initiative occurs outside the normal work cycle. The Company has retained "Hazard Tree Identifiers" or contractor foresters who conduct visual inspections and identify hazard trees in our service territory. Our contractor will then work with our customers to obtain permission to remove these trees before they have a chance to damage our system.

Over the past five years, approximately 40% of the total distribution vegetation related outages, including Major Event Days (MEDs), in Kentucky were due to trees falling on distribution lines from outside the right-of-way. Overall, vegetation related outages account for approximately 17% of all distribution outages in Kentucky. Because of this, Duke Energy Kentucky has and will continue its program to remove hazard trees that are likely to cause a problem with Duke

Energy Kentucky's distribution system from outside the Company's right-of-way to drive reliability and storm resiliency.

Q. PLEASE PROVIDE AN OVERVIEW OF ENHANCEMENTS TO DUKE ENERGY KENTUCKY'S DISTRIBUTION VEGETATION MANAGEMENT PROGRAM.

At a high level, there are typically three types of maintenance strategies, time-based, condition-based, and predictive-based maintenance. Time-based maintenance is what has been historically utilized in the industry. This involves a period or cycle-based vegetation management strategy that is over a period of years. It is not based upon analytical data, just a goal of performing vegetation management for a defined number of circuits or miles a year, over a period of years.

But with the advancement in technology and computer processing, the industry is transitioning to a condition-based strategy. This condition-based approach leverages technology and analytics to identify potential incompatible vegetation risks and determine where, when, and how much vegetation work is needed. If you have good data and information, then you can utilize a condition-based maintenance strategy.

Duke Energy's distribution vegetation management is leveraging more advanced technologies such as remotely sensed imagery (i.e., satellite) and a probability model to develop a condition-based maintenance strategy that optimizes reliability risks while balancing cost and resource needs.

Q. PLEASE PROVIDE AN OVERVIEW OF DUKE ENERGY KENTUCKY'S TRANSMISSION VEGETATION MANAGEMENT PROGRAM.

A. As previously approved, Duke Energy's Kentucky transmission VM program follows an IVM strategy along with associated industry standards just like the distribution VM program that targets removal or control of incompatible vegetation to minimize potential outages to the transmission system and ensure necessary access within all transmission line corridors. The reason for the transmission IVM strategy is to create, promote, and conserve sustainable plant communities that are compatible with the intended use of the site, and manage incompatible plants that may conflict with the reliable operation of the transmission system. This approach is recognized as an industry best management practice and is in alignment with ANSI A300 Part 7 standard. The objective of this IVM approach is to maintain the transmission right-of-way such that compatible, low growing woody-shrub species and herbaceous grasses can exist in the right-of-way corridor. The program focuses on the removal and/or control of incompatible vegetation within or along the corridor to minimize the risk of vegetation-related outages, maintain adequate clearances, and ensure necessary access within all transmission line corridors.

Q. PLEASE DESCRIBE THE COMPONENTS OF THE TRANSMISSION VM PROGRAM.

A. The transmission VM program includes the following annual activities:

- Planned Corridor Work is prioritized and scheduled using remote sensing, annual aerial patrol, and field assessment data while considering other factors such as the date of previous work and outage history.

- Reactive Work, including hazard tree mitigation, is identified and prioritized through the remote sensing, annual aerial inspections, and on-going field inspections.
- Floor Management (herbicide, mowing, and hand cutting) is focused on managing incompatible vegetation in the floor of the corridor and is a time-based program.

The transmission program focuses on a threat and condition-based maintenance approach using technology, including remote sensing Light Detection and Ranging (LiDAR) to monitor and address vegetation conditions across all jurisdictions.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY COMPATIBLE AND INCOMPATIBLE VEGETATION WITHIN THE TRANSMISSION RIGHT-OF-WAY.

A. Duke Energy Kentucky utilizes a process to define compatible and incompatible vegetation to balance the needs of public and worker safety as well as the reliable operation of the transmission system. A time-based herbicide program is used to further manage incompatible vegetation in the right-of-way and to support the IVM strategy.

Compatible vegetation is vegetation within the transmission right-of-way that *will not* mature to a height or size that will pose a grow-in, fall-in, or blowing-together threat to the transmission conductor, or that will not limit, block access, or inhibit the safe and reliable operation, emergency restoration, or maintenance activity, which is typically within 25 feet of any Duke Energy facilities (towers, poles, guy wires, guy anchors, etc.).

Conversely, incompatible vegetation is vegetation within or outside the transmission right-of-way that will mature to a height or size that *will* pose a grow-in, fall-in, or blowing-together threat to the transmission conductor, or that will limit, block access, or inhibit the safe and reliable operation, emergency restoration, or maintenance activity, which is typically within 25 feet of any Duke Energy facilities (towers, poles, guy wires, guy anchors, etc.).

III. DUKE ENERGY KENTUCKY'S VEGETATION MANAGEMENT PROGRAM GOING FORWARD

Q. PLEASE SUMMARIZE DUKE ENERGY KENTUCKY'S APPROACH TO VEGETATION MANAGEMENT FOR 2025 -2026.

A. Duke Energy Kentucky will continue to implement the IVM program strategy as previously described for both transmission and distribution. For the distribution VM program, the Company will continue to operate under its approved five-year routine work cycle as well as execute the Hazard Tree Removal Program in 2025 and transition from a five-year time-based cycle to a condition-based approach for 2026 for routine maintenance. Additionally, the transmission VM program will continue to implement its threat-and condition-based approach for its transmission system which includes Planned, Reactive, and Floor Management work activities. The continued focus by both distribution and transmission on removals will help ensure reliability and support storm hardening of the Duke Energy Kentucky electric system.

IV. CONCLUSION

Q. DO YOU BELIEVE THAT DUKE ENERGY KENTUCKY'S VEGETATION MANAGEMENT PROGRAM AS OUTLINED IN YOUR TESTIMONY WILL ALLOW THE COMPANY TO CONTINUE TO PROVIDE RELIABLE SERVICE AND SAFE OPERATION OF DUKE ENERGY ASSETS?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, it does.

Vegetation Management Program – Duke Energy Kentucky, Inc

CONTENTS

Distribution Vegetation Management Program – Duke Energy Kentucky, Inc

CONTENTS

SECTION 1- GOAL, OBJECTIVES, AND PURPOSE

Duke Energy Kentucky's vegetation management goal is to balance the need for reliable electrical service with cost-effective vegetation management practices.

The primary objective of the Duke Energy Kentucky Vegetation Management Program is to control the growth of incompatible vegetation along its electric infrastructure to provide reliable service to our customers. This is accomplished by using qualified personnel to monitor the condition of the utility rights- of-way and by initiating various vegetation management practices to reduce or eliminate incompatible growth. This integrated vegetation management program is essential to providing reliable electric service by ensuring that trees, brush and vines near or within rights-of-way are periodically pruned or taken down to help reduce outages and risks near the company's facilities.

The consistent implementation of industry accepted vegetation management practices reduces the likelihood of tree and power line conflicts, as well as service interruptions, and allows for the full utilization of the operating system.

SECTION 2 – DEFINITIONS

ANSI A300 - American National Standards Institute (ANSI) A300 for Tree Care Operations provides the generally accepted industry performance standards for the care and management of trees, shrubs, and other woody plants.

ANSI Z133 - American National Standards Institute (ANSI) Z133 for Arboricultural Operations provides the generally accepted industry safety standards for the care and management of trees, shrubs, and other woody plants.

BRUSH - A perennial woody stem less than six inches DBH (diameter at breast height).

CIRCUIT MILES - (for reference and reporting purposes) The distance, in miles, of primary voltage electric lines from the substation to the end of the circuit including single phase, two phase or three phase configurations. The distance is measured to the nearest 1/10th of a mile.

COMPATIBLE VEGETATION – Vegetation within the distribution right of way that does not present a grow-in or fall-in threat that has a typical mature height of less than 15 feet and whose trunk is typically no closer than 20 feet from the center of the right of way.

CONTRACTOR - Corporation to whom the vegetation management work is awarded.

DANGER TREE – A traditional industry term for a tree that if it were to fall or be cut would be tall enough to strike electrical lines and equipment of the distribution system.

HAZARD TREE - A traditional industry term for a tree that is dead, structurally unsound, diseased, shallow-rooted, leaning or otherwise defective that could strike electrical lines or equipment of the distribution system if it falls or is cut.

INCOMPATIBLE VEGETATION – Vegetation within or outside the distribution right of way that will mature to a height or size that will pose a grow-in, fall-in, or blowing-together threat to the distribution conductor, or that will limit or block access to distribution facilities during routine or emergency maintenance activity.

INTEGRATED VEGETATION MANAGEMENT - Vegetation plan that combines various components including pruning, mowing, removals, and herbicide applications to manage the growth of vegetation on the electric utility rights-of-way.

LEGAL- Duke Energy Legal Department.

MAINTAINED/LANDSCAPED AREAS - An area where cut brush typically cannot be left on-site. Maintained areas typically include maintained yards and landscaped areas.

NON-MAINTAINED/NON-LANDSCAPED AREAS - An area where cut brush can be left on-site. Non-Maintained areas are unimproved areas or natural areas.

OPEN WIRE SECONDARY (OWS): A distribution line configuration that uses 2, 3 or 4 un-insulated conductors stacked vertically with 12 inches spacing between conductors, used to deliver secondary voltages ranging from 120-600 volts to the customer.

SECTION 2 – DEFINITIONS CONTINUED

PRIMARY LINE: Electric conductor(s) energized at greater than 600 volts of electricity.

RIGHT-OF-WAY (ROW)- A strip of land that an electric utility uses to construct, operate, inspect, maintain, repair, or replace an overhead or underground power line. The ROW allows the utility to provide clearance from trees, buildings and other structures that could interfere with the line installation, maintenance, and operation. ROW may include licenses, easements, and other rights to access property.

SECONDARY LINE: Electric conductor(s) are energized at 600 volts or less of electricity.

SERVICE – TRIPLEX – MULTIPLEX CABLE: Electric conductor(s) energized at 600 volts or less of electricity and terminate at a service delivery point. A bundle of three or four conductors, most commonly used to provide aerial service to homes and businesses, denoted by its 3 or 4 polyethylene coated conductors wrapped around a bare, aluminum conductor.

SINGLE PHASE PRIMARY: A type of electric power line construction that contains one (1) conductor energized at primary voltage.

THREE PHASE PRIMARY: A type of electric power line construction that contains three (3) conductors energized at primary voltage.

TREE- A perennial woody stem equal or greater than six inches in DBH (diameter at breast height)

TWO PHASE OR OPEN WYE: A type of electric power line construction that contains two (2) conductors energized at primary voltage.

UNIT MILE: A mile within a circuit that is required to be or has been trimmed per contract specifications.

SECTION 3 – FEDERAL, STATE, AND LOCAL LAWS

Contractor shall perform all work in conformance with Duke Energy Kentucky Vegetation Management Program requirements and work specifications, Occupational Health and Safety Administration (OSHA) regulations, American National Standards Institute (ANSI) A300 and Z133 standards as amended, and all federal, state, county, and municipal laws, ordinances, and regulations applicable to said work.

The governing entities include but are not limited to:

- Kentucky Public Services Commission (Commission)
- Kentucky Transportation Cabinet (Department of Transportation)
- Kentucky Department of Agriculture
- Occupational Health and Safety Administration (OSHA)
- American National Standards Institute (ANSI)
- Easement and/or Permit Documents

SECTION 4 – PROPERTY ACCESS RIGHTS / REQUIREMENTS

The rights to access, assess, inspect, or perform the work associated with vegetation management practices include, but are not limited to, established legal instruments, easements, public road rights-of-way, municipal ordinances, state statutes, regulatory rules, tariffs, and other legal authority. Personnel responsible for implementing vegetation management on behalf of Duke Energy Kentucky should, when necessary, utilize the available supporting documents to pursue the completion of necessary work activities to maintain vegetation growth to the established standards of acceptance in the provision of safe and reliable electric service. If there are objections, restrictions or limitations that prevent completion of the necessary work activities, personnel should contact the Land Services Department or Legal Department for specialized assistance.

A list of items to determine property access rights include, but are not limited to:

- Existing property easement, prescriptive easements, public road rights of way and / or agreements
- State statutes
- Municipal codes
- Commission rules, regulations, orders, and approved tariffs.

SECTION 5 – WORK QUALITY AND SAFETY STANDARDS

All work shall be performed in conformance with the governing rules from the following: Duke Energy Kentucky Vegetation Management Program Requirements, OSHA regulations, National Electrical Safety Code (NESC), ANSI A300 Z133 Standards as amended and all federal, state, county, and municipal laws, statutes, ordinances, and regulations applicable to said work.

Clearance to obtain safety and reliable electric service are based on, but not limited to, consideration of the

following: NESC

ANSI A300 Standard - American National Standards Institute A300 for Tree Care Operations For utility line clearance work, the primary foci are PartsClauses 5,11, and 13.

ANSI Z133 Standard - American National Standards Institute Z133 for Tree Care Operations - Safety Requirements

OSHA Standard 29 Code of Federal Regulations (CFR) 1910.269 - OSHA Standard 29 CFR 1910.269 (a)(1)(i)(E) for Electric Power Generation, Transmission, and Distribution

Pruning Trees Near Electrical Utility Lines – A Field Pocket Guide for Qualified Line-Clearance Tree Workers by Dr. Alex L. Shigo

SECTION 6 –DISTRIBUTION VEGETATION MANAGEMENT OVERVIEW FOR PLANNED WORK

Based on a data driven approach to facilitate a 5-year trim cycle, Duke Energy Kentucky will review, and clear vegetation as needed from approximately 20% of distribution system miles annually. Vegetation maintenance may include tree pruning, mechanical limb removal, brush cutting/mastication, herbicide application and tree removal. The primary objective of the Duke Energy Kentucky Vegetation Management Program is to control the growth of incompatible vegetation and remove hazard trees along its electric lines to help provide reliable service to our customers by limiting or eliminating the possibility of contact by vegetation which has grown towards or could fall into the overhead distribution lines. This is accomplished by using qualified personnel to monitor the condition of the utility rights-of-way and by initiating various vegetation control practices to reduce, manage or eliminate incompatible growth.

The consistent implementation of industry accepted vegetation management practices reduces the likelihood of tree and power line conflicts, as well as service interruptions, and allows for the full utilization of the operating system.

Distribution Line Clearances

Trees located along the right-of-way edge will, in most cases, encroach upon the electrical conductors through the side growth of their limbs. The maintenance of these trees requires the removal or partial removal of those potentially interfering limbs. Industry standards dictate the methods of pruning such limbs to minimize any damages to the tree. Incompatible brush within the distribution right-of-way corridors is eliminated if possible. When such vegetation is eliminated, it will normally be cut down by manual or mechanical means.

- Primary distribution lines are typically cleared during routine pruning to obtain no less than ten feet of side clearance. Unsuitable branches which are dead, dying, diseased or structurally unsound and above distribution facilities are removed during pruning.
- Secondary, including open wire secondary distribution conductors (without a primary distribution line and excluding a service drop), are pruned on an as needed basis.
- Multiplex cables and guy wires (without a primary distribution line and excluding a service drop), are trimmed on an as needed basis. Removal of load bearing limbs that are in contact with conductors and have a size and weight that causes tension on the conductor or interference with the normal sag or alignment of the conductor will be pruned for a minimum of 12 inches of clearance.
- Duke Energy Kentucky shall have no responsibility to clear vegetation from a service drop.

Hazard Tree Mitigation

Trees found within or adjacent to the right-of way that are dead, structurally unsound, diseased, shallow-rooted, leaning or otherwise defective that pose unacceptable risks to electrical infrastructure are targeted to be taken down. Stumps from trees (live) taken down shall be treated with herbicides where appropriate.

SECTION 7 – INSPECTIONS AND MONITORING

Duke Energy Kentucky can and may perform inspections and assessments of distribution circuits to observe vegetation conditions on the distribution system. The intent of these inspections is to identify off-cycle vegetation threats along the distribution line corridors and take appropriate action.

Transmission Vegetation Management Program – Duke Energy Kentucky, Inc.

CONTENTS

SECTION 1 – GOALS, OBJECTIVES AND PURPOSE

Duke Energy Kentucky's vegetation management goal is to balance the need for reliable utility service with cost-effective vegetation management practices.

The primary objective of the Duke Energy Kentucky Vegetation Management Program is to control the growth of incompatible vegetation along its electric facilities to help provide reliable service to our customers. This is accomplished by using qualified personnel to monitor the condition of the utility rights-of-way and by initiating various vegetation control practices to reduce, manage or eliminate incompatible growth. This integrated vegetation management program is essential in providing reliable electric service by ensuring that trees and brush near or within rights-of-way are periodically trimmed or taken down to help reduce potential outages and hazards near our facilities.

The consistent implementation of industry accepted vegetation management practices reduces the likelihood of tree and power line conflicts, as well as service interruptions, and allows for the full utilization of the operating system.

SECTION 2 – DEFINITIONS

ANSI A300 - American National Standards Institute (ANSI) A300 for Tree Care Operations, provides the generally accepted industry performance standards for the care and management of trees, shrubs, and other woody plants.

ANSI Z133 - American National Standards Institute (ANSI) Z133 for Arboricultural Operations, provides the generally accepted industry safety standards for the care and management of trees, shrubs, and other woody plants.

ASSET PROTECTION - Duke Energy department that enforces transmission right of way legal rights. BRUSH - A

perennial woody stem less than six inches DBH (diameter at breast height).

COMPATIBLE VEGETATION – Vegetation within the Transmission Right of Way that will not mature to a height or size that will pose a grow-in, fall-in, or blowing-together threat to the transmission conductor, or that will not limit or block access, or the safe and reliable operation, emergency restoration, or maintenance activity, which is typically within 25 feet of any Duke Energy facilities (towers, poles, guy wires, guy anchors, etc.).

CONTRACTOR - Corporation to whom the Vegetation Management work is awarded.

CONDUCTOR BLOWOUT – Conductors horizontal position/location at National Electrical Safety Code (NESC) designed wind and temperature.

CONDUCTOR SAG – Conductors vertical position/location at designed maximum operating conditions.

DANGER TREE – A traditional industry term for a tree that if it were to fall or be cut would be tall enough to strike electrical lines and equipment of the transmission or distribution system.

HAZARD TREE - A traditional industry term for a tree that is dead, structurally unsound, diseased, shallow-rooted, leaning or otherwise defective that could strike electrical lines or equipment of the transmission system if it falls or is cut.

INCOMPATIBLE VEGETATION – Vegetation within or outside the Transmission Right of Way that will mature to a height or size that will pose a grow-in, fall-in, or blowing-together threat to the transmission conductor, or that will limit or block access, or the safe and reliable operation, emergency restoration, or maintenance activity, which is typically within 25 feet of any Duke Energy facilities (towers, poles, guy wires, guy anchors, etc.).

INTEGRATED VEGETATION MANAGEMENT - Vegetation plan that combines various components including pruning, mowing, removals, and herbicide applications to manage the growth of vegetation on the electric utility rights-of-way.

LEGAL- Duke Energy Legal Department.

MAINTAINED/LANDSCAPED AREAS - An area where cut brush typically cannot be left on-site. Maintained areas typically include maintained yards and landscaped areas.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION (NERC) CIRCUITS – Transmission lines typically operated at more than 200 kV. Some transmission lines operated at voltages lower than 200 kV may be designated as NERC circuits if deemed critical.

SECTION 2 – DEFINITIONS CONTINUED

NON-NERC CIRCUITS – Transmission lines that typically operate at less than 200 kV.

NON-MAINTAINED/NON-LANDSCAPED AREAS - An area where cut brush can be left on-site. Non-Maintained areas are unimproved areas or natural areas.

RECLAMATION – The establishment or reestablishment of Integrated Vegetation Management (IVM) objectives in areas not actively maintained.

RIGHT-OF-WAY (ROW)- A strip of land that an electric utility uses to construct, operate, inspect, maintain, repair, or replace an overhead or underground power line. The ROW allows the utility to provide clearance from trees, buildings and other structures that could interfere with line installation, maintenance, and operation. ROW may include licenses, easements, and other rights to access property.

TRANSMISSION LINE– A set of electrical conductors that carry 69 kV or more of electricity.

TREE- A perennial woody stem equal or greater than six inches in DBH (diameter at breast height)

SECTION 3 – FEDERAL, STATE, AND LOCAL LAWS

Contractor shall perform all work in conformance with the Duke Energy Kentucky Vegetation Management Program requirements and work specifications, Occupational Health and Safety Administration (OSHA) regulations, American National Standards Institute (ANSI) A300 and Z133 as amended, and all federal, state, county, and municipal laws, ordinances, and regulations applicable to said work.

The governing entities include but are not limited to:

- Kentucky Public Service Commission (Commission)
- Kentucky Transportation Cabinet (Department of Transportation)
- Kentucky Department of Agriculture
- Occupational Health and Safety Administration (OSHA)
- American National Standards Institute (ANSI)
- Easement and/or Permit Documents

SECTION 4 – PROPERTY ACCESS RIGHTS / REQUIREMENTS

The rights to access, assess, inspect, or perform the work associated with vegetation management practices include, but are not limited to, established legal instruments, easements, public road rights-of-way, municipal ordinances, state statutes, regulatory rules, tariffs, and other legal authority. Personnel responsible for implementing vegetation management on behalf of Duke Energy Kentucky should, when necessary, utilize the available supporting documents to pursue the completion of necessary work activities to maintain vegetation growth to the established standards of acceptance in the provision of reliable electric service. If there are objections, restrictions or limitations that prevent completion of the necessary work activities, Duke Energy Vegetation Management should contact the Land Services Department or Legal Department for specialized assistance.

A list of items to determine property access rights include, but are not limited to:

- Existing property easement, prescriptive easements, public road rights of way and / or agreements
- State statutes
- Municipal codes
- Commission rules, regulations, orders, and approved tariffs.

SECTION 5 – WORK QUALITY AND SAFETY STANDARDS

All work shall be performed in conformance with the governing rules from the following: Duke Energy Kentucky Vegetation Management Program Requirements, OSHA regulations, NESC and all federal, state, county, and municipal laws, statutes, ordinances, and regulations applicable to said work.

Clearance to obtain safety and reliable electric service are based on, but not limited to, consideration of the following:

National Electrical Safety Code (NESC)

ANSI A300 Standard - American National Standards Institute A300 for Tree Care Operations
- For utility line clearance work, the primary foci are Clauses 5, 11, and 13.

ANSI Z133 Standard - American National Standards Institute Z133 for Tree Care Operations - Safety Requirements

OSHA Standard 29 Code of Federal Regulations (CFR) 1910.269 -OSHA Standard 29 CFR 1910.269 (a)(1)(i)(E) for Electric Power Generation, Transmission, and Distribution

Pruning Trees Near Electrical Utility Lines – A Field Pocket Guide for Qualified Line-Clearance Tree Workers by Dr. Alex L. Shigo

SECTION 6 – TRANSMISSION VEGETATION MANAGEMENT OVERVIEW FOR PLANNED WORK

Duke Energy's program is designed on an Integrated Vegetation Management (IVM) strategy that targets removals of incompatible vegetation to minimize potential outages to the Transmission system and ensure necessary access within all transmission line corridors. The reason for IVM is to create, promote, and conserve sustainable plant communities that are compatible with the intended use of the site, and manage incompatible plants that may conflict with the intended use of the site. This approach is recognized as an industry best management practice and is in alignment with ANSI A300 Part 7 standard.

As part of an IVM strategy, Duke Energy utilizes a threat and condition-based approach to planned work. This approach of identifying threats as triggers to determine incompatible vegetation within and outside the Transmission Right of Way. Duke Energy utilizes a process to define compatible and incompatible vegetation to balance the needs of public and worker safety as well as the reliable operation of the Transmission system. A time-based herbicide program will be used to further manage the ROW of incompatible vegetation and support IVM.

THREAT/CONDITION-BASED TRIGGERS

For planned work, threat trigger distances are used to identify vegetation threats that do not allow for safe operation of the transmission facilities, under all operating conditions (designed blowout and designed maximum operating sag). These threat triggers are radial distances based on engineering design criteria for the conductor sag and blowout operating locations and are voltage dependent.

These threat trigger distances provide for approximately 6 years of typical vegetation re-growth and supports minimum safe worker distances. Once vegetation has been identified as a threat, the vegetation will be evaluated to determine a mitigation strategy through the work planning process.

THREAT/CONDITION-BASED ACTION

During the work planning and marking process, many factors and criteria must be considered when developing the mitigation strategy. A Duke Energy Kentucky utility vegetation management professional will evaluate the vegetation based on arboricultural, regulatory/safety standards, legal ROW rights and criteria such as size, age, location, growth rate, maintained/landscaped vs. non- maintained/non-landscaped, etc. Property owner concerns with the proposed mitigation strategy shall be communicated to Duke Energy Kentucky personnel and alternative mitigation strategies will be considered. One mitigation strategy includes herbicide application.

MITIGATION FOR INCOMPATIBLE VEGETATION THREATS

All identified incompatible vegetation will be evaluated and taken down.

SPECIAL/SPECIFIC SITUATIONS

Potential Outage Risk: When a Transmission outage risk is identified, Duke Energy Kentucky will attempt to notify the affected property owner if practical and possible. However, Duke Energy Kentucky may need to take immediate action, such as taking down the vegetation, to protect the reliability and security of the Transmission system.

Roadside: For situations such as roadside, overhead Transmission lines built within public road right of way with limited Transmission Right of Way rights, a Wire Zone / Border Zone approach will be utilized with property owners to manage vegetation threats within and outside of the public road right of way.

Off ROW Danger Tree: Duke Energy Kentucky personnel will focus on taking down danger tree threats for reliability and storm hardening purposes on narrow corridors or rural areas where rights outside of the easement allow.

Storm: During storm events, debris in maintained or landscaped areas associated with emergency operations restoration efforts will be left on site and is the responsibility of the property owner.

SECTION 7 – INSPECTION AND MONITORING

Duke Energy Kentucky can and may perform inspections on each transmission circuit (69kv and above) to observe vegetation conditions on the transmission system. The intent of these inspections is to identify off-cycle vegetation threats along the transmission line corridors and take appropriate action.

SECTION 8 – VEGETATION CONTROL METHODS

TREE PRUNING - Trees found within or adjacent to the right-of-way edge will, in most cases, encroach upon the electrical conductors through the growth of their limbs. The management of these trees requires the removal or partial removal of those potentially interfering limbs. Industry standards dictate the proper methods of "pruning" such limbs to minimize any damages to the tree. These methods are in alignment with industry standards which refer to natural pruning, drop crotch and lateral pruning techniques. Stubbing and tearing of bark shall be avoided. When utilizing boom mounted cutting devices or helicopters to perform the pruning activities in rural locations, proper pruning methods are not typically a viable option.

HAZARD TREE MITIGATION - Trees found within or adjacent to the right-of way that are dead, structurally unsound, diseased, shallow-rooted, leaning or otherwise defective that could strike electrical lines or equipment are targeted to be taken down. Stumps from downed trees shall be treated with herbicides where appropriate and possible.

INCOMPATIBLE VEGETATION MITIGATION (i.e., trees) - Trees which are in close proximity to electrical facilities can require extensive pruning to prevent them from causing reliability or safety risk. These trees within the right-of-way will be targeted to be taken down and Duke Energy Kentucky will attempt to notify the affected property owner.

BRUSH MANAGEMENT - Because of a variety of terrain, differences in soil, land use, and vegetation types, Duke Energy Kentucky uses IVM practices which include environmentally acceptable herbicides to control brush within the right-of-way. All herbicides used in brush management operations shall be registered with the EPA and the applicable regulating state authority. In situations where brush height is of significant size and therefore not conducive to herbicide applications, the right of way may be mechanically mowed. In landscaped/maintained areas, brush will typically be hand cut and the remaining stumps treated.

SECTION 9 – CONTRACTOR RESPONSIBILITIES

STANDARDS TO FOLLOW - Contractor shall perform all work in conformance with Duke Energy Kentucky Vegetation Management Program requirements (Contract Terms and Conditions).

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. 2024-00354

DIRECT TESTIMONY OF

JACOB S. COLLEY

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 2, 2024

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ATTACHMENTS:

I. INTRODUCTION AND PURPOSE

Q. **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Jacob S. Colley, and my business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

Q. **BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I am employed by Duke Energy Carolinas, LLC (DEC) as Director of Customer Regulatory Planning, Support, and Compliance. DEC is a subsidiary of Duke Energy Corporation (Duke Energy) which provides various services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy.

Q. **PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.**

A. I obtained a bachelor’s degree in Marketing Management from Virginia Tech’s Pamplin College of Business and a Master of Business Administration degree from East Carolina University’s Thomas D. Arthur Graduate School of Business. My career began in banking and finance and then I shifted into a leadership role for a regional chamber of commerce and economic development organization. In 2016, I transitioned to the utility industry joining American Electric Power (AEP) where my roles included business development, economic development, community relations, and state government affairs for the Kentucky operations. I joined Duke Energy in 2018, having held roles within Stakeholder Engagement and Renewable Strategy and Policy, before assuming my current position in Customer Services in 2020.

Q. **PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR OF CUSTOMER REGULATORY PLANNING, SUPPORT, AND COMPLIANCE.**

A. My responsibilities include oversight and execution of key customer initiatives, regulatory compliance and reporting, and audit and compliance within Customer Services. I provide direction and leadership as business plans are developed to support the goal of increasing customer satisfaction.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THESE PROCEEDINGS?

A. The primary purpose of my testimony is to highlight Duke Energy Kentucky's excellent service to our customers and to describe how that translates to customer satisfaction. To that end, I describe the Company's customer initiatives and discuss the Company's customer satisfaction program and measurements. In addition, I describe the various ways the Company serves and supports our customers, especially the unique needs of our low-income customers. Finally, in keeping with hearing our customers' concerns and providing excellent customer service, I discuss the Company's proposal to expand the fee-free payment options available to residential customers to include payments by debit, credit, prepaid cards, and electronic check (collectively, Card Payments), which will provide them with more flexibility in their bill payments. I sponsor Schedule D-2.26 in satisfaction of FR 16(8)(d).

II. OVERVIEW OF CUSTOMER SERVICES

Q. PLEASE DESCRIBE HOW THE COMPANY VIEWS CUSTOMER SERVICE.

A. At Duke Energy Kentucky, the customer is at the center of our purpose. Evolving customer expectations, emerging technologies, and changing public policies all converge to create a dynamic environment for the Company and the industry. Duke Energy Kentucky strives to exceed customer expectations through building genuine connections with its customers by soliciting customer feedback, taking note of evolving customer expectations, anticipating customer needs, leveraging emerging technologies, and offering dynamic solutions to customer issues. Customer service is a major factor in Company policies, programs, and decisions, and is at the forefront of our mission to provide safe and reliable service to all of our customers.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S CUSTOMER EXPERIENCE AND SERVICES FUNCTIONS.

A. Duke Energy Kentucky's customer experience and services functions are comprised of multiple departments responsible for developing and executing policies, processes, and procedures to engage with our customers across multiple communication channels. The primary channels our customers use to interact with us are Duke Energy's website (including recently launched live agent chat), mobile app, phone, email, social media (Facebook, Instagram, LinkedIn, and X), and face-to-face interactions. The organization includes customer contact center operations, customer experience, customer technologies, metering services, complaint resolution, billing and payment processes, and credit and collections activities.

Q. PLEASE DESCRIBE THE COMPANY'S CUSTOMER CONTACT CENTER OPERATIONS.

A. Our contact center operations are designed and continuously enhanced to strive to answer customer inquiries efficiently and accurately. During normal business hours, a combination of remote, on-site, and vendor customer care specialists are available to process and support inbound and outbound calls, live web chat, emails, mailed letters, faxes, and social media inquiries from Duke Energy Kentucky's non-residential and residential customers. Additionally, customer care specialists are available outside of normal business hours to support outage or emergency calls.

Q. DOES THE COMPANY RECOGNIZE THE DIVERSE NEEDS OF ITS CUSTOMER BASE WHEN PROVIDING CUSTOMER SERVICE?

A. Yes. In addition to our primary responsibility of providing safe and reliable electric service, we understand that our customer base has diverse service needs and strive to recognize and accommodate them where possible. For example, Duke Energy employs Account Managers that are assigned to our large, complex customer accounts to answer questions, provide solutions, and resolve issues. These Account Managers work to foster positive relationships, focusing on the specific and often complex power needs of commercial, industrial, and governmental customers. They serve as a single point-of-contact, providing consistency and a level of understanding of the customer's business interests and challenges. This familiarity allows our Account Managers to manage the customer relationship to enhance customer satisfaction by helping to develop and recommend personalized options in areas such as service delivery, renewables, energy efficiency, and demand response programs.

The Company's Business Service Center (BSC) is focused on providing a service model customized by business segment for our small and medium business (SMB) customers. This organization positions us to better understand and support the many different types and needs of business customers. Our BSC support teams offer dedicated phone numbers, email addresses, and digital experiences so SMB customers can utilize the channel that works best for them.

One business segment supported within the BSC includes builders, developers, multi-family builders, and local inspecting authorities, all of which play important roles for new home construction. The Company recently improved this segment's customer experience through a digital tool called the Builder Portal. The Builder Portal is designed to improve customer experience when submitting work orders, requesting status updates, or seeking online support. Providing dedicated teams specializing in new construction and offering multiple contact channels allows us to better serve this business customer segment and provides options that best suit their needs.

Additionally, within the BSC are the Business Experience (BEX) and Renewable Service Center (RSC) teams. The BEX team provides dedicated support to businesses with one to seven accounts, and the RSC services inquiries related to solar installations and billing options. These teams help customers set up their accounts, answer questions on features, and make changes so they can utilize the convenient, self-service options at their convenience. We also offer these customers dedicated phone numbers, email addresses, and digital experiences so they can utilize the contact channels that work best for them. And, with the deployment of the Company's current customer information system, Customer Connect, those digital experiences were enhanced through the Business and Landlord Portals. The Business Portal allows business customers to easily manage their business account online. The Business Portal is a one-stop digital resource providing customized tools and self-service options that allow customers to streamline bill payment, view and track energy usage, and keep designated people in the know by allowing multiple user logins. The Landlord Portal allows property managers or owners ways to easily manage rental energy accounts all in one place. The Landlord Portal provides all the benefits of the Business Portal, plus additional features designed to meet the specific account needs of property managers.

The Company continuously explores ways to improve the customer experience for all customers. For example, for residential customers, we offer a variety of billing and payment choices, including paperless billing, Pick Your Due Date, Budget Billing, and we are proposing in this case to expand our fee-free payment options to make paying bills even more simple, secure, and convenient. We share important information with our customers through monthly bill inserts, texts, and/or emails, and offer programs and tips to help protect customers from high energy bills due to extreme temperatures.

Additionally, we supply customers with ways to protect themselves from utility scammers through dedicated communications, webpages, and a Scam

Reporting Tool. The Scam Reporting Tool allows customers to share their experiences with attempted scams and solicits information we can utilize to help protect other Duke Energy customers.

III. TRANSFORMING THE CUSTOMER EXPERIENCE

Q. PLEASE DESCRIBE THE COMPANY'S EFFORTS TO ENHANCE THE CUSTOMER EXPERIENCE THROUGH DIGITAL CHANNELS AND TECHNOLOGIES.

A. The Company continues to experience increased interest in and adoption of digital communication and service channels. With the rapid transformation of technology, customer expectations surrounding technology are increasing at an accelerated rate, and our teams work to provide an easy-to-use, straightforward digital experience to meet customer expectations.

Mobile Application and Web Portal

The Company's digital transformation efforts help us deliver customer benefits, including advanced capabilities and offerings. The Company's free mobile application (Mobile App) offers residential and most small business customers ways to easily manage their account and monitor daily usage from anywhere in the United States. The Mobile App was developed, and continues to be enhanced, based on customer feedback, with the most requested features being the ability to view and pay bills, report an outage, enroll in billing and payment programs, view billing history, monitor energy usage, receive personalized offers, and receive outage restoration updates. The Mobile App also provides links to some of our most-used account management service features, such as customer requests to start, stop, and move their electric service. Mobile App log-in is streamlined with the web portal by using the same customer log-in for both and offers the option to use fingerprint or facial recognition for a fast, secure sign-in if a customer's device supports biometrics. Last year, a new enhancement to the Mobile App was released to customers, the chatbot. The chatbot remediates navigation confusion, answers frequently asked questions, and provides access to external features. For example, the chatbot directs customers to the Duke Energy website for additional information or the authenticated space for certain account-specific features. The Mobile App team recently won an industry award for the development of its chatbot.

The Company's Web Portal has remained a key digital channel for customers to manage their accounts online, with the functionality to easily and conveniently pay their monthly bill, set up auto-pay, update accounting information, and start, stop, or transfer service. Customers can also track their energy usage over time, which can help them understand consumption patterns and make informed decisions for how to efficiently manage their energy usage.

Overall, the Mobile App and Web Portal are increasingly critical channels for customers to interact with the Company. Digital channels enable real-time communication and interactions between customers and Duke Energy. The top digital interactions include payment, outage, and service inquiries. So far this year, customers have leveraged the digital channels to make more than 200 thousand payments. The outage reporting allows customers to report outages, receive updates on service restoration, and access customer support more efficiently through the Outage Alerts program and online Outage Map. Throughout 2023 and 2024, approximately 250,000 Outage Alerts were sent to Kentucky customers.

Live Chat

Last year, the Company enhanced the online Web Portal to pilot the functionality for a customer to chat live with a customer service specialist. The chat icon is visible to customers during business hours when a specialist is available. After validating a customer's account information, the customer is routed to a specialist to complete their request. Since the launch of live chat in July 2023, more than 3,000 successful live chat sessions have been handled by the Company, primarily related to billing and payment questions. Based on the success of the pilot, including positive customer feedback, the Company made live chat a permanent option for customers in February 2024.

In addition, the functionality of live chat was recently enhanced to enable account identification to customer service specialists automatically based on web login credentials and to integrate frequently asked questions. This function passes the customers' account information to the specialist to serve the customers' needs more efficiently.

Integrated Voice Response

Like our digital channels, customers can seamlessly self-serve through our voice channel via Integrated Voice Response (IVR). The key technology enabling self-service for customer calls is the Company's advanced language IVR system. So far in 2024, the IVR has contained over 60% of the calls to the Company, meaning customers efficiently self-served, saving time for the customers and providing customer service agents time to serve other customers. Self-service functionality, such as requesting a payment arrangement and reporting a power outage, can be done through voice-activated prompts, helping to provide a more positive customer experience. There are also self-serve options for customers to enroll in, or withdraw from, Budget Billing, add their card information to Speedpay wallet for easy access, update their account's phone number, and request their account number. Another feature of IVR is First-in- Line, which allows customers to either remain on hold or select a call back number in busier than normal call volumes, where they can be reached when a service representative becomes available.

With capabilities provided by Customer Connect and new enhancements to the IVR, we can better connect with customers through texting experiences. Customers can receive texts with additional options and links and even respond to receive more options. For example, if a bill reminder is texted and a customer responds saying they are not able to pay by the due date, the system can recognize that message and provide options or a link to set up an installment plan.

IV. LOW-INCOME CUSTOMER SUPPORT

Q. HOW DOES DUKE ENERGY KENTUCKY WORK TO SUPPORT ITS LOW-INCOME CUSTOMERS?

A. As discussed by Witness Spiller, support for low-income customers is a priority for Duke Energy Kentucky. In recent years, the Company has recognized that utility assistance agencies serve as a critical channel for customers to receive support. The Company continues to leverage its Agency Team that is a dedicated single point of contact for these utility assistance agencies. The Agency self-service portal also continues to be available for agencies to conveniently and more efficiently view pledge history on customers' accounts to make more informed pledge decisions and receive notification of pledge expiration to ensure their commitments are satisfied. The success of the Agency Team is evidenced by the more than $3.5 million in assistance funds that Duke Energy Kentucky customers have received over the last two years.

The Company's Share the Light Fund (STLF) is another way that Duke Energy continues to aid qualifying customers who are struggling to pay their gas and electric bills. Share the Light Fund contributions are received from employees and customers, as well as Duke Energy shareholders. Each year, Duke Energy contributes $25,000 and will match dollar for dollar up to $25,000 in customer contributions. The Share the Light Fund is administered in partnership with the Northern Kentucky Community Action Commission (NKCAC) using federal low-income guidelines, as well as need, to determine program eligibility.

Additionally, the Company offers the Home Energy Assistance (HEA) program that provides another source of monthly bill assistance for eligible customers whose income is up to 200 percent of the federal poverty level. Electric or combination electric and natural gas customers can receive up to $99 per month between January-April and July-September through the subsidy component and up to $400 is available for immediate assistance through the crisis component for customers who have a past-due balance and/or are in danger of disconnection. This program is funded through a combination of customer charges and $50,000 in shareholder contributions, and managed by Community Action Kentucky, Inc., and locally, its subcontractor, the NKCAC.

The Neighborhood Energy Saver Program (NES) is an energy efficiency initiative for low-income customers. This program allows for the installation of energy efficient measures in a customer's home to reduce energy consumption. These measures include attic insulation, air sealing, duct sealing, and smart thermostats. NES generated installations of energy efficient upgrades in more than 480 homes in the 2023 – 2024 program fiscal year.

Additionally, the Payment Plus program is available to qualifying residential customers and provides the opportunity to receive a $500 reduction on their utility bill. This program is coordinated by the NKCAC and customers are able to earn the reduction on their utility bill by participating in three activities at no cost to them. Through participation in the program, customers will learn how to control their energy bills, receive money-saving tips for balancing their budget and can have their home weatherized. The Company partners with People Working Cooperatively (PWC) to aid in its Weatherization Program that aims to help qualifying customers save energy and decrease expenses through the implementation of energy-saving measures in their homes. In the 2023-2024 program year, nearly 100 Duke Energy Kentucky customer homes received weatherization services.

Q. DOES THE COMPANY OFFER ANY SUPPORT FOR MEDICALLY VULNERABLE CUSTOMERS?

A. Yes, the Company has protections in place for medically vulnerable customers through its medical certificate and life support programs. The medical certificate program extends the disconnection date by seven days up to two times per year for a customer whose medical provider determines that electricity is needed due to a medical condition. The Life Support program is available to customers annually upon providing the Company a medical provider's indication that someone in the home has medically essential equipment and the loss of power would be detrimental to the person's health. The Company takes additional steps (*e.g.*, personal phone call or premises visit) to work with customers enrolled in the Life Support program prior to planned power outage scenarios and potential disconnections for non-payment. The Company will perform a site visit on the day of planned disconnection and will not disconnect service without first speaking with the customer or their authorized representative in-person or over the phone. While these programs do not credit customer bills, they help provide insight into the fact that the Company takes additional care for medically vulnerable customers to ensure proper notification and protections are in place to help them make arrangements to continue their electric service.

V. CUSTOMER SATISFACTION

Q. HOW DOES THE COMPANY SEEK TO MEASURE EXCELLENCE IN CUSTOMER SERVICE?

A. We recognize that customer expectations continuously evolve and that it is critical we hear and understand the "Voice of the Customer" to improve overall customer satisfaction (CSAT). To that end, we operate a robust CSAT program, which includes both national benchmarking studies and proprietary relationship and transactional CSAT studies. We analyze results from these studies in monthly data review sessions, with findings driving improvements to processes, technology, and behaviors, all to continuously improve the customer experience.

As discussed by Witness Spiller, we measure overall customer satisfaction and perceptions about the Company through an ecosystem of measurement tools. One of these tools is the CX Monitor survey that is sent annually to all residential, SMB customers, and large business customers for whom we have a valid email address. Customers are asked to provide feedback regarding their overall sentiment as well as satisfaction with key experiences they have had with the Company over the past twelve months. Examples of these experiences include billing and payment and power quality and reliability. Customers rate overall sentiment and key experience satisfaction on a ‘0-10’ scale, while also providing open-ended verbatim comments detailing the primary reasons for their score.

In addition to our CX Monitor survey, we use Fastrack 2.0, a proprietary, post-transaction CSAT measurement program. Fastrack 2.0 measures customer satisfaction with recent interactions customers have had with the Company. Fastrack 2.0 was intentionally designed to complement the CX Monitor survey and provide greater insight into experiences that matter to our customers and near real time feedback to our front line, customer-facing employees. The survey questions cover the customer experience regarding completed field work, including requests to start and transfer electric service, repair outdoor lights, and restore outages. Analysis of these ratings helps to identify specific service strengths and opportunities that drive overall satisfaction and to provide guidance for the implementation of process and performance improvement efforts. Last year alone, Duke Energy Kentucky collected more than 1,500 residential Fastrack 2.0 surveys.

We also implemented Reflect, a post-contact survey that offers customers the opportunity to provide immediate feedback after they contact us by web, call to the automated system, or call to a live agent. This tool provides critical feedback to help improve the channels customers use when interacting with us. Through September 2024, the Reflect program has collected more than 5,100 Duke Energy Kentucky responses, with 75% of customers on average providing the highest satisfaction ratings (‘9’ or ‘10’ on a ‘0-10’ point scale).

Finally, while we have focused internally on our proprietary Voice-of-Customer data to inform areas of focus and our actions, we continue to rely on J.D. Power to provide a benchmark of our performance compared to other utilities as J.D. Power’s Customer Satisfaction Index is a critical measure of a company's success. Duke Energy Midwest (which includes Duke Energy Kentucky, Duke Energy Indiana, and Duke Energy Ohio) recently saw impressive results in the 2023 J.D. Power Electric Utility Residential Customer Satisfaction Study, finishing above the Midwest Region average and in the second quartile among large utilities nationally.

Q. HOW DOES A CUSTOMER BRING AN ISSUE TO THE COMPANY’S ATTENTION?

A. Our customers have multiple channels to voice an issue, including through our customer care team, engaging on social media platforms, our website, email, through our employees, or utilizing our Ethics line. Additionally, as previously mentioned, CX Monitor and Fastrack are two key proprietary surveys we use to continually monitor and track customer feedback. At the end of each survey, customers are invited to share additional comments regarding any outstanding questions they have for us that still need to be answered or issues that still need to be resolved. These comments are converted into high priority "Hot Alerts" and forwarded to the Consumer Affairs team for resolution, with a member of our customer service staff personally contacting the customer to ensure satisfactory resolution to the customer's question or issue. Separately, a Hot Alert may be triggered by an automated keyword software review of survey statements, which may indicate potential customer frustration or a negative experience, even if the customer did not directly ask for follow up.

Furthermore, customers raise issues and inquiries directly with our employees. Our employees can then use the "I Can Help" tool to report the concern, kickstart the resolution process, and track it to completion. While the Company remains committed to gathering feedback from customers through various survey instruments, we are also making it easier for customers to contact us, receive assistance, follow-up, and resolution. Most importantly, we are leveraging innovative tools to proactively address issues and reduce complaints and complaint escalation from customers.

Q. HOW DOES THE COMPANY UTILIZE THE RESULTS FROM ITS MEASUREMENT TOOLS?

A. The ecosystem of measurement tools described above was intentionally designed to understand what is working well from a customer perspective and to identify opportunities to improve the customer experience. Actual performance metrics, overall CX Monitor perceptions, Fastrack 2.0 ratings, Reflect feedback, J.D Power industry CSAT benchmarks and trends, and customer complaints and feedback, all work in concert to assist the Company in targeting areas for improvement and enhancement. By way of example, the program proposals and discussed improvements set forth in my testimony are born from the Company's measurement tools ecosystem.

VI. LATE PAYMENT CHARGE

Q. EXPLAIN THE PURPOSE OF THE COMPANY'S LATE PAYMENT CHARGE IN BILL COLLECTION.

A. The late payment charge plays an important role in the bill collection strategy and is only imposed on late-paying customers to counteract the cost of collecting the liability. The fee serves as a method to encourage timely customer payments and assists in managing the overall financial burden on all customers that occurs from collection costs, including the carrying costs of unpaid bills, outbound customer delinquency communications, and customer service costs.

Q. WHAT IS THE COMPANY'S LATE PAYMENT CHARGE CURRENTLY?

A. In 2022, the Company received Commission approval to reduce the late payment charge by more than half, from 5 percent down to 2.3 percent of the amount past due.

Q. DOES THE COMPANY OFFER ANY LATE PAYMENT WAIVER PROGRAMS?

A. Yes, for customers who receive an authorized agency assistance pledge, the Company waives any late payment charge for the current bill for which the pledge is received. An authorized agency is an organization in Kentucky that administers federal Low-Income Home Energy Assistance Programs and/or the Home Energy Assistance Programs that are offered by Duke Energy Kentucky.

VII. FEE FREE PAYMENT PROPOSAL

Q. IS THE COMPANY PROPOSING ANY NEW CUSTOMER-RELATED PROGRAMS OR CHANGES TO EXISTING PROGRAMS?

A. Yes. The Company is proposing one new customer program that will alleviate the most frequently expressed payment-related frustration of residential customers: payment fees. The program would expand the available fee-free payment options to now include payments by debit, credit, prepaid cards, and electronic check (collectively, Card Payments).

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT FEE-FREE PAYMENT OPTIONS AND EXPLAIN WHY THERE ARE NO FEES ASSOCIATED WITH THOSE OPTIONS.

A. Currently, the Company accepts residential customer payments through check, money order, cash (via some walk-in payment locations), automated bank drafts, and Electronic Funds Transfer without fees. The costs for the Company to offer these payment methods are built into the cost of service, paid for by all customers, and are not recovered exclusively from those specific customers that use these methods of payment.

Q. DOES THE COMPANY EXPECT THE PROGRAM TO MAKE PAYMENT OPTIONS MORE INCLUSIVE FOR ALL RESIDENTIAL CUSTOMER SEGMENTS?

A. Yes. Expanding the available fee-free payment options to include Card Payments would make payment options more inclusive for all residential customers. It is important to ensure that all residential customers, regardless of how their own income is received, have access to convenient methods to pay their utility bill without a frustrating or burdensome fee. For example, prepaid and reloadable debit cards are becoming more prevalent as workers' paychecks, Social Security benefits, tax refunds, Medicare benefits, and unemployment benefits are being distributed via these card types. Prepaid card utilization is growing more quickly than debit or credit,[1] and these customers should not be isolated from fee-free options simply because a loadable card is utilized by an employer for payroll, a governmental agency to issue benefits, or the customer is unbanked or underbanked. Additionally, fee-free Card Payments are important to some of the most vulnerable customers. For example, 49% of the Company's agency assistance recipients utilized the Card Payment channel at least once over the past six months compared to only 19% of non-recipients. As we learn more about our customers' payment needs, it is apparent that customers would benefit and be more satisfied with the ability to make their payments without incurring additional fees.

Q. HAS THE COMPANY MADE ANY RECENT ADDITIONS FOR FEE-FREE PAYMENT OPTIONS?

A. In September 2024, the Company began offering fee-free payments at 16 walk-in payment locations within Kroger supermarkets in order to be more inclusive with payment offerings. Customers continue to request additional fee-free payment options, and fee-free card payments will further expand these options for customers to make payments without a fee.

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[1] According to the Federal Reserve Payments Study: 2022 Triennial Initial Data Release, prepaid debit card payments had the greatest growth rate by number (9.6% per year), reaching 18.1 billion payments in 2021. *See* The Federal Reserve Payments Study: 2022 Triennial Initial Data Release, available at https://www.federalreserve.gov/paymentsystems/2023-April-The-Federal-Reserve-Payments-Study.htm (last accessed Nov. 19, 2024).

Q. PLEASE DESCRIBE THE TRANSACTION FEE CURRENTLY ASSOCIATED WITH CARD PAYMENTS AND HOW THOSE FEES ARE COLLECTED.

A. If a residential customer wants to make a Card Payment, there is currently a $1.25 (recently lowered from $1.50) transaction fee collected in order to do so. The transaction fees associated with Card Payments are collected by the third-party directly from the customer at the time of transaction.

Q. HAVE THE COMPANY'S RESIDENTIAL CUSTOMERS REQUESTED CARD PAYMENTS TO BE FEE-FREE?

A. Yes. The requirement to pay a transaction fee when making a Card Payment for utility service is one of the largest frustrations a customer experiences when paying their Duke Energy Kentucky bill. Card Payments are also a necessary method of payment by many customers which makes the imposition of the per transaction fee increasingly dissatisfying. Few industries charge a per transaction fee for Card Payment processing and customers have grown accustomed to paying for other life necessities without a separate, additional fee. For example, the feedback received in the Company's recent residential surveys shows that many customers note that payment fees are what they liked least about their billing and payment experience:

- *"Most companies that offer online payment as a convenience to their customers don't charge a fee. You should not charge a fee."*
- *"The $1.50 fee is not good. [Convenience] to pay a bill should not cost!"*
- *"I have a flex account through my insurance and I would like to be able to pay bill without paying a fee."*

A significant number of additional comments related to card payment fee frustrations from Kentucky customers are included in Attachment JSC-1.

Q. HAS THE COMPANY MADE ANY EFFORTS TO MAKE THE CARD PAYMENT CHANNEL MORE AFFORDABLE?

A. Yes. Earlier this year, residential customers saw a reduction in the Card Payment fee to one of the lowest in the industry. Through the Company's successful renegotiation with the third-party credit card payment processor, Speedpay, the third-party fee was reduced by 17% for residential customers, from $1.50 to $1.25 per residential transaction.

Q. DOES THE COMPANY RECEIVE ANY PORTION OF THE CONVENIENCE FEES?

A. No, the Company does not receive any portion of the convenience fees.

Q. WILL DUKE ENERGY KENTUCKY STILL OWE SPEEDPAY THE CARD TRANSACTION FEES?

A. Yes, under the expanded fee-free proposal, Duke Energy Kentucky would pay the $1.25 per transaction fee for Card Payments to the third-party credit card payment processor, Speedpay.

VIII. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE SCHEDULE D-2.26.

A. Schedule D-2.26 is an adjustment to reflect expenses related to Card Payment fees. The adjustment increases operating expense in the forecasted test period by $319,314.

Q. DID THE COMPANY CONSIDER POSSIBLE COST SAVINGS AS A RESULT OF CUSTOMERS WHO MAY SWITCH TO CARD PAYMENTS FROM OTHER PAYMENT CHANNELS?

A. While it is possible that transactions beyond the forecasted amounts will occur with Commission approval for the fee-free Card Payment option, the Company has opted for a conservative approach. The Company incorporated the Card Payment fees in the revenue requirement by utilizing actual card transaction counts through September 2024 and annualizing the remaining months of the year to forecast 2025 and 2026 channel usage. The Company is not adjusting its revenue requirement to account for changes related to possible payment channel switching and thus we are also not adjusting the revenue requirement related to other payment channel processing costs.

IX. CONCLUSION

Q. WERE SCHEDULE D-2.26 AND ATTACHMENT JSC-1 PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR CONTROL?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

Sample of 2023 and 2024 Customer Survey Comments Regarding Card Payment Fee

- *"Convenience fee" is unnecessary.*
- *$1.50 fee is ridiculous*
- *Again I don't think there should be a service fee to pay online because everything is online these days.*
- *Credit card fees should go away*
- *Do not like processing fees*
- *Do not like the "convenience fee".*
- *Don't enjoy paying a fee for speed pay*
- *Don't charge customers a fee to pay online.*
- *Don't like that you have to pay a fee.*
- *Don't like the additional processing fee that is charged.*
- *Don't like the credit card payment fees*
- *Duke Energy is the only company we do business with that charges a fee to pay bills online!*
- *Duke website charges a service fee for paying your bill.*
- *Easy app experience, I don't like the service fee to pay using a card. Seems excessively expensive.*
- *Easy to use, just hate paying a fee to pay online.*
- *Extra fees for credit card processing. Its just something else to bill people for.*
- *Fees are annoying when paying online.*
- *Forced to pay an extra fee to use service.*
- *Hate that you have billing fees to pay when paying on line.*
- *I do not like the fee that I have to pay everytime that I pay online. It should not be a fee to pay your bill, especially when you are paying on time or early.*
- *I do not like the transaction fees for payments through mobile app.*
- *I don't believe there should be a fee to pay your bill.*
- *I don't like having to [pay] a fee, but other than that it's easy!*
- *I don't like that your credit and debit payments charge fees. There are plenty of other companies that allow this option free of charge. Otherwise, great experience.*
- *I don't like the fact that you charge a fee to pay online.*
- *I don't like the processing fee.*
- *I don't like to pay the extra fee when I paid online.*
- *I don't understand the online service fee!*
- *I just don't like paying the extra fee for credit cards.*
- *I like to use a credit card to pay, don't like that I'm charged a fee every time.*
- *I love paying it online just hate the fees*
- *I pay online using the Duke Energy website. I don't like having to pay the fee for this service.*

- *I shouldn't have to pay a credit card fee to pay my bill.*
- *I sometimes pay online using the Duke web site but there is a fee to pay on line. There should never be a fee for that convenience.*
- *I suggest removing credit card fees from online payments. I would love to get away from pay by mail.*
- *I wish there was no credit card fee*
- *I would like to pay [with] a credit card without [paying] and extra fee as long as I am [paying] early or on time.*
- *Not sure why there is a processing fee*
- *Online/App Portal to pay is easy to use. The extra fees to use a credit card are annoying.*
- *Paying a fee to pay my bill with my debit card is ridiculous*
- *Paying online there's a fee of 1.50 I don't think there should be a fee*
- *Prefer not to pay a credit card processing fee*
- *Remove the fee for paying online*
- *Service fees for paying online…????*
- *Stinks to pay a fee to use a debit card*
- *The 1.50 fee should be waived if paying in full*
- *The convenience fee is annoying.*
- *That fact I have to pay a fee to use my card is absurd*
- *The fee for online payment seems unnecessary.*
- *The fee isn't great when using CC*
- *We would rather pay online but don't like the fee to do so.*
- *Website is easy to use but we shouldn't be charged a fee.*
- *Wish the fee for using a credit card was gone.*
- *Would be nice if there wasn't a fee for using a credit card.*
- *Would like to pay by credit card without the extra fee.*

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. 2024-00354

DIRECT TESTIMONY OF

THOMAS J. HEATH, JR.

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 2, 2024

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Thomas J. Heath, Jr. and my business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS) as Corporate Finance Director. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Science degree with a major in Accounting from Southeastern Louisiana University and a Master of Arts degree in Theology from Saint Leo University. I am a Certified Public Accountant licensed in the Commonwealth of Kentucky. My professional work experience began in 1995 with the public accounting firm of Price Waterhouse (now PricewaterhouseCoopers), where my work focused on audits of Generally Accepted Accounting Principles (GAAP) and Securities and Exchange Commission (SEC)-compliant financial statements, including those in the electric utility industry, and the performance of due diligence procedures over mergers and acquisitions. In April 2004, I joined Cinergy Corp. (a predecessor company to today's Duke Energy) as a Lead Analyst in the Accounting Research Group where I was responsible for assessing the appropriate accounting and disclosure treatment for significant non-routine matters as well as certain regulatory accounting interpretations.

Over the next 10 years, I held various finance-related positions of increasing responsibility. In August 2014, I accepted a position in Duke Energy's Treasury Department and for the last 10 years have held the positions of Corporate Finance Director and Structured Finance Director for different periods of time. During my time in treasury, I have been responsible for executing public debt offerings for Duke Energy and its utility subsidiaries, including utility cost recovery bond issuances; managing Duke Energy's Master Credit Facility; providing support for regulatory proceedings for Duke Energy's utility subsidiaries; managing Duke Energy's interest rate risk management program; executing various project debt financings for Duke Energy's nonregulated renewable portfolio; and leading the due diligence process for Duke Energy's Transaction and Risk Committee.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS CORPORATE FINANCE DIRECTOR.

A. I am primarily responsible for financing the operations of and providing support for regulatory proceedings for Duke Energy's Midwest utility subsidiaries, including Duke Energy Kentucky, and managing Duke Energy's interest rate risk management program.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes. I previously provided rebuttal testimony before the Commission in Case No. 2022-00372.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THESE PROCEEDINGS?

A. My testimony will address Duke Energy Kentucky's financial objectives, capital structure, and cost of capital. I will also discuss the current credit ratings and forecasted capital needs of Duke Energy Kentucky. Throughout my testimony, I will emphasize the importance of Duke Energy Kentucky's continued ability to meet its financial objectives and the benefits to customers resulting from Duke Energy Kentucky maintaining financial stability and strong credit ratings.

I sponsor the following information that I used in preparing my financial forecasts in this case: Duke Energy's dividend policy; Duke Energy Kentucky's debt rate assumptions; existing short-term and long-term debt balances; capital lease and equipment lease information; and information relating to long-term debt financing.

I sponsor Filing Requirements (FR) FR 12(2)(a), FR 12(2)(b), FR 12(2)(c), FR 12(2)(d), FR 12(2)(e), FR 12(2)(f), FR 12(2)(g), FR 12(2)(h) and FR16(7)(j), FR 16(7)(l) and FR 16(7)(r). I sponsor Schedules J-1, J-2, J-3, and J-4 in response to FR 16(8)(J). Finally, I provided certain information to Duke Energy Kentucky witness Mr. Grady "Tripp" S. Carpenter for his use in preparation of FR 16(7)(h) and Schedule K in response to FR 16(8)(k), respectively.

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. Duke Energy Kentucky continues to face substantial capital needs over the next several years. The Company competes for capital in the open market and must appeal to debt and Duke Energy's equity investors to attract the capital it needs.

Investors have a variety of investment opportunities available to them and require a return commensurate with the risk they incur. They will invest elsewhere if they feel the expected return provided by a company is inadequate, and lower credit quality weakens a company's attractiveness as an investment opportunity relative to companies with higher credit quality and similar return profiles. For this reason, it is critically important that the Company maintain strong, investment-grade credit quality to assure its financial strength and flexibility and ensure access to capital on reasonable terms.

The Company is making significant capital investments to provide cost-effective, safe, reliable and increasingly cleaner electric service to its customers well into the future. The Company's proposed rate increase will allow it to recover prudently incurred costs, compete in the capital markets for needed capital, and preserve its financial standing with both equity and debt investors as well as the credit rating agencies, to the long-term benefit of customers.

II. DUKE ENERGY KENTUCKY'S FINANCIAL OBJECTIVES

Q. WHAT ARE DUKE ENERGY KENTUCKY'S FINANCIAL OBJECTIVES?

A. The Company at all times seeks to maintain its financial strength and flexibility, including its strong investment-grade credit ratings, thereby ensuring reliable access to capital on reasonable terms. Financial strength and access to capital are necessary for Duke Energy Kentucky to provide cost-effective, safe, and reliable service to its customers. Specific targets that support financial strength and flexibility include: 1) maintaining an equity component of the capital structure that is supportive of Duke Energy Kentucky's credit quality; 2) ensuring timely recovery of prudently incurred costs; 3) maintaining sufficient cash flows to meet obligations; and 4) maintaining a sufficient return on equity to fairly compensate shareholders for their invested capital. The ability to attract capital (both debt and equity) on reasonable terms is vitally important to the Company and its customers, and each of these targets help the Company meet its overall financial objectives.

Q. PLEASE EXPLAIN HOW DUKE ENERGY KENTUCKY'S CUSTOMERS WILL BENEFIT FROM DUKE ENERGY KENTUCKY ACHIEVING ITS CREDIT RATING OBJECTIVES.

A. The benefits of achieving and maintaining strong, investment-grade, credit ratings include lower overall financing costs and greater access to the capital markets, thus improving Duke Energy Kentucky's ability to maintain a safe, reliable, and low-cost level of service. Duke Energy Kentucky's ability to access needed capital on reasonable terms is supported by the following specific objectives of the Company: (a) maintaining a strong equity component in its capital structure; (b) pursuing timely recovery of prudently incurred costs of providing utility service; (c) maintaining sufficient cash-flows to meet its obligations; and (d) maintaining an adequate rate of return on common equity.

Q. WHAT RATEMAKING TREATMENT IS BEING REQUESTED IN THIS PROCEEDING AND HOW WILL THE COMPANY'S FINANCIAL OBJECTIVES BE IMPACTED?

A. As explained by Duke Energy Kentucky witness Amy B. Spiller, Duke Energy Kentucky is requesting an overall increase of approximately $70 million. As part of this request, supported by the analysis and testimony of Duke Energy Kentucky witness Mr. Joshua C. Nowak, the Company is requesting an allowed return on equity (ROE) of 10.85 percent. The proposed capital structure in this request is comprised of 52.728 percent equity and 47.272 percent debt. Approval of the Company's request in this case will support its financial objectives by ensuring timely cash recovery of its prudently incurred costs.

Q. PLEASE EXPLAIN HOW THE PROPOSED CAPITAL STRUCTURE IS REASONABLY BALANCED SO IT DOES NOT OVER BURDEN CUSTOMERS TO THE BENEFIT OF SHAREHOLDERS.

A. The proposed capital structure represents an appropriate amount of risk due to leverage while minimizing the weighted average cost of capital for customers. Approval of the proposed capital structure will help Duke Energy Kentucky maintain its credit quality, the importance of which I will describe in subsequent sections of my testimony and is consistent with Duke Energy's target credit ratings for Duke Energy Kentucky.

III. CREDIT QUALITY & CREDIT RATINGS

Q. PLEASE EXPLAIN CREDIT QUALITY AND CREDIT RATINGS, AND HOW THEY ARE DETERMINED.

A. Credit quality (or creditworthiness) is a term used to describe a company's overall financial health and its willingness and ability to repay all financial obligations in full and on time. An assessment of Duke Energy Kentucky's creditworthiness is performed by Standard & Poor's (S&P) and Moody's Investors Service (Moody's), and results in Duke Energy Kentucky's credit ratings and outlook.

Many qualitative and quantitative factors go into this assessment. Qualitative aspects may include an assessment of the regulatory climate in which Duke Energy Kentucky operates, its track record for delivering on its commitments, the strength of its management team, corporate governance, its operating performance, and the strength of its service territory. Quantitative measures are primarily based on operating cash flow and focus on the level at which Duke Energy Kentucky maintains debt leverage in relation to its generation of cash and its ability to meet its fixed obligations (interest and principal payments in particular) on the basis of internally generated cash. The percentage of debt to total capital is another example of a quantitative measure. Creditors and credit rating agencies view both qualitative and quantitative factors in the aggregate when assessing the credit quality of a company.

Q. WHAT IS THE ROLE OF REGULATION IN THE DETERMINATION OF THE FINANCIAL STRENGTH OF A UTILITY COMPANY?

A. Investors, investment analysts, and the credit rating agencies regard consistent and predictable regulation as one of the most important factors in assessing a utility company's financial strength. These stakeholders want to be confident a utility company operates in a stable regulatory environment that will allow the company to recover prudently incurred costs and earn a reasonable return on investments necessary to meet the demand, reliability, and service requirements of its customers. Important considerations include the allowed rate of return, cash quality of earnings, timely recovery of capital investments, stability of earnings, and strength of its capital structure. Positive consideration is also given for utilities operating in states where the regulatory process is streamlined, the time lag in capital investment recovery is minimized through cost recovery mechanisms such as riders and trackers, and outcomes are equitably balanced between customers and investors.

Q. HOW ARE DUKE ENERGY KENTUCKY'S OUTSTANDING SECURITIES CURRENTLY RATED BY THE CREDIT RATING AGENCIES?

A. As of the date of this testimony, S&P and Moody's rated Duke Energy Kentucky's outstanding debt as follows:

Rating Agency	**S&P**	**Moody's**
Senior Unsecured Rating	BBB+	Baa1
Outlook	Stable	Stable

Ratings in the "BBB" category, such as those of Duke Energy Kentucky, are considered adequate but have less assurance of access to the capital markets in challenging market conditions than higher ratings. There are four key factors which drive the credit ratings of the electric and gas utility sector: regulatory framework, ability to recover costs and earn returns, diversification, and financial strength. A gas or electric utility in the Baa range is described by Moody's as having (i) a regulatory framework where rates are set in a manner that will permit the utility to make and recover all prudently incurred investments, (ii) a regulatory environment that is consistent and predictable, (iii) timeliness in the recovery of operating and capital costs, (iv) rates that are set at a level where attracting capital is sufficient without difficulty, and (v) adequate financial metrics.

S&P and Moody's ratings differ but are analogous. S&P modifies its ratings with the use of a plus or minus sign to further indicate the relative standing within a major rating category. For example, a "BBB+" credit rating is at the higher end of the "BBB" credit rating category and a "BBB-"is at the lower end of the category. Moody's credit rating assignments use the numbers

"1", "2" and "3", with the numbers "1" and "3" analogous to a "+" and "-", respectively. For example, Moody's credit ratings of "Baa1" and "Baa3" would be analogous to "BBB+" and "BBB-" credit ratings at S&P.

The ratings outlook assesses the potential direction of a long-term credit rating over an intermediate term (typically six months to two years). Duke Energy Kentucky's "Stable" outlook at S&P and Moody's is an indication the credit ratings are not likely to change at this time, however a change in outlook or rating could occur if the Company experiences a change in its business, regulatory or financial risk.

Q. HAVE THERE BEEN ANY RECENT CHANGES TO DUKE ENERGY KENTUCKY'S CREDIT RATINGS OR OUTLOOKS AT S&P OR MOODY'S?

A. On May 13, 2024, Moody's affirmed Duke Energy Kentucky's Baa1 senior unsecured rating and changed its outlook to "stable" from "negative." In its May 2024 Duke Energy Kentucky report, Moody's attributed the outlook change to "the expectation that a credit supportive outcome in the utility's most recent [2022] electric rate case will support credit metrics appropriate for its Baa1 rating."[1]

On May 21, 2024, S&P affirmed Duke Energy Kentucky's BBB+ rating and stable outlook.[2]

[1] Moody's Ratings, Credit Opinion, "Duke Energy Kentucky, Inc. Update following outlook change to stable," May 13, 2024 ("May 2024 Moody's Duke Energy Kentucky Report").
[2] S&P Global Ratings, Research, "Duke Energy Kentucky Inc." May 21, 2024 ("May 2024 S&P Duke Energy Kentucky Report")

Q. DOES DUKE ENERGY KENTUCKY COMPETE FOR INVESTORS IN THE CAPITAL MARKETS? PLEASE EXPLAIN.

A. Yes. When evaluating investment alternatives, fixed income investors use a set of criteria similar to that of the rating agencies. Fixed income investors will evaluate both credit strengths and challenges to determine the overall risk of the investment. Fixed income investors make investments for up to 40 years of duration and therefore consistency and predictability of business risk including a stable regulatory environment is imperative. If the regulatory environment in Kentucky becomes unsupportive or unpredictable, investors would likely look to alternative fixed income investments that provide similar returns with lower perceived risk. In addition, if Duke Energy Kentucky's credit rating is in jeopardy, the risk of investing in the Company's debt securities would increase. In order to compensate for the increased risk, investors would require a higher rate of return. This would increase the cost of future debt issuances, which are passed through to customers. Just as the Company must compete for capital among fixed income investors in the debt capital markets, it must also be well positioned against its peers to attract equity capital. A pivotal factor in any investment decision is the risk-return profile of the subject company. Authorized ROE is of paramount importance because it sets a cap on the regulated company's ability to earn a return on invested capital and share that return with equity investors. If the Commission were to adopt an unreasonable ROE it could negatively impact Duke Energy Kentucky's ability to attract debt and equity capital on reasonable terms, especially in times of financial stress or under volatile market conditions.

Q. WHAT BENEFITS DO CUSTOMERS OF DUKE ENERGY KENTUCKY ENJOY BY BEING A PART OF THE BROADER DUKE ENERGY FAMILY?

A. Customers enjoy several benefits derived from Duke Energy Kentucky's status as a subsidiary of the larger Duke Energy enterprise. Duke Energy's $9.0 billion Master Credit Facility and $6.0 billion commercial paper program provide Duke Energy Kentucky greater access to liquidity from highly reputable financial institutions and in the short-term money markets. In addition, the Duke Energy Utility Money Pool Agreement allows Duke Energy Kentucky to borrow short-term funds from participating entities at the "AA" Industrial Commercial Paper Composite Rate, which is a lower rate than would otherwise be available to Duke Energy Kentucky as a stand-alone issuer. Access to deeper pools of liquidity at lower borrowing costs have been particularly beneficial in periods of high volatility, most recently driven geopolitical events and the uncertainty surrounding fiscal and monetary policy to address a weakening economy and decades high inflation, and prior to that the COVID-19 pandemic. Duke Energy Kentucky also benefits from lower overhead costs as a result of shared corporate services.

Q. WHAT EFFECT DO CAPITAL STRUCTURE AND RETURN ON EQUITY HAVE ON CREDIT QUALITY?

A. Capital structure and return on equity are important components of credit quality. Equity capital is subordinate to debt capital, thereby providing a cushion and safer returns for debt investors. Accordingly, equity capital is a more expensive form of capital. The Company seeks to maintain a level of equity in the capital structure that ensures high credit quality, while minimizing its overall cost of capital. An adequate ROE will allow the Company to generate earnings and cash flows to properly compensate equity investors for their capital at risk while protecting debt investors with a higher degree of credit quality. High credit quality improves financial flexibility by providing more readily available access to the capital markets on reasonable terms, and ultimately lower debt financing costs.

Q. PLEASE EXPLAIN WHY MAINTAINING CREDIT QUALITY AND CREDIT RATINGS ARE BENEFICIAL TO CUSTOMERS.

A. To assure reliable and cost-effective service, and to fulfill its obligations to serve customers, the Company must continuously plan and execute major capital projects. This is the nature of regulated, capital-intensive industries like electric and gas utilities. The Company must be able to operate and maintain its business without interruption and refinance maturing debt on time, regardless of financial market conditions. The financial markets continue to experience periods of high volatility, most recently driven geopolitical events and the uncertainty surrounding fiscal and monetary policy to address a weakening economy and decades high inflation, and prior to that the COVID-19 pandemic. Duke Energy Kentucky must be able to finance its needs throughout such periods and strong investment-grade credit ratings provide the Company greater assurance of continued access to the capital markets on reasonable terms during periods of elevated volatility. Any factors that negatively impact Duke Energy Kentucky's credit ratings, including an inadequate allowed ROE or an inadequate equity percentage of the capital structure, have the potential to reduce the Company's access to the capital markets and to increase the cost of such access.

Approval of the Company's request in this case will support its financial objectives by allowing timely recovery of its investments in plant and equipment, providing sufficient cash flows to fund necessary capital expenditures and service debt.

Q. PLEASE EXPLAIN THE CONCEPT OF FUNDS FROM OPERATIONS (FFO) AND THE IMPORTANCE OF THE RATIO BETWEEN FFO AND DEBT.

A. The Funds from Operations (FFO) to Debt calculation is a key leverage metric utilized by the credit rating agencies when determining the credit rating and rating outlook of a company such as Duke Energy Kentucky. The numerator of the equation (FFO), also referred to as Cash Flow from Operations Pre-Working Capital (CFO Pre-WC) by Moody's Investor Services (Moody's), is comprised of the operating cash flows of the company with certain proprietary adjustments made by the rating agencies. The denominator is the total debt of the company. The result of the calculation is a percentage that represents the cash flows of the company, generated annually compared to total leverage.

To maintain the current ratings by S&P and Moody's respectively, certain downgrade thresholds for this key metric have been established by the credit rating agencies for which Duke Energy Kentucky must remain above. Unfavorable regulatory outcomes will negatively impact the calculation. For example, a lower equity ratio would result in reduced FFO and higher leverage. A lower allowed ROE would also lower FFO, weakening the key metric. Moody's current rating outlook of 'Stable' for Duke Energy Kentucky reflects a credit supportive regulatory environment and the expectation that, over the next two years, the utility will demonstrate a ratio of FFO to debt in the range of 18 percent to 20 percent. Further, Moody's explains that factors that could lead to a downgrade include the ratio of FFO to Debt sustained below 17 percent, a decline in the credit supportiveness of the regulatory environment in Kentucky, or higher capital expenditures resulting in a material increase in debt levels.

Q. WHAT STRENGTHS AND WEAKNESSES HAVE THE CREDIT RATING AGENCIES IDENTIFIED WITH RESPECT TO DUKE ENERGY KENTUCKY?

A. As of the most recent publications of the Company's credit opinions, the rating agencies believe the Kentucky regulatory environment generally supports long-term credit quality with timely and sufficient recovery of prudently incurred costs and expenses, including recovery of fuel, purchased power, and environmental compliance costs, and the use of a forward test year in rate cases, which are supportive of credit quality. The rating agencies also view the Company's position as a strategically important subsidiary of Duke Energy to be a key factor in their credit ratings.

However, the rating agencies have identified a number of challenges the Company faces in maintaining its credit ratings, including:

- A decline in the credit supportiveness of the utility's regulatory framework: The rating agencies identify the current regulatory environment and suite of cost recovery mechanisms as credit supportive but acknowledge that changes to the regulatory environment could potentially pressure the credit profile of the Company.

- Environmental considerations: The rating agencies view Duke Energy Kentucky's reliance on coal-fired generation as a constraint on its risk profile and as exposing the Company to environmental risks. Because its reliance on coal-fired generation, Moody's states that Duke Energy Kentucky is poorly positioned for carbon transition.
- Capital expenditure growth: Capital expenditures in 2021 and 2022 fell below $200 million annually after several higher years which included investments focused on environmental compliance and the distribution system to improve reliability. Capital spending exceeded $200 million in 2023 and is expected to remain above $200 million annually over the next five years. The rating agencies also expressed concerns that additional capital investments could be required due to changing environmental regulations related to coal-fired generation.
- Small stand-alone size: The rating agencies view Duke Energy Kentucky's small customer base as making the Company vulnerable to localized adverse weather events that could affect operations.

Q. WHAT FACTORS COULD LEAD TO A CREDIT DOWNGRADE AT DUKE ENERGY KENTUCKY?

A. For rate-regulated utilities, the regulatory environment and how the utility adapts to that environment is the most important credit consideration made by the credit rating agencies. The ability to recover prudently incurred costs timely and earn a fair return is foundational to a utility's credit quality. Therefore, if there is a decline in the credit supportiveness of the regulatory environment, such as delays in recovery of prudently incurred costs through the absence of rider mechanisms or a reduced ROE and equity component, it could lead to weaker financing credit metrics and could result in a credit rating downgrade. Such an event could, in turn, negatively impact the Company's ability to access the financial markets on reasonable terms, and ultimately, increase the Company's costs to borrow funds. This, in turn, could result in increased costs to customers.

IV. CAPITAL STRUCTURE AND COST OF CAPITAL

Q. WHAT IS DUKE ENERGY KENTUCKY'S PROPOSED CAPITAL STRUCTURE?

A. As mentioned earlier in my testimony, Duke Energy Kentucky's proposed capital structure is comprised of 52.728 percent equity and 47.272 percent debt, after making adjustments for purchase accounting and other items. The Company believes this proposed capital structure is the appropriate capital structure for Duke Energy Kentucky, as it introduces an appropriate amount of risk due to leverage and minimizes the weighted average cost of capital to customers. Approval of the proposed capital structure will help Duke Energy Kentucky maintain its credit quality to meet its ongoing business objectives. This level is also consistent with the Company's target credit ratings.

Q. WHAT IS DUKE ENERGY KENTUCKY'S COST OF EQUITY?

A. Duke Energy Kentucky witness Joshua Nowak testifies regarding the Company's cost of equity. The Company supports Mr. Nowak's analysis and is requesting 10.85 percent as the Company's allowed ROE.

Q. WHAT ROLE DO EQUITY INVESTORS PLAY IN THE FINANCING OF DUKE ENERGY KENTUCKY, AND HOW WILL THE OUTCOME OF THIS CASE IMPACT THESE INVESTORS?

A. Equity investors provide the foundation of a company's capitalization by providing significant amounts of capital, for which an appropriate economic return is required. Duke Energy Kentucky compensates equity investors for the risk of their investment by targeting fair and adequate returns, a stable dividend policy, and earnings growth — these are necessary to preserve ongoing access to equity capital. Returns to equity investors are realized only after all operating expenses and fixed payment obligations (including debt principal and interest) of the Company have been paid. Because equity investors are the last in priority to a company's assets, their investment is at most risk should the company suffer any underperformance. For this reason, equity investors require a higher return on investment. Equity investors expect utilities like Duke Energy Kentucky to recover their prudently incurred costs and earn a fair and reasonable return for their investors. The Company's proposal in these proceedings supports this investor requirement.

Q. DO YOU BELIEVE THAT DUKE ENERGY KENTUCKY'S CAPITAL STRUCTURE HAS AN ADEQUATE EQUITY COMPONENT TO ENABLE DUKE ENERGY KENTUCKY TO ACHIEVE THE COMPANY'S FINANCIAL STRENGTH AND CREDIT QUALITY OBJECTIVES?

A. Yes. Duke Energy Kentucky's equity component, as supported in these proceedings, enables it to maintain current credit ratings and financial strength and flexibility. This level of equity enables the Company to operate without perpetually remaining at the very bottom of rating agencies' acceptable credit metrics, which in turn supports the Company's access to capital through different business cycles. In addition, the Company's current and future capital expenditures require the need for a strong equity component in the Company's capital structure in order to maintain access to capital funding at reasonable terms.

Q. IS IT APPROPRIATE TO CONSIDER DUKE ENERGY CORPORATION'S CAPITAL STRUCTURE WHEN DETERMINING THE CAPITAL STRUCTURE FOR DUKE ENERGY KENTUCKY?

A. No. Duke Energy Corporation is a non-regulated entity that sits outside of the jurisdiction of the Kentucky Public Service Commission. Comparing the capital structures of a non-regulated business to that of a regulated business is not appropriate. Duke Energy Kentucky funds its operations through retained earnings and the issuance of debt. The capital structure on its balance sheet is its true capital structure. The assets obtained by Duke Energy Kentucky to serve customers were financed in a manner consistent with the Company's capital structure as a regulated utility, not that of a parent-level holding company. Duke Energy Corporation's capital structure is significantly influenced by strategic transactions, for example the recent sale of its Commercial Renewables business, and acquisitions of other companies such as Progress Energy and Piedmont Natural Gas. Transactions such as these have impacted Duke Energy Corporation's diversity and scale, ultimately improving the credit profile of Duke Energy Corporation. They have also delivered benefits to Duke Energy Kentucky customers, such as reduced O&M costs due to operational efficiencies, yet those customers have not paid for the debt incurred at the holding company. Arbitrarily imposing a holding company capital structure upon Duke Energy Kentucky would significantly increase its leverage (and, therefore, financial risk), reduce its cash flows, and erode credit quality, all to the detriment of the customers through higher borrowing costs.

Q. PLEASE SUMMARIZE THE COMPANY'S AVERAGE COST OF SHORT-TERM AND LONG-TERM DEBT FOR THE FORECAST PERIOD AND THE KEY ASSUMPTIONS AND METHODOLOGY USED IN CALCULATING COST OF DEBT FOR SUCH PERIODS.

A. The table below presents the average cost of short-term and long-term debt for the forecast period:

	Forecast Period (Avg of Jun 2025 thru Jun 2026)
Short-Term Debt (Schedule J-2)	3.197 percent
Long-Term Debt (Schedule J-3)	4.929 percent

For Schedule J-2, which calculates cost of short-term debt, the Amount Outstanding for the Notes Payable to Associated Companies in the forecasted short-term debt schedule is the thirteen-month average of Duke Energy Kentucky's monthly money pool borrowing balance from current company projections. The interest rate on this debt was derived using Bloomberg's implied forward curve for one-month Term SOFR as of September 2024.

For Schedule J-3, which calculates the cost of long-term debt, the interest rate on $25 million of LT Commercial Paper for the forecast period was derived using Bloomberg's implied forward curve for one-month Term SOFR as of September 2024 plus a 25-basis point credit spread. Long-term, senior unsecured, debt issuances of $150 million and $175 million are forecasted for September 2025 and May 2026, respectively, based on company projections. The indicative interest rates on these future issuances were estimated using a weighted average of Bloomberg's forward curves for the 5-year, 10-year and 15-year US Treasury yield, respectively, as of September 2024 plus a 155 basis point credit spread for the 5 year debt offering, 175 basis point credit spread for the 10 year debt offering and a 185 basis point credit spread for the 15 year debt offering.

V. DUKE ENERGY KENTUCKY'S CAPITAL REQUIREMENTS

Q. WHAT ARE DUKE ENERGY KENTUCKY'S CAPITAL REQUIREMENTS DURING THE 2025-2027 TIME PERIOD?

A. Duke Energy Kentucky faces substantial capital needs over the next several years to satisfy debt maturities, upgrade aging infrastructure, and to further invest in energy efficiency. The Company's capital requirement for the regulated electric and gas businesses of Duke Energy Kentucky is projected to be approximately $1 billion during the period of 2025-2027. This amount consists of approximately $785 million in projected capital expenditures and approximately $215 million in debt maturities.

Q. HOW WILL DUKE ENERGY KENTUCKY'S CAPITAL REQUIREMENTS BE FUNDED?

A. Duke Energy Kentucky's capital requirements are expected to be funded from internal cash generation, the issuance of debt, and equity contributions from the Company's parent company, Duke Energy Ohio, Inc. It is important to remember that Duke Energy also has dividend obligations to its shareholders. Duke Energy's operating subsidiaries are expected to distribute approximately 65 percent of their earnings over the long run in support of these obligations.

VI. CAPITAL MARKET ALTERNATIVES AND APPLICABILITY TO DUKE ENERGY KENTUCKY

Q. PLEASE DISCUSS THE DIFFERENT DEBT CAPITAL MARKET ALTERNATIVES AND WHETHER EACH OF THESE ALTERNATIVES ARE APPLICABLE TO DUKE ENERGY KENTUCKY.

A. There are generally three primary fixed income debt capital market options: (1) Securities and Exchange Commission (SEC) public debt market, (2) Rule 144A private placement market, and (3) Section 4(a)(2) private placement market. I will briefly discuss each of these markets and their applicability to Duke Energy Kentucky herein.

The SEC public debt market is the deepest and most widely used debt market in the United States and debt securities issued in this market are available to both institutional investors and the general public. In the SEC public debt market bonds are traded in the secondary market and pricing levels on bonds are readily observable. To participate in the market issuers must be fully registered with the SEC and file SEC compliant financial statement on a quarterly and annual basis. Over $8 trillion was issued in the SEC public debt market in 2023. Investors in this market prefer transaction sizes of $300 million or more for secondary market liquidity. As Duke Energy Kentucky is not an SEC registered entity, the SEC public debt market is not a viable option.

The Rule 144A private placement market allows sales of debt securities to and secondary trading of debt securities among more sophisticated institutional investors which may not require the same type of information and protection as the general public. Under Rule 144A a minimum level of publicly accessible information is required from the issuer of the securities and issuers are only required to provide whatever information is requested by the purchaser before making the investment as compared to the extensive documentation required through filings with the SEC in the SEC public debt market. Over $1 trillion was issued in the Rule 144A market in 2023. Investors in this market also prefer transaction sizes of $300 million or more for secondary market liquidity. This market could be an option for Duke Energy Kentucky if it has a financing need of this size.

In the Section 4(a)(2) private placement market debt securities are offered to a limited pool of accredited investors and securities are fully exempt from any registration with the SEC. An established secondary market does not exist for this market and any transfers of securities are negotiated between buyers and sellers. Transactions in this market afford the issuer the opportunity to avoid certain costs associated with a public offering as well as allow for more flexibility regarding structure and terms. The smallest of the three fixed income markets, the Section 4(a)(2) market had issuances of approximately $100 billion in 2023. Transactions ranging from $25 million to $400 million are frequently executed in this market. Duke Energy Kentucky has historically utilized the Section 4(a)(2) market due to the size of its debt transactions.

Q. DO OTHER DUKE ENERGY KENTUCKY REGULATED AFFILIATES RELY UPON THE RULE 144A OR SECTION 4(A)(2) PRIVATE PLACEMENT MARKETS FOR FINANCING? PLEASE EXPLAIN.

A. Duke Energy Kentucky is the only regulated operating company within the Duke Energy organization that relies upon either of these private placement markets. Duke Energy Kentucky is also the smallest regulated operating company within the Duke Energy organization. The typical size of Duke Energy Kentucky's debt issuances are more appropriate for the Section 4(a)(2) private placement market which can accommodate financings of $100 million or less more efficiently that the SEC public debt or Rule 144A private placement markets. In addition, as Duke Energy Kentucky is not a SEC registered entity, it does not have ready access to the SEC public debt market as do other Duke Energy regulated operating companies.

Q. WHAT HAS BEEN THE BENEFIT OF SECTION 4(A)(2) PRIVATE PLACEMENT FINANCING FOR DUKE ENERGY KENTUCKY?

A. The Section 4(a)(2) private placement debt market is an alternative source of financing that provides Duke Energy Kentucky the opportunity to raise capital as it does not have to access the SEC public debt market (as it is not an SEC registered entity) and its historic debt issuances have been well below the transaction size preferred by investors in the Rule 144A private placement market. The Section 4(a)(2) private placement market has allowed Duke Energy Kentucky to have greater flexibility when raising capital but comes at the cost of the less competitive pricing compared to raising capital in the SEC public debt and Rule 144A private placement markets.

Q. HAS THE COMPANY EXPLORED OTHER WAYS TO LOWER ITS FINANCING COSTS TO THE BENEFIT OF RATE PAYERS IN LIGHT OF THE COMPANY'S EQUITY RATIO CONTINUING TO RISE?

A. Yes, the Company would prefer to access the Rule 144A private placement market to finance Duke Energy Kentucky's capital plan but is limited to Section 4(a)(2) private placement transactions due to investors' lack of interest in investing in a utility that has significant coal exposure and the relatively small size of its historic debt issuances.

Duke Energy Kentucky successfully completed a $225 million issuance of unsecured debentures through a negotiated Section 4(a)(2) private placement transaction with three investors in June 2024. The debentures were issued in three tranches targeted to the interest of each of the investors and were priced at a weighted average coupon of 6 percent. The Company chose to pursue a negotiated transaction instead of a fully marketed Section 4(a)(2) private placement transaction due to continued investor sensitivity over coal exposure and the expectation of aggressive, investor friendly changes to covenant provisions. Duke Energy Kentucky engaged in significant negotiations with the investor group over the course of several months to arrive at a competitively priced transaction with moderate changes to existing financing transaction documents. While this transaction was competitively priced, it lacked the ability to leverage pricing tension between investors that is commonly achieved in fully marketed transactions, including those in the Section 4(a)(2) private placement market.

Prior to the June 2024 debt issuance, Duke Energy's most recent debt issuances were $70 million (2020), $210 million (2019), $74 million (2018), $90 million (2017), and $95 million (2016), all well below the $300 million or more preferred transaction size in the Rule 144A private placement market. Each of these financings were used to fund Duke Energy Kentucky's capital spending and debt maturities. As Duke Energy Kentucky's capital plan increases over time there could be an opportunity to fund capital spending for multiple years in a single financing transaction that could be of a transaction size suitable of the Rule 144A private placement market. However, such a funding strategy would likely require Duke Energy Kentucky to utilize short-term debt, including borrowings under the Duke Energy Utility Money Pool Agreement and/or bank term loans, for a longer period of time.

VII. ACCOUNTS RECEIVABLES FINANCING PROGRAM

Q. PLEASE EXPLAIN THE COMPANY'S HISTORICAL ACCOUNTS RECEIVABLE FINANCING PROGRAM?

A. Until March 2024, Duke Energy Kentucky was a party to an agreement with its sister utilities in Ohio and Indiana, and the Cinergy Receivables Company (CRC), that effectively provided for debt financing collateralized by outstanding accounts receivables. The substance of the program was to use the accounts receivable of Duke

Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky as a security instrument in order to efficiently diversify the long-term debt raised by each these entities at reasonable interest rates. The CRC accounts receivable financing program included Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky for scale of borrowing and efficiency of administration. This financing arrangement isolated the accounts receivable from other assets of the utilities and structured a financing that relied on the strength of the accounts receivable rather than the creditworthiness of the utilities.

Duke Energy Kentucky traditionally raises debt capital from fixed-rate long-term private placement issuances. Lenders for these types of financings are typically insurance companies, pension funds, and money managers. The accounts receivable financing program provided Duke Energy Kentucky the opportunity to raise floating-rate debt funded by financial institutions. This financing method provided diversification of both the interest rates and lending institutions.

The legal documentation provided for the transfer of Duke Energy Kentucky's accounts receivable to CRC, a bankruptcy remote, special purpose entity owned by Cinergy Corp., a wholly-owned subsidiary of Duke Energy Corp. CRC used the receivables it obtained from Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky as collateral for borrowings under a credit facility with two financial institutions. Amounts borrowed under the credit facility were reflected on Duke Energy's Consolidated Balance Sheets as Long-Term Debt but were not reflected on the Consolidated Balance Sheets of Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky for GAAP due to technical consolidation accounting guidance. However, Duke Energy Kentucky did include its pro rata share of the outstanding debt of CRC in its embedded cost of debt for ratemaking purposes.

Q. IN RESPONSE TO THE COMMISSION'S ORDER IN CASE NO. 2022-00372, HAS THE COMPANY EVALUATED THE BENEFIT OF ITS ACCOUNTS RECEIVABLE FINANCING PROGRAM? PLEASE EXPLAIN.

A. Yes, in response to the Commission's order in Case No. 2022-00372 and a broader enterprise-wide analysis, Duke Energy evaluated all of its accounts receivable financing programs in late 2023 and early 2024. The evaluation considered a comparison of the borrowing costs of the accounts receivable financing programs relative to other alternative forms of financing and the amount of administrative support required to monitor, maintain, and oversee the programs. This evaluation determined that, under current market conditions, the accounts receivable financing programs were no longer producing the financial benefits originally intended as compared to other alternative forms of financing and that the administrative support required for these programs was extensive. As a result of this evaluation, Duke Energy decided to repay all outstanding borrowings under these programs and terminate the related credit agreements.

Q. WHAT IS THE STATUS OF THE CRC ACCOUNTS RECEIVABLE FINANCING PROGRAM?

A. The CRC accounts receivable financing program was terminated in March 2024 and all outstanding borrowings were repaid at that time.

Q. WILL THIS CHANGE RESULT IN INCREASED COSTS TO CUSTOMERS?

A. No, as stated previously, the cost of and administrative effort to support the CRC accounts receivable financing program exceed those of other alternative forms of financing. The requested revenue requirement in this case reflects the weighted average cost of debt for the forecast period, which does not include any costs related to the CRC accounts receivable financing program.

VIII. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE FR 12(2)(a).

A. FR 12(2)(a) provides the amount and kinds of stock authorized.

Q. PLEASE DESCRIBE FR 12(2)(b)

A. FR 12(2)(b) provides the amount and kinds of stock issued and outstanding as of September 30, 2024.

Q. PLEASE DESCRIBE FR 12(2)(c).

A. FR 12(2)(c) is a requirement to provide certain terms and conditions for any preferred stock. Since Duke Energy Kentucky has no preferred stock, there is no information to provide.

Q. PLEASE DESCRIBE FR 12(2)(d).

A. FR 12(2)(d) provides a description of certain terms and conditions for any mortgages. Since Duke Energy Kentucky has no mortgages, there is no information to provide.

Q. PLEASE DESCRIBE FR 12(2)(e).

A. FR 12(2)(e) provides certain terms and conditions for any bonds authorized and issued.

Q. PLEASE DESCRIBE FR 12(2)(f).

A. FR 12(2)(f) provides certain terms and conditions for any notes issued. Duke Energy Kentucky had no other notes outstanding beyond those summarized in 12(2)(e) and 12(2)(g).

Q. PLEASE DESCRIBE FR 12(2)(g).

A. FR 12(2)(g) provides certain terms and conditions for other indebtedness, including information on two outstanding series of Pollution Control Bonds and information on money pool borrowings.

Q. PLEASE DESCRIBE FR 12(2)(h).

A. FR 12(2)(h) provides certain information regarding dividend payments by Duke Energy Kentucky during the past five years.

Q. PLEASE DESCRIBE THE INFORMATION YOU PROVIDED IN SUPPORT OF FR 16(7)(h).

A. The information I sponsor on FR 16(7)(h) includes Duke Energy Kentucky's capital structure requirements. I provided this information to Mr. Carpenter for his preparation of the Company's financial forecast.

Q. PLEASE DESCRIBE FR 16(7)(j).

A. FR 16(7)(j) is a requirement to provide copies of the prospectuses of the most recent stock or bond offerings.

Q. PLEASE DESCRIBE FR 16(7)(l).

A. FR 16(7)(l) is a requirement to provide copies of the consolidated annual report to shareholders for the last two years.

Q. PLEASE DESCRIBE FR 16(7)(r).

A. FR 16(7)(r) is a requirement to provide copies of the past five quarterly reports to shareholders.

Q. PLEASE DESCRIBE SCHEDULES J-1.

A. These J schedules are embodied in FR 16(8)(j). Specifically, Schedule J-1, entitled "Cost of Capital Summary" sets forth the projected capital structure and capitalization ratios of Duke Energy Kentucky at February 28, 2025, and the average of the projected balances and rates for the thirteen-month period ending June 30, 2026. The weighted cost of the various capital components is computed by multiplying the respective capitalization ratio by the computed annualized cost rate. The overall weighted cost of capital is reflected in the rate of return requested for the thirteen-month period ending June 30, 2026.

Q. PLEASE DESCRIBE SCHEDULES J-2 AND J-3.

A. Schedule J-2, entitled "Embedded Cost of Short-Term Debt," and Schedule J-3, entitled "Embedded Cost of Long-Term Debt," set forth the calculations of the cost of short-term debt and long-term debt, respectively, of Duke Energy Kentucky. The information on page 1 of these schedules was computed at the date of the base period, February 28, 2025. On page 2, the balances and interest rates are based on the average of the projected balances and rates for the thirteen-month period ending June 30, 2026.

Q. WHY IS SCHEDULE J-4 NOT INCLUDED?

A. Schedule J-4 is designed to provide the embedded cost of preferred stock for Duke Energy Kentucky. Since Duke Energy Kentucky has no preferred stock, this schedule has not been filed.

Q. DO YOU SPONSOR ANY OF THE INFORMATION CONTAINED IN ANY OTHER SCHEDULES?

A. Yes. I sponsor the rating agencies' ratings, fixed charge coverage ratios and percentage of construction expenditures financed internally in Schedule K.

Q. PLEASE DESCRIBE THE INFORMATION YOU PROVIDED FOR SCHEDULE K IN RESPONSE TO FR 16(8)(K).

A. The information I sponsor includes Duke Energy Kentucky's senior unsecured credit ratings. I also provided information relating to consolidated capital structure and common stock related data to Ms. Danielle L. Weatherston for her use in preparing Schedule K.

IX. CONCLUSION

Q. WERE FR 12(2)(a), FR 12(2)(b), FR 12(2)(c), FR 12(2)(d), FR 12(2)(e), FR 12(2)(f), FR 12(2)(g), FR 12(2)(h), FR 16(7)(j), FR 16(7)(l), FR 16(7)(r), THE INFORMATION YOU PREPARED SUPPORTING FR 16(7)(h), SCHEDULES J-1 THROUGH J-4 IN RESPONSE TO FR 16(8)(j), AND SCHEDULE K PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. IS THE INFORMATION YOU SPONSORED IN THOSE SUPPLEMENTAL FILING REQUIREMENTS AND SCHEDULES ACCURATE TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

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. 2024-00354

DIRECT TESTIMONY OF

MATTHEW KALEMBA

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 2, 2024

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Matthew Kalemba, and my business address is 525 South Tryon Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS) as Vice President, Integrated Resource Planning. DEBS provides various administrative and other services to Duke Energy Kentucky and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science in Chemical Engineering from North Carolina State University in 2000 and a Master of Business Administration from Lake Forest Graduate School of Management in Chicago in 2012. From 2000 to 2014, I held various roles in the petroleum refining and petrochemical industry including process engineering, feedstock and supply chain management, and short-term, mid-term, and long-term strategy development. I joined Duke Energy in 2014 as an analyst in the Carolinas Integrated Resource Planning team and became Director of Distributed Energy Technologies Planning and Forecasting in March of 2020. In March of 2023, I became Managing Director IRP & Analytics for Duke Energy's Midwest regulated utilities. In March of 2024, I was promoted to my current position as Vice President Integrated Resource Planning.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS VICE PRESIDENT INTEGRATED RESOURCE PLANNING.

A. I oversee the development of the long-term resource plans for Duke Energy's electric utility operating companies, including that of Duke Energy Kentucky. The overriding objective of those plans is to provide customers with a generating system that is mindful of costs and risks, is increasingly diverse and environmentally sustainable.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes. Most recently, I provided testimony in Case No. 2023-00413.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THESE PROCEEDINGS?

A. My testimony is provided to support Duke Energy Kentucky's modeling as it relates to its generation supply portfolio forecasts, which include the estimated life of the Company's electric generating fleet and how the Company will replace those assets. In doing so, I summarize and explain the analysis that was performed in the Company's most recent Integrated Resource Plan (IRP) filed in Case No. 2024-00197 and support the Company's proposal in this case to fully recover depreciation expense, including terminal net salvage costs, for its two fossil generators, East Bend and Woodsdale. I also address portions of KRS 278.264's rebuttal presumption against retirement of fossil generation.

II. DISCUSSION

Q. ARE YOU FAMILIAR WITH THE INTEGRATED RESOURCE PLANNING PROCESS FOR DUKE ENERGY KENTUCKY?

A. Yes. Duke Energy Kentucky files its IRP approximately every three years. The Company recently filed its current IRP with the Commission in Case No. 2024-00197 in June 2024 (2024 IRP). This IRP provides a snapshot of Duke Energy Kentucky's resource planning at that point in time.

Q. WERE YOU INVOLVED WITH THE CREATION OF DUKE ENERGY KENTUCKY'S MOST RECENTLY FILED IRP?

A. Yes. I supervised the development of the Duke Energy Kentucky's IRP including developing the various portfolio scenarios that were analyzed in the IRP.

Q. PLEASE GENERALLY DESCRIBE THE IRP PLANNING PROCESS.

A. The IRP planning process assesses various supply-side, demand-side and emission compliance alternatives to develop a long-term, cost-effective portfolio to provide customers with reliable service at reasonable costs. The IRP planning process involves various assumptions such as future energy prices, future environmental compliance requirements and reliability constraints.

Duke Energy Kentucky's load forecasting group develops the load forecast by: (1) obtaining service area economic forecasts primarily from Moody's Analytics; (2) preparing an energy forecast by applying statistical analysis to certain variables such as number of customers, economic measures, energy prices, weather conditions, *etc.;* and (3) developing monthly peak demand forecasts by statistically analyzing weather data. The Company updates the load forecasts on a regular basis and the updated load forecasts are used for all modeling analysis. It is important to note that while Duke Energy Kentucky develops internal load forecasts for system planning purposes, the actual load forecast and the Duke Energy Kentucky PJM Interconnection, L.L.C (PJM) load obligation, which includes peak coincidence factors and system reserve requirements, is calculated by PJM and can differ slightly from the Company's internal forecast.

Q. PLEASE BRIEFLY DESCRIBE WHAT THE COMPANY'S 2024 IRP DETERMINED AS IT RELATES TO THE COMPANY'S GENERATING PORTFOLIO, AND PARTICULARLY, THE EAST BEND GENERATING STATION.

A. The Company's 2024 IRP shares some of the characteristics of its previous IRPs. It represents Duke Energy Kentucky's proposed roadmap to meet future energy and demand requirements without compromising reliability of service, energy affordability or the power demands of a growing region. The 2024 IRP reflects updated fuel and load forecasts, as well as updated new generation capital costs reflecting a dynamic macroeconomic and inflationary environment impacting supply chain and resource costs. Additionally, the 2024 IRP includes updated policies at both the state and federal level including:

- The Inflation Reduction Act (IRA) particularly expanded investment and production tax credits for non-CO_2 emitting generating resources;
- The Environmental Protection Agency (EPA) Clean Air Act (CAA) Section 111 April 2024 Updates (EPA CAA Section 111 Update) regulating existing coal and new natural gas generation facilities;

- Updates to Effluent Limitation Guidelines (ELG); 316 a & b (thermal discharge limits and fish impingement/entrainment at water intakes); and tightened Mercury & Air Toxics Standards (MATS); and
- Removal of a CO_2 tax on plant emissions as a likely future policy primarily due to the inclusion of the IRA and EPA CAA Section 111 Update provisions.

Importantly, the 2024 IRP reflects Duke Energy Kentucky's conversion of East Bend from 100% coal generation to coal generation with gas co-firing capabilities, or dual fuel operation (DFO) to be in service as of December 31, 2029. The 2024 IRP includes continued operation of the Woodsdale CT's and the addition of a combined cycle (CC) at East Bend beginning in January 1, 2039. The resource mix is supplemented by demand response and solar resources. A summary of the preferred portfolio of resources through 2040 as modeled in the IRP is provided as follows:

Resources (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
East Bend (coal)	600	600	600	600	600											
East Bend DFO						600	600	600	600	600	600	600	600	600		
East Bend CC (1x1)															664	664
Woodsdale CTs	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
Demand Response	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Solar	9	9	9	9	59	59	109	109	159	159	209	209	259	259	309	309

The primary difference between the 2021 plan and the 2024 plan is the conversion of East Bend from 100% coal generation to coal generation with natural gas co-firing capabilities, or DFO. This change is driven by environmental regulations, primarily the EPA CAA Section 111 Update that was not in place in 2021. EPA CAA 111 Update limits coal plants to four compliance pathways:

1. Retire by January 1, 2032 without restriction on operation until retirement;
2. Convert the unit to full natural gas operation by January 1, 2030;
3. Convert to at least 40% gas-cofiring by January 1, 2030; or
4. Add Carbon Capture and Sequestration (CCS) by January 1, 2032.

As part of its modeling, the Company determined that natural gas-cofiring was the preferred strategy because it adds needed fuel diversity and security to the Duke Energy Kentucky system, reduces customers' exposure to PJM market prices, provides for a measured energy transition while allowing time for technological advancements related to permanent replacement generation, and is in line with Kentucky's energy policies and priorities.

The 2024 IRP analyzes the portfolio beyond the life of East Bend's December 31, 2038 estimated retirement date as a result of the EPA CAA 111 Update, and includes a 1x1 CC as the optimal replacement resource for East Bend at the time of its retirement. Additionally, the IRP also includes renewable resource assumptions. While the 2024 IRP identifies replacement generation as a 1x1 CC, there is time between this filing and East Bend's compliance-driven retirement to allow other technologies such as nuclear small modular reactors (SMR) or CC paired with CCS (CC w/ CCS) to evolve such that these other technologies may be used as a replacement for East Bend.

Q. WHAT RELIABILITY CONSTRAINT ASSUMPTIONS ARE NECESSARY TO DEVELOP AN IRP?

A. A reliability constraint is included in the modeling process by the inclusion of a -6.1% reserve margin based on PJM's methodology for resource adequacy.

Q. PLEASE EXPLAIN HOW THE COMPANY MODELS THE DISPATCH OF ITS GENERATING STATIONS.

A. The Company utilizes a commercially available production cost model (Encompass) to model the dispatch of the Duke Energy Kentucky system as well as economic purchases and sales from/to the PJM market. All of the Company's generating units are represented in the model with their key characteristics, such as capacity, fuel type, heat rate, and emission rates. Other inputs include projected fuel costs for each unit, planned outages, forced outage rates, the market value for emission allowances, the market price for power, and the Company's load forecast for native load customers. For the period forecasted, the model provides projections of how generating units are expected to operate, including projections of fuel consumption and emissions.

Q. WHAT ARE THE COMPANY'S LOAD REQUIREMENTS?

A. The utility's load in 2024 is approximately 808 MW and, when Duke Energy Kentucky's required reserve margin of -6.13% is applied, the load requirement is approximately 758 MW. As the level and characteristics of the load change over time, the Company routinely assesses resource adequacy and adjusts its plans accordingly to ensure reliability in a cost-effective way for customers. Should new load come into the service territory, the Company will evaluate how that load fits within the overall utility's obligation in determining appropriate resource additions.

Q. DOES DUKE ENERGY KENTUCKY CURRENTLY HAVE SUFFICIENT CAPACITY TO MEET ITS KENTUCKY CUSTOMER LOAD OBLIGATIONS?

A. Yes. Duke Energy Kentucky currently has sufficient capacity to meet its load obligations; however, short-term capacity purchases may be necessary to maintain sufficient reserves and meet its capacity obligations in PJM. As was approved by the Commission in the Company's 2017 electric rate case, Case No. 2017-00321, Duke Energy Kentucky addresses short-term capacity shortfalls in its FRR plan through short-term capacity purchases and includes these purchases in its Profit Sharing Mechanism (PSM).

Duke Energy Kentucky continually evaluates its load obligations and its generation portfolio to ensure that there is adequate supply available. This evaluation factors in the unique circumstances and challenges the Company faces in its Northern Kentucky service territory. Duke Energy Kentucky is experiencing some load growth in its service territory and must plan to make sure the Company is able to meet such demand. While the East Bend and Woodsdale generating stations have been reliable and economic assets to satisfy base load and peaking obligations, the fact remains that Duke Energy Kentucky is heavily dependent upon these two stations to serve customers. As load demand grows, the Company's portfolio of resources should diversify to ensure there is a continued access to a stable, economic energy supply.

The most recent IRP includes additional renewable resources coming online through the IRP planning period (22 percent by 2035) with likely coal retirements due to market prices and likelihood of governmental action impacting the economics of fossil fuel. Particular projects may be smaller or larger depending on site size or in order to take advantage of any economies of scale. Additionally, the Company continues to consider and evaluate other potential supply-side resources and solutions that may be in the best interests of its Kentucky customers.

To address the diversification issue as well as account for the presence of new Federal action through the IRA as well as, the new EPA CAA Section 111 Update), the Company believes that a measured approach to transitioning the generation fleet makes sense for customers.

Q. DOES DUKE ENERGY KENTUCKY REGULARLY UPDATE ITS GENERATION FORECASTS AND PLANNING MODEL ASSUMPTIONS AS PART OF ITS NORMAL BUSINESS OPERATIONS?

A. Yes, the Company makes periodic updates to its planning assumption which includes fuel prices, regulation, cost of new generation, etc. Optimized portfolio model runs are made to assess the high-level value proposition of generation options.

Q. IS DUKE ENERGY KENTUCKY PROPOSING ANY CHANGES TO ITS RESOURCE PORTFOLIO IN THIS PROCEEDING?

A. No, the Company is forecasting a retirement of East Bend no later than December 31, 2038 as a result of the EPA CAA 111 Update as outlined in the 2024 IRP. As a result, the Company's Application acknowledges a need to update East Bend's depreciation rates to better align the depreciable lives with its estimated service life which currently reflects a December 31, 2038 retirement date. Additionally, under a no EPA CAA 111 Update scenario in the 2024 IRP, East Bend actually retires earlier, by December 31, 2035, due to economics and reliability concerns. In either event, the unit retires earlier than the current December 31, 2041, depreciable life date approved by the Commission in the Company's last electric rate case.

In addition, the Company is not forecasting any changes to the life of its Woodsdale Generating units.

Q. PLEASE EXPLAIN THE DRIVERS FOR THE ANTICIPATED EARLIER RETIREMENT OF EAST BEND BY DECEMBER 31, 2038 UNDER THE EPA CAA 111 UPDATE.

A. As I previously stated, the EPA CAA Section 111 Update regulating existing coal and new natural gas generation facilities provides coal plants with four different compliance pathways:

1. Retire by 1/1/2032 without restriction on operation until retirement;
2. Convert to full natural gas operation by 1/1/2030;
3. Convert to at least 40% gas-cofiring by 1/1/2030 with a required retirement date of 12/31/2038; and

4. Add Carbon Capture and Sequestration (CCS) by 1/1/2032.

The Company determined that natural gas co-firing adds needed fuel diversity and security to the Duke Energy Kentucky system, reduces customers' exposure to PJM market prices, provides for a measured energy transition while allowing time for technological advancements related to permanent replacement generation, and is in line with Kentucky's energy policies and priorities. Of the viable pathways, the gas co-firing pathway was the lowest cost portfolio based on present value of revenue requirements (PVRR) as shown in Table 1 below.

Table 1: PVRRs for Optimized and Alternate IRP Portfolios with USEPA 111d ($MM)

	With USEPA 111d
Optimized Portfolios	
East Bend DFO Conversion by 2030	$2,592
East Bend Natural Gas Conversion by 2030	$2,629
East Bend Retirement by 2032	$2,618
Alternate Portfolios	
East Bend DFO Conversion with CC Replacement by 2039	$2,667
East Bend DFO Conversion with SMR Replacement by 2039	$2,677
East Bend DFO Conversion with CC with CCS Replacement by 2036	$2,499
East Bend DFO Conversion with CC Replacement by 2039 and Accelerated Renewables	$2,669
East Bend Retirement by 2032 with CC Replacement	$2,753

Note: DFO = dual fuel optionality, indicating coal/gas co-firing; SMR = small modular reactor; CCS = carbon capture and sequestration

"East Bend DFO Conversion with CC Replacement by 2039 and Accelerated Renewables" (PVRR shaded green in Table 1) is the preferred portfolio for the 2024 IRP.

As the PVRR results in Table 1 illustrate, the optimized DFO portfolio has a lower PVRR than the optimized Natural Gas Conversion portfolio and has a lower PVRR than the optimized Retirement portfolio. The EnCompass capacity expansion model used in the IRP selected a CC with CCS as the replacement for East Bend 2 in the optimized DFO and Retirement portfolios, but the Company concluded that CCS technology has not achieved a level of maturity sufficient to form the basis of the preferred portfolio. In the absence of a CC with CCS as a replacement resource option, the natural gas conversion portfolio does have a slightly lower PVRR. However, as explained in Section 6 of the IRP, co-firing (DFO) provides fuel flexibility, which is particularly valuable in this period of regulatory and fuel market uncertainty.

Q. PLEASE EXPLAIN THE DRIVERS FOR THE ANTICIPATED EARLIER RETIREMENT OF EAST BEND BY DECEMBER 31, 2035 UNDER A NO EPA CAA 111 UPDATE SCENARIO.

A. The primary drivers for the anticipated earlier retirement of East Bend by December 31, 2035, under a No EPA CAA 111 Update scenario include cost, reliability, and flexibility to adapt to a changing PJM marketplace. Without the fuel diversity of the DFO project, East Bend would be reliant on a potentially fading coal market in the latter half of the 2030s and would continue operating with high costs and risks associated with maintaining reliable operations beyond 2035 on 100% coal. Additionally, the flexibility of a CC aids system operators in ensuring a reliable system by providing ramping and dispatchability that will become more valuable as intermittent resources increase on the PJM system.

From a cost perspective, as shown in Figure 6.4 and 6.12 of the 2024 DEK IRP (and reproduced below as Figure 1 and Figure 2), the PVRR of retiring East Bend by December 31, 2035 is the lowest cost option among the portfolios evaluated through the majority of the plan, and the retirement by 2042 case only becomes economic in the final two years of the plan (i.e. dark blue line in chart falls below the preferred case, or dark yellow line in 2039) when Duke Energy Kentucky is significantly more reliant on the market with East Bend on coal. This signals that the Company's customers are at greater risk of higher market costs over the long term while East Bend operates on coal.

Figure 1 – Reproduced Figure 6.4 – PVRR ($000) – Alternate Without EPA CAA Section 111 Update

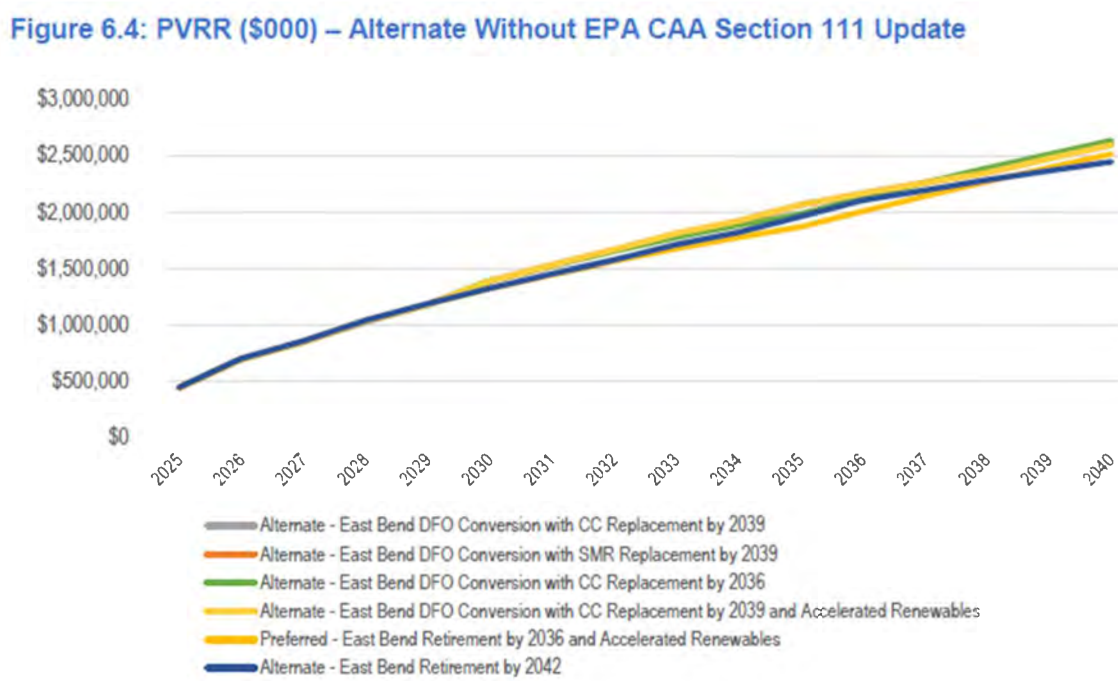
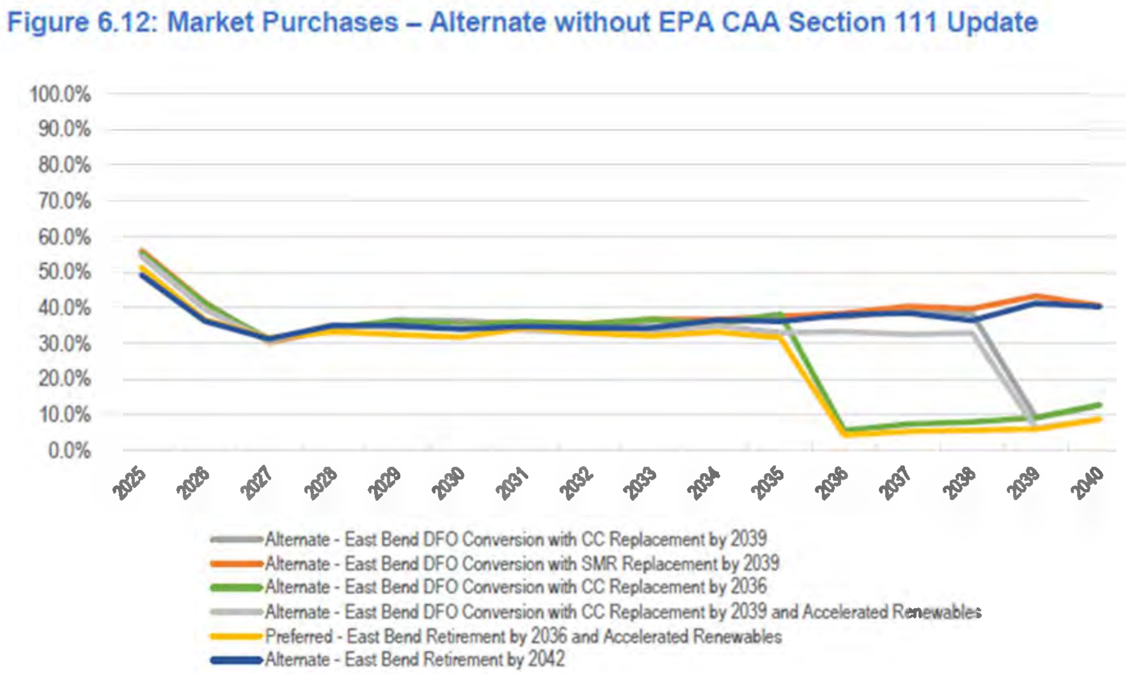


Figure 2 – Reproduced Figure 6.12 – Market Purchases – Alternate Without EPA CAA Section 111 Update



Q. IS DUKE ENERGY KENTUCKY SEEKING COMMISSION AUTHORIZATION TO RETIRE EAST BEND IN THIS PROCEEDING?

A. No. However, it must be acknowledged that East Bend will retire eventually, and modeling supports the retirement, in compliance with the EPA CAA 111 Update, no later than December 31, 2038. As part of this case, the Company is seeking to align the depreciation rates, including to reinstate recovery of terminal net salvage expense for East Bend, with that known retirement date.

As I understand, due to a change in Kentucky energy policy that occurred in 2023, there is a rebuttable presumption against the retirement of any Kentucky fossil fueled generation. And as part of the Company's 2022 electric rate case, Case No. 2022-00372, the Commission denied the Company's request to align East Bend's depreciation rates with its modeled operational life because the Company did not meet the rebuttable presumption from legislation, KRS 278.264, that was enacted months after the Company filed its application. Accordingly, here the Company is attempting to fix this deficiency, address the rebuttable presumption to properly recover depreciation expense, and eliminate the intergenerational subsidy created through the removal of terminal net salvage from rate recovery.

Q. PLEASE EXPLAIN THIS REBUTTABLE PRESUMPTION.

A. Although I am not an attorney, I have reviewed the statute, KRS 278.264, which created that presumption. The statute states as follows, in relevant part:

> (2) There shall be a rebuttable presumption against the retirement of a fossil fuel-fired electric generating unit. The commission shall not approve the retirement of an electric generating unit, authorize a surcharge for the decommissioning of the unit, or take any other action which authorizes or allows for the recovery of costs for the retirement of an electric generating unit, including any stranded asset recovery, unless the presumption created by this section is rebutted by evidence sufficient for the commission to find that:
>
> (a) The utility will replace the retired electric generating unit with new electric generating capacity that:
>
> 1. Is dispatchable by either the utility or the regional transmission organization or independent system operator responsible for balancing load within the utility's service area;
> 2. Maintains or improves the reliability and resilience of the electric transmission grid;
> 3. Maintains the minimum reserve capacity requirement established by the utility's reliability coordinator; and
> 4. Has the same or higher capacity value and net capability, unless the utility can demonstrate that such capacity value and net capability is not necessary to provide reliable service;
>
> (b) The retirement will not harm the utility's ratepayers by causing the utility to incur any net incremental costs to be recovered from ratepayers that could be avoided by continuing to operate the electric generating unit proposed for retirement in compliance with applicable law;

(c) The decision to retire the fossil fuel-fired electric generating unit is not the result of any financial incentives or benefits offered by any federal agency; and

(d) The utility shall not commence retirement or decommissioning of the electric generating unit until the replacement generating capacity meeting the requirements of paragraph (a) of this subsection is fully constructed, permitted, and in operation, unless the utility can demonstrate that it is necessary under the circumstances to commence retirement or decommissioning of the existing unit earlier.

(3) The utility shall at a minimum provide the commission with evidence of all known direct and indirect costs of retiring the electric generating unit and demonstrate that cost savings will result to customers as a result of the retirement of the electric generating unit.

Q. PLEASE EXPLAIN HOW DUKE ENERGY KENTUCKY WILL MEET ITS LOAD REQUIREMENTS ONCE EAST BEND IS RETIRED ACCORDING TO THE 2024 IRP.

A. Duke Energy Kentucky will meet its load requirements by replacing the 600 MW East Bend coal facility with a 664 MW 1x1 Natural Gas CC. This decision is supported by detailed analysis contained in the 2024 IRP.

Q. PLEASE EXPLAIN THE OPERATING CHARACTERISTICS OF THE 1X1 CC UNIT THAT WILL REPLACE EAST BEND UPON ITS RETIREMENT.

A. The 1x1 CC will operate up to 40% annual capacity factor under the EPA CAA Section 111 Update. The EPA CAA Section 111 Update does not preclude the 1x1 CC from operating as a base load generator for extended periods of time throughout the year when needed, but, on average, for the year, the unit is limited to 40% CF. Additionally, the 1x1 CC will provide greater ramping capabilities that may become more valuable to the PJM system as the amount of intermittent generation increases in the market. As Mr. Swez describes in his testimony, this replacement generation will be as or greater than East Bend in terms of both reliability and dispatchability in the PJM market.

Q. WILL THE FORECASTED 664 MW 1X1 CC THAT WILL REPLACE EAST BEND UPON ITS RETIRMENT MAINTAIN THE MINIMUM RESERVE CAPACITY REQUIREMENT ESTABLISHED BY PJM? PLEASE EXPLAIN.

A. Yes. As shown in Table 4.2 of the 2024 IRP, the current Effective Load Carrying Capability Class Ratings for a Gas CC in PJM is 79% while a coal facility rating is 84%. This means that East Bend contributes approximately 504 MW (84%) of its installed capacity towards meeting reserve capacity requirements while a new CC contributes approximately 525 MW (79%) thereby providing enough capacity to maintain at least the minimum reserve capacity required by PJM.

Q. WILL THE FORECASTED 664 MW 1X1 CC THAT WILL REPLACE EAST BEND UPON ITS RETIRMENT PROVIDE THE SAME OR HIGHER CAPACITY VALUE AND NET CAPABILITY? PLEASE EXPLAIN.

A. Yes. As discussed above, the 1x1 CC that will replace East Bend provides higher capacity value and net capability than the East Bend facility that the CC is replacing.

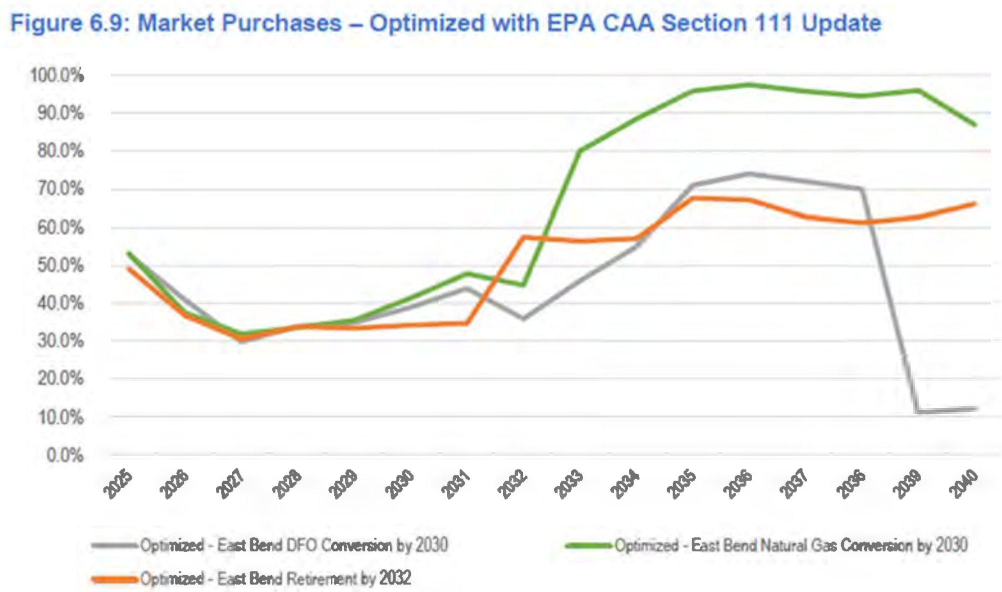
Q. IS THE ANTICIPATED RETIREMENT A RESULT OF ANY FINANCIAL INCENTIVES OR BENEFITS OFFERED BY ANY FEDERAL AGENCY? PLEASE EXPLAIN.

A. No. In fact, the opposite is true. The anticipated retirement of East Bend is due to economics, and environmental regulations that prohibit the Company from continuing to operate the unit past a certain date. The economics of the unit as determined by the Company's 2024 IRP modeling, selected a preferred case that provided the greatest value to customers and kept the unit operating as long as legally possible under the law. There is zero incentive or financial benefit being provided to the Company to retire the unit in 2038, as modeled. Moreover, under the no EPA CAA 111 Update scenario, the economic and reliability considerations of the unit actually support an even earlier retirement as being beneficial to customers.

Q. PLEASE EXPLAIN HOW DUKE ENERGY KENTUCKY'S ANALYSIS SHOWS THAT THE ANTICIPATED RETIREMENT OF EAST BEND WILL CAUSE NO HARM TO UTILITY RATEPAYERS AND WILL RESULT IN COST SAVINGS FOR CUSTOMERS WHEN ACCOUNTING FOR ALL KNOWN DIRECT AND INDIRECT COSTS OF RETIREMENT?

A. The IRP provides an analysis of the costs and risks of the potential operating outcomes of East Bend. The analysis includes a calculation of PVRR, which accounts for all known direct and indirect costs, as well a view of the Duke Energy Kentucky's reliance on the PJM marketplace, which identifies market exposure risk, under the varying outcomes. As mentioned previously, the preferred portfolio, developed under the EPA CAA Section 111 update, converts East Bend to DFO by 2030 and retires the asset by 2039. The alternatives to this plan are to convert East Bend to 100% natural gas by 2030 and retire in the 2040s or retire the asset by 2032. While potentially a lower cost portfolio, converting East Bend to fire 100% natural gas puts significant risk on customers because the unit would be limited to burning only gas on a unit that is highly inefficient compared to other gas fired units in PJM. This would result in customers relying on the PJM market for nearly 100% of their energy as shown in the green line in Figure 3 below.

Figure 3 – Reproduced Figure 6.9 – Market Purchases – Optimized with EPA CAA Section 111 Update



The other alternative, retiring East Bend by 2032, results in a higher cost portfolio because replacement generation is accelerated from the late 2030s to the early 2030s. The combination of PVRR and risk considerations makes the retirement of East Bend by 2039 the only alternative that reduces harm to customers while minimizing costs.

Q. WHAT IS THE ANTICIPATED RETIREMENT DATE FOR WOODSDALE AND WHAT IS THE COMPANY PROPOSING WITH RESPECT TO WOODSDALE'S DEPRECIABLE LIFE IN THIS CASE?

A. Currently, based upon the performance of the Woodsdale units, their regular maintenance, and the fact that these units are used for peaking service, the Company is maintaining the existing estimated service life of these assets to reflect a retirement date of December 31, 2040. As part of its decision in Case No. 2022-00372, the Commission found that deprecation rates should reflect retirement dates of December 31, 2040, for Woodsdale. The Company is seeking to maintain this depreciable life to remain aligned with the anticipated retirement date of these assets. The Company is seeking to include terminal net salvage value in its depreciation expense for Woodsdale based on the December 31, 2040, retirement date. Company witnesses Spanos and Lawler discuss this further in their testimonies.

Q. HOW WILL DUKE ENERGY KENTUCKY REPLACE WOODSDALE ONCE RETIRED?

A. The 2024 IRP 15-year time frame did not include evaluation of Woodsdale's retirement in December of 2040; however, it cannot be assumed the Woodsdale CTs will never retire. The Company anticipates replacing Woodsdale with similarly dispatchable firm capacity that will be compliant with all Kentucky legislation or statutes in place at that time. Future IRPs will more precisely identify which replacement technologies provide the best solution for customers. Prior to seeking Commission approval to retire Woodsdale and replace it with a new facility, Duke Energy Kentucky will thoroughly evaluate the market and available technologies, and bring those solutions to the Commission well in advance of the proposed retirement to ensure there is a seamless transition for customers. Nonetheless, the issue of terminal net salvage and avoiding intergenerational cost subsidies should be addressed, as further explained by Ms. Lawler and Mr. Spanos.

Q. WILL THE COMPANY REPLACE WOODSDALE WITH AN ASSET THAT IS DISPATCHABLE BY EITHER THE UTILITY OR THE REGIONAL TRANSMISSION ORGANIZATION OR INDEPENDENT SYSTEM OPERATOR RESPONSIBLE FOR BALANCING LOAD WITHIN THE UTILITY'S SERVICE AREA? PLEASE EXPLAIN.

A. Yes, the Company intends that the replacement generation for Woodsdale can be committed and/or operated to respond to instructions sent by either PJM or the Company as a result of either a change in demand or market prices.

Q. WILL THE COMPANY REPLACE WOODSDALE WITH AN ASSET THAT MAINTAINS OR IMPROVES THE RELIABILITY AND RESILIENCE OF THE ELECTRIC TRANSMISSION GRID? PLEASE EXPLAIN.

A. Yes. The replacement technology for Woodsdale is expected to, at a minimum, maintain the reliability and resilience of the electric transmission grid as required by KRS 278.264. From a practical perspective, replacement of an over 45-year-old asset with a new resource will, by itself, maintain or improve the reliability and resilience of the electric transmission grid.

Q. WILL THE COMPANY REPLACE WOODSDALE WITH AN ASSET THAT MAINTAINS THE MINIMUM RESERVE CAPACITY REQUIREMENT ESTABLISHED BY THE UTILITY'S RELIABILITY COORDINATOR? PLEASE EXPLAIN.

A. Yes. The Company plans that the replacement to Woodsdale will maintain the minimum reserve capacity requirement established by PJM.

Q. WILL THE COMPANY REPLACE WOODSDALE WITH AN ASSET THAT HAS THE SAME OR HIGHER CAPACITY VALUE AND NET CAPABILITY, UNLESS THE UTILITY CAN DEMONSTRATE THAT SUCH CAPACITY VALUE AND NET CAPABILITY IS NOT NECESSARY TO PROVIDE RELIABLE SERVICE.

A. Yes, the replacement generation to Woodsdale will provide the same or higher capacity value and net capability as necessary to provide reliable service.

Q. CAN YOU CONFIRM THAT THE COMPANY'S DECISION TO EVENTUALLY RETIRE WOODSDALE IS NOT THE RESULT OF ANY FINANCIAL INCENTIVES OR BENEFITS OFFERED BY ANY FEDERAL AGENCY?

A. Yes, the decision is not based on any incentive or benefit offered by any federal agency. The Company's decision to retire Woodsdale in 2040 is driven by the need to maintain a reliable and resilient electrical system to the benefit of Duke Energy Kentucky's customers. There are no financial incentives offered by any federal agency that is driving the Company's decision.

Q. WILL DUKE ENERGY KENTUCKY COMMENCE RETIREMENT OR DECOMMISSIONING OF WOODSDALE BEFORE THE REPLACEMENT GENERATING CAPACITY MEETING THE REQUIREMENTS OF KRS 278.264 IS FULLY CONSTRUCTED, PERMITTED, AND IN OPERATION?

A. No. Again, the Company is not seeking authorization to retire and replace Woodsdale in this case. The Company is simply asking to adjust the depreciation expense for Woodsdale to include terminal net salvage value based on a December 31, 2040 retirement date.

Q. PLEASE EXPLAIN THE FACTORS THAT ARE IMPACTING WOODSDALE'S REMAINING SERVICE LIFE.

A. The primary factors impacting Woodsdale's remaining service life are the cost and feasibility to maintain the reliability of the asset as the Woodsdale CTs reach 45 to 50 years of age. As Witness Luke explains, as a plant ages, there becomes a point in time when the equipment and systems become nearly impossible to service and maintain. Parts and materials become obsolete, and original equipment manufacturers ("OEMs") and other suppliers cease providing service and support. Even if these suppliers and OEMs are still available to provide their services, the cost to maintain reliable service will increase as the assets require more frequent maintenance as the asset continues to age. While the IRP does not capture the risk of parts and materials becoming obsolete, the IRP does include on-going costs to maintain the reliability of Woodsdale over time. Those costs, along with the risks Witness Luke highlights, are considered when assessing Woodsdale's remaining service life.

Because Woodsdale will eventually need to be retired and replaced to meet customer demand, customers will eventually pay these costs. The Company's goals are to minimize these costs for customers to the greatest extent by spreading them out over a reasonable time, while ensuring that investments made are fully recovered for the Company and its investors. The best way to do that is for the Commission to allow this cost recovery to occur over time and not saddle future customers with the costs of retirement of an asset that is being used to benefit customers today. To do otherwise will harm rate payers and will only serve to increase costs to customers.

III. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

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. 2024-00354

DIRECT TESTIMONY OF

IBRAR A. KHERA

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 2, 2024

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ibrar A. Khera. My business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS) as a Lead Load Forecasting Analyst in the Load Forecasting group. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold a Bachelor of Science degree in Mathematics, Bachelor of Arts in Economics, and Master of Arts in Economics from University of Nevada Las Vegas.

I have been employed by Duke Energy Business Services LLC since October 2022. I have eight years of forecasting experience, five years of which were in the Utilities sector. I was a load forecaster at NV Energy where I forecasted sales volume, customer counts and peak demand for use in development of financial budgets, general rate cases, Energy Supply Plans ("ESP"), ESP updates, and the Integrated Resource Plans ("IRP") for the Reno service areas. I was also a Senior Utility Analyst at Public Utilities Commission of Nevada, where I was responsible for reviewing various general rate case and resource plan filings and providing recommendations to the Commission on issues related to load forecasts and billing determinants.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS A LEAD LOAD FORECASTING ANALYST.

A. My responsibility is to develop long-term electric forecasts of customers, energy sales, and peak demand for Duke Energy's Midwest service areas, including Duke Energy Kentucky. These forecasts and analyses are provided to departments throughout Duke Energy and are used for budgeting, generation planning, and for regulatory filings, such as long-term forecast reports, IRPs, and rate cases.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony presents and explains Duke Energy Kentucky's long-term energy and demand forecast prepared and used in the Company's electric rate case filing. This includes a discussion of the level of normal weather utilized in the preparation of the forecast. In addition, I describe how Duke Energy Kentucky's current portfolio of regulated demand side management (DSM), energy efficiency (EE), and load management programs, which help Duke Energy Kentucky meet its energy and peak demand requirements, are factored into the load forecast. Because of some differences in terminology, I will refer to these programs collectively as Utility Energy Efficiency (UEE) Programs throughout my testimony. I sponsor Filing Requirement (FR) 16(7)(h)(5). I also discuss certain information that I supplied to Duke Energy Kentucky witnesses Mr. Tripp Carpenter and Mr. Bruce Sailers for their use in preparing additional testimony.

II. LOAD FORECAST

Q. DID YOU PREPARE THE COMPANY'S LOAD FORECAST FOR THIS RATE CASE?

A. Yes, I did.

Q. HOW WAS DUKE ENERGY KENTUCKY'S LOAD FORECAST DEVELOPED?

A. The load forecast is developed in three steps: first, a service area economic forecast is obtained; next, an energy forecast is prepared; and finally, using the energy forecast, summer and winter peak demand forecasts are developed.

The forecast is the same as that presented in Duke Energy Kentucky's past IRPs filed with the Kentucky Public Service Commission (Commission).

Q. PLEASE DESCRIBE HOW THE SERVICE AREA ECONOMIC FORECAST IS OBTAINED.

A. The economic forecast for northern Kentucky and the greater Cincinnati region is obtained from Moody Analytics' portal *Economy.com* (Moody's), a nationally recognized economic forecasting firm. Based upon its forecast of the national economy, Moody's prepares a forecast of key economic concepts specific to the greater Cincinnati area, including the portion of northern Kentucky served by Duke Energy Kentucky. This forecast provides detailed projections of employment, income, wages, industrial production, inflation, prices, and population. This information serves as input into the energy forecast models.

The Duke Energy Kentucky service area is located in northern Kentucky adjacent to the city of Cincinnati, which is contained within the service area of Duke Energy Ohio, another subsidiary of Duke Energy. The economy of northern Kentucky is contained within the Cincinnati Primary Metropolitan Statistical Area (PMSA) and is an integral part of the regional economy.

Q. DO YOU ALSO PRODUCE THE COMPANY'S FORECAST FOR THE NUMBER OF CUSTOMERS?

A. Yes, the forecasts for the number of customers are produced using the same modeling techniques and data sources as our forecasts for sales volumes.

Q. HOW IS THE ENERGY FORECAST DEVELOPED?

A. The energy forecast projects the load required to serve Duke Energy Kentucky's retail customer classes - residential, commercial, industrial, government or other public authority (OPA), and street lighting. The projected energy requirements for Duke Energy Kentucky's retail customers are determined through econometric analysis. Econometric models are a means of representing energy drivers such as weather, appliance saturation and efficiency, economic behavior through the use of regression analysis, which attributes historically measured changes in sales to variation in a series of predictive variables.

Q. WHAT ARE THE PRIMARY FACTORS AFFECTING ENERGY USAGE?

A. Some of the major factors are the number of residential customers, weather, and economic activity measures such as employment, industrial production, income, and price. For the residential sector, the key factors are the population of the area, real median per capita income, real energy prices, weather, appliance saturations, and appliance efficiencies. For the commercial sector, the key factors include the number of commercial customers, weather, employment and income, and real energy prices. The appliance data on saturation and efficiencies are incorporated into the residential usage and commercial models through the use of an additive term commonly referred to as a “statistically adjusted end-use” term (SAE term). The SAE term allows for this data to interact with the key factors named above. In the industrial sector, the key factors affecting energy use include manufacturing GDP, manufacturing employment, and the weather. The governmental sector model includes the specific portion of economic output that Moody’s classifies as government gross domestic product (“Government GDP”) as well as weather. Finally, for the street lighting sector, the key factor affecting energy use is the time of the year.

Generally, energy use increases with higher industrial and commercial activity along with the increased saturation of residential appliances, including space heating and cooling equipment. As energy prices increase, energy usage tends to decrease due to customers’ conservation activities.

Q. ARE THESE FACTORS RECOGNIZED IN THE EQUATIONS USED TO PROJECT THE ENERGY REQUIREMENTS OF DUKE ENERGY KENTUCKY'S RETAIL CUSTOMERS?

A. Yes, they are. By exposing the forecasting models to these variables, we can project future energy consumption conditional on forecasts of these economic and weather conditions.

Q. HOW IS THE FORECAST OF ENERGY REQUIREMENTS FOR DUKE ENERGY KENTUCKY'S RETAIL CUSTOMERS PREPARED?

A. While many economic and weather variables are relevant to the entire greater Cincinnati area, the Duke Energy Kentucky sales forecast is developed by maintaining specific forecasting models for sales only to Duke Energy Kentucky customers in the residential, commercial, industrial, government or OPA, and street lighting sectors. Forecasts are also prepared for three minor categories: interdepartmental use, Company use, and line losses associated with transmission and distribution. Rather than there being separate customer class models, the peak forecast model—discussed in greater detail down below—is estimated on a total retail basis.

Q. ARE THERE ANY ADJUSTMENTS MADE TO THE ALLOCATED FORECASTS DERIVED FROM THE ECONOMETRIC MODELS?

A. The output of the model estimation is adjusted for the impacts of projected growth in behind-the-meter solar generation, electric vehicle usage, and the impacts of new energy efficiency programs. The Company may adjust the forecast for anticipated increases in load due to a major new customer or a significant expansion at a current customer's site. For the load forecast for this case, an adjustment was made to add load for one large commercial customer that has committed to doing business within the region and is located in the Company's service territory.

Q. PLEASE EXPLAIN HOW THE PEAK FORECASTS ARE DEVELOPED.

A. The Company projects both a winter and a summer peak for the total region using econometric equations that forecast peak demand as a function of economic growth, as measured by energy sales, end-use data, and several key weather factors. The Duke Energy Kentucky peak load forecast is estimated separately from any other system peak. The model is exposed to monthly peak data, with normalized weather conditions for the day of peak based on thirty-year data. Attachment IAK-1 shows the monthly peak weather normal degree days used to compute peaks for Duke Energy Kentucky.

Q. DOES DUKE ENERGY KENTUCKY'S ENERGY AND PEAK LOAD FORECAST ALREADY INCLUDE THE IMPACT OF HISTORICAL UEE PROGRAMS?

A. Yes, the impact of the historical UEE programs that have been implemented in the Duke Energy Kentucky service area are already reflected in these forecasts. The data used to develop the load forecast incorporate the historical impact of those existing programs prior to model estimation. The model output is then readjusted downwards for those, as well as future UEE program projections.

Q. DOES DUKE ENERGY KENTUCKY'S LOAD FORECAST USED IN THIS CASE INCLUDE CONSIDERATION OF THE IMPACT FROM THE INSTALLATION OF COST-EFFECTIVE ENERGY UEE PROGRAMS?

A. Yes. It is my understanding that, according to the Commission's Order, in Administrative Case 2008-00408, utilities must explain consideration of cost-effective energy efficiency resources and the impacts of such resources on the utility test year. For Duke Energy Kentucky, incremental peak load reductions due to current and future UEE programs are used to adjust the historical data as part of the process of calculating the load forecast. The projected incremental impact of existing programs for the years 2024 through 2025 is an additional reduction of almost 26,000 MWh total, and 2.4 MW at time of peak. The load forecast for this case reflects those projected energy efficiency impacts.

Q. IS DUKE ENERGY KENTUCKY'S LOAD FORECASTING METHODOLOGY SIMILAR TO THAT EMPLOYED AT THE TIME OF THE COMPANY'S LAST BASE ELECTRIC RATE CASE?

A. Yes, the econometric forecasting methodology used to create the load forecast in this case is generally the same as that used by the Company in prior cases.

Q. HAS DUKE ENERGY KENTUCKY'S LOAD FORECAST USED IN THIS FILING BEEN PRESENTED BEFORE THE COMMISSION?

A. Yes, the Company submitted the current load forecast in the 2024 Integrated Resource Plan of Duke Energy Kentucky, which was filed in Case No. 2024-00197.

Q. ARE YOU FAMILIAR WITH OTHER ELECTRIC UTILITIES' LONG-TERM LOAD FORECASTS?

A. Yes, I am.

Q. ARE THE FACTORS THAT ARE USED BY DUKE ENERGY KENTUCKY IN FORMULATING ITS LOAD FORECASTS SIMILAR TO THE FACTORS USED BY OTHER UTILITIES IN THEIR LOAD FORECASTS?

A. Yes. While other utilities might use a variety of load forecasting approaches, such as econometric, end-use, trend analysis, or time series analysis, nearly all the utilities I am familiar with use the same or similar factors considered by Duke Energy Kentucky that I listed above. In addition, price forecasts for alternate fuels including natural gas and fuel oil are considered. I am aware of survey data indicating that many large utilities use an approach consistent with this methodology.

Q. HOW DOES MANAGEMENT JUDGMENT FIT INTO THE LOAD FORECASTS?

A. Under any approach to load forecasting, judgment is an essential element. Each utility must use the approach that, in its judgment, best suits its particular situation, taking into account the various factors. Examples of this would be advice from the sales team about conditions on the ground that are related to regional growth, or advice from the managers of energy efficiency and demand side management programs that provide incentives for customers to reduce energy usage about customer trends.

Q. PLEASE DESCRIBE ATTACHMENT IAK-2.

A. Attachment IAK-2 is a summary of Duke Energy Kentucky's energy forecast. The projected annualized rate of growth in total retail sales—measured on a calendar basis—for the five-year period 2024 to 2029 is 0.0 percent and for the ten-year period 2024 to 2034 is 0.3 percent per year.

That growth rate—while mathematically correct for the period in question—is not adequate for summarizing several dynamics that affect demand for energy during the near term. As I noted, there are also adjustments for one large commercial customer that has committed to doing business within the region and is located in the Company's service territory.

Q. PLEASE DESCRIBE ATTACHMENT IAK-3

Attachment IAK-3 is a summary of Duke Energy Kentucky's peak load forecast. The projected annualized rate of growth in energy demand at time of peak is 0.1 percent for the five-year period, and 0.4 percent for the ten-year period.

III. <u>DEGREE DAY DATA USED IN THE FORECAST</u>

Q. HOW IS WEATHER MEASURED FOR PURPOSES OF THE FORECAST?

A. Weather is expressed in terms of Heating Degree Days (HDD) and Cooling Degree Days (CDD).

Q. WHAT IS A HEATING DEGREE DAY AND A COOLING DEGREE DAY?

A. An HDD is calculated using a base temperature measured on the Fahrenheit scale and occurs when the daily average temperature is below the base. HDD measures the difference of the daily average temperature and the base temperature. The formula is:

Heating Degree Days = Base Temperature – Daily Average Temperature

A CDD is also calculated using a base temperature measured on the Fahrenheit scale. However, it occurs when the daily average temperature is above the base. CDD measures the difference of the daily average temperature and the base temperature. The formula is:

Cooling Degree Days = Daily Average Temperature – Base Temperature

Any negative result of these calculations is taken to be zero.

Q. PLEASE EXPLAIN "NORMAL" WEATHER.

A. The energy forecast projects Duke Energy Kentucky's volume sales for the test period. In order to project this, one must make a judgment about the weather conditions expected to occur during the test period. This is known as "normal" weather. The forecast is based on such expected weather conditions, which are forecast from historical weather data. Because this forecast is forward-looking and intended to predict what is likely to happen in the future, an assumption must be made as to what impact weather is likely to have on future volume sales. There is no "actual" weather available for a future period; so, a projection must be used. A reasonable, accepted and industry standard methodology to factor the impact of weather is to use an average of prior actual weather to predict what future weather patterns are likely to be experienced.

Q. PLEASE DESCRIBE HOW DUKE ENERGY KENTUCKY CALCULATED NORMAL WEATHER.

A. Duke Energy Kentucky uses a rolling 30-year period to calculate the normal weather in its electric and natural gas forecasts.

Q. DOES THE NATIONAL OCEANIC AND ATMOSPHERIC ADMINISTRATION ("NOAA") PROVIDE NORMAL WEATHER DATA FOR DUKE ENERGY KENTUCKY'S SERVICE AREA?

A. Yes. NOAA is responsible for monitoring climate conditions in the United States. Additional information about NOAA is available at their web site at www.noaa.gov. The standard time period prescribed by the United Nations World Meteorological Organization for measuring climate conditions is thirty years, and NOAA updates its calculations for the United States for these thirty-year periods at the end of each decade. The most current thirty-year period used by NOAA is 1991-2020.

Because of its infrequent updates, Duke Energy Kentucky's forecast does not use the NOAA calculations. Rather, the Company uses more recent weather data in performing its forecasts, rolling in the latest year available at the time of the forecast.

Q. WHAT YEARS ARE USED TO CALCULATE THE ROLLING 30-YEAR WEATHER NORMAL FOR THE MOST RECENT DUKE ENERGY KENTUCKY ELECTRIC FORECAST?

A. As a new year of weather data—subject to a delay—becomes available, it is our practice to roll off the oldest year and replace it. The years 1994-2023 were used to calculate normal weather for Duke Energy Kentucky's most recent electric forecast.

Q. WHAT HAS BEEN THE LONG-TERM TREND IN AVERAGE TEMPERATURES FOR COVINGTON, KENTUCKY?

A. The years 1994 through 2023 suggest a slight warming trend. Simple linear trend regression analysis confirms that this trend is statistically significant under several different specifications. The graph in Attachment IAK-4 shows these charts.

Q. WHAT HAS BEEN THE TREND IN HDD AND CDD FOR COVINGTON, KENTUCKY, OVER THE LAST 10 YEARS?

A. Over the last 10 years, the trend in HDD and CDD is similar to the pattern observed over the previous 30 years. However, the trend is statistically insignificant.

Q. HOW DO THE ACTUAL ANNUAL HDDS FOR THE LAST 10 YEARS FOR COVINGTON, KENTUCKY, COMPARE TO 30-YEAR NORMALS?

A. See Attachment IAK-5 for a graph comparing the annual degree days in heating/cooling to the forecasts of the thirty-year normal scheme, as well as the 10-year normal scheme and the NOAA static 30-year normal. The 10-year normal calls for slightly more extreme summer weather (cooling degree days) than the 30-year normal. Annual weather is much more variable than the degree to which the various forecasts vary from each other. The difference between the 10-year normal and 30-year normal is not as dramatic with regard to winter weather (heating degree days), wherein both methods for calculating normal weather appear to be similar upon visual inspection.

IV. DUKE ENERGY KENTUCKY'S UEE/LOAD MANAGEMENT PROGRAMS

Q. WHAT HAS BEEN THE IMPACT OF THE COMPANY'S UEE PROGRAMS ON THE LOAD FORECAST?

A. From 2020 through 2023, the Company's UEE programs are estimated to have reached an annual incremental savings level of nearly 15,000MWh and reduced the summer peak load by—in some cases—as much as 2.4MW.

Q. PLEASE BRIEFLY DESCRIBE DUKE ENERGY KENTUCKY'S CURRENT PORTFOLIO OF UEE AND LOAD CONTROL PROGRAMS.

A. Duke Energy Kentucky offers its customers multiple regulated UEE (EE and DSM) related services and products, as well as low-income assistance programs within the Commonwealth of Kentucky. The various UEE are vetted through one of two collaborative processes (residential and industrial) before being submitted to the Commission for review and approval. Duke Energy Kentucky recovers its costs and receives compensation for these services pursuant to its Commission-approved DSM tariffs. The current suite of programs includes the following:

- Program 1: Residential Energy Assessments Program
- Program 2: Income Qualified Services
- Program 3: Income Qualified Neighborhood Energy Saver
- Program 4: Home Energy Report
- Program 5: Power Manager® Program

The Commission has approved each of these programs and reviews the costs and results of these programs on an annual basis.

Q. WAS THE LOAD FORECAST MODIFIED TO ACCOUNT FOR FUTURE IMPACTS OF ALL OF THESE DSM/UEE PROGRAMS?

A. Yes, it was. The forecast produced by the econometric models was modified by taking UEE program forecasts and subtracting their volume accordingly. In addition, the cumulative impact of these programs was mitigated by a roll-off schedule that accounts for the fact that codes and standards organically evolve in ways that would naturally reduce energy usage over time.

V. FILING REQUIREMENTS AND INFORMATION SPONSORED BY WITNESS

Q. PLEASE DESCRIBE FR 16(7)(h)(5).

A. FR 16(7)(h)(5) consists of the load forecast, which I described earlier in my testimony.

Q. DID YOU SUPPLY ANY INFORMATION TO OTHER WITNESSES IN THIS PROCEEDING?

A. Yes, I supplied Mr. Carpenter with the gas Mcf and electric kWh sales for the forecasted portion of the base period, consisting of the twelve months ending February 28, 2025, and the forecasted test period, consisting of the twelve months ending June 30, 2026.

Q. DO YOU BELIEVE THE FORECAST IS A REASONABLE AND ACCURATE DEPICTION OF THE COMPANY'S ANTICIPATED FUTURE ELECTRIC LOAD?

A. Yes.

VI. CONCLUSION

Q. WERE FR 16(7)(h)(5), THE INFORMATION YOU PROVIDED TO MR. CARPENTER AND ATTACHMENTS IAK-1 THROUGH IAK-5 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

STATE OF Texas)
) SS:
COUNTY OF Collin)

The undersigned, Ibrar A. Khera, Lead Load Forecasting Analyst, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

Ibrar A. Khera Affiant 12/02/2024

Subscribed and sworn to before me by Ibrar A. Khera on this 2nd day of december 2024.

12/02/24

SNEHALBEN PATEL
Notary Public, State of Texas
Comm. Expires 02-02-2028
Notary ID 134744099

S. P. Patel

S. P. Patel
NOTARY PUBLIC

My Commission Expires: 02-02-2028

Duke Energy Kentucky
RankSort Normal Degree Days (on day of Peak) (a,b)

	Forecast Day of Peak	Heating Degree Days	Implied Average Temp	Cooling Degree Days	Implied Average Temp
1/1/2024	1/18/2024	50.92	8.08	--	--
2/1/2024	2/5/2024	39.54	19.46	--	--
3/1/2024	3/4/2024	25.19	33.81	--	--
4/1/2024	4/18/2024	--	--	5.8	70.8
5/1/2024	5/30/2024	--	--	5.79	70.79
6/1/2024	6/25/2024	--	--	10.53	75.53
7/1/2024	7/19/2024	--	--	18.6	83.6
8/1/2024	8/2/2024	--	--	16.54	81.54
9/1/2024	9/3/2024	--	--	8.18	73.18
10/1/2024	10/3/2024	9.24	49.76	--	--
11/1/2024	11/27/2024	30.65	28.35	--	--
12/1/2024	12/19/2024	33.06	25.94	--	--

DUKE ENERGY KENTUCKY
SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS) (a)

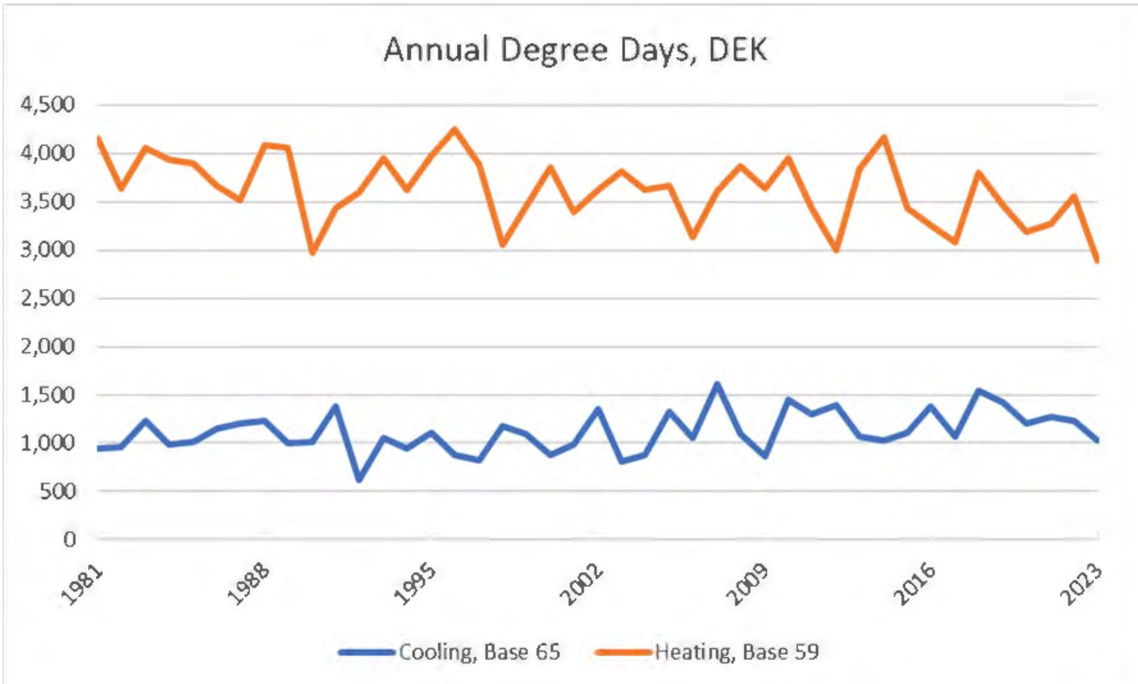
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
								(1+2+3+4+5+6)
	YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET-HWY LIGHTING	OPA	OTHER	TOTAL CONSUMPTION
-5	2019	1,512,664	1,460,450	817,559	13,759	275,132	928	4,080,492
-4	2020	1,477,914	1,416,427	746,182	13,827	187,140	591	3,842,080
-3	2021	1,516,485	1,536,653	751,561	13,143	150,835	666	3,969,344
-2	2022	1,489,339	1,416,933	736,091	12,832	231,056	1,071	3,887,322
-1	2023	1,413,744	1,473,510	743,822	12,163	226,279	325	3,869,842
0	2024	1,521,775	1,460,036	727,962	12,474	250,269	266	3,972,782
1	2025	1,531,911	1,429,597	742,085	12,606	252,077	329	3,968,605
2	2026	1,533,956	1,436,236	741,214	12,424	250,586	329	3,974,746
3	2027	1,538,474	1,430,971	738,074	12,248	249,189	329	3,969,285
4	2028	1,547,199	1,431,949	735,053	12,079	248,069	329	3,974,678
5	2029	1,547,804	1,426,981	732,952	11,916	247,225	329	3,967,206
6	2030	1,552,517	1,497,937	732,201	11,758	246,687	329	4,041,428
7	2031	1,559,522	1,497,984	732,520	11,605	246,374	329	4,048,334
8	2032	1,572,058	1,503,791	732,937	11,456	246,082	329	4,066,652
9	2033	1,582,593	1,503,765	732,844	11,313	245,688	329	4,076,532
10	2034	1,598,235	1,508,308	731,698	11,173	245,112	329	4,094,855
11	2035	1,617,342	1,588,063	730,311	11,173	244,476	329	4,191,694
12	2036	1,642,840	1,599,382	727,719	11,173	243,591	329	4,225,034
13	2037	1,661,427	1,601,837	723,190	11,173	242,325	329	4,240,280
14	2038	1,683,929	1,609,048	718,580	11,173	241,046	329	4,264,105
15	2039	1,707,174	1,616,024	714,382	11,173	239,830	329	4,288,912
16	2040	1,733,954	1,630,395	716,711	11,173	239,849	329	4,332,412
17	2041	1,747,994	1,634,757	718,955	11,173	239,878	329	4,353,085
18	2042	1,766,815	1,644,617	721,375	11,173	239,958	329	4,384,267
19	2043	1,787,850	1,655,959	723,965	11,173	240,070	329	4,419,346
20	2044	1,815,023	1,672,505	726,783	11,173	240,208	329	4,466,021

(a) Figures in years -5 through -1 reflect the impact of historical demand side programs

Duke Energy Kentucky
SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) (a,b)

		SUMMER			WINTER (e)		
	YEAR	LOAD	CHANGE (c)	PERCENT CHANGE (d)	LOAD	CHANGE (c)	PERCENT CHANGE (d)
-5	2019	849			821		
-4	2020	809	-40	-4.9%	742	-79	-9.6%
-3	2021	838	29	3.9%	678	-64	-8.6%
-2	2022	831	-7	-1.0%	710	32	4.7%
-1	2023	834	3	0.4%	810	100	14.1%
0	2024	808	-26	-3.2%	748	-62	-7.7%
1	2025	810	2	0.2%	737	-11	-1.5%
2	2026	812	3	0.3%	738	1	0.1%
3	2027	812	0	0.0%	740	2	0.3%
4	2028	812	0	0.0%	740	1	0.1%
5	2029	812	0	0.0%	739	-1	-0.1%
6	2030	822	10	1.2%	747	8	1.0%
7	2031	827	5	0.7%	749	3	0.3%
8	2032	831	4	0.5%	746	-3	-0.4%
9	2033	838	7	0.9%	755	9	1.2%
10	2034	844	5	0.7%	759	4	0.6%
11	2035	862	18	2.2%	774	15	1.9%
12	2036	872	10	1.2%	777	3	0.4%
13	2037	882	10	1.2%	779	1	0.2%
14	2038	892	10	1.1%	778	-1	-0.1%
15	2039	902	10	1.2%	798	20	2.6%
16	2040	910	8	0.9%	808	10	1.3%
17	2041	916	7	0.7%	808	0	-0.1%
18	2042	930	14	1.5%	813	6	0.7%
19	2043	942	12	1.3%	816	3	0.4%
20	2044	954	12	1.3%	818	1	0.1%

(a) Figures in years -5 through -1—which are not weather-normalized reflect the impact of historical demand side programs.
(b) Includes interruptible and demand response load.
(c) Difference between reporting year and previous year.
(d) Difference expressed as a percent of previous year.
(e) Winter load reference is to peak loads which occured in the following winter.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4,000
3,500
3,000
2,500
2,000
1,500
1,000
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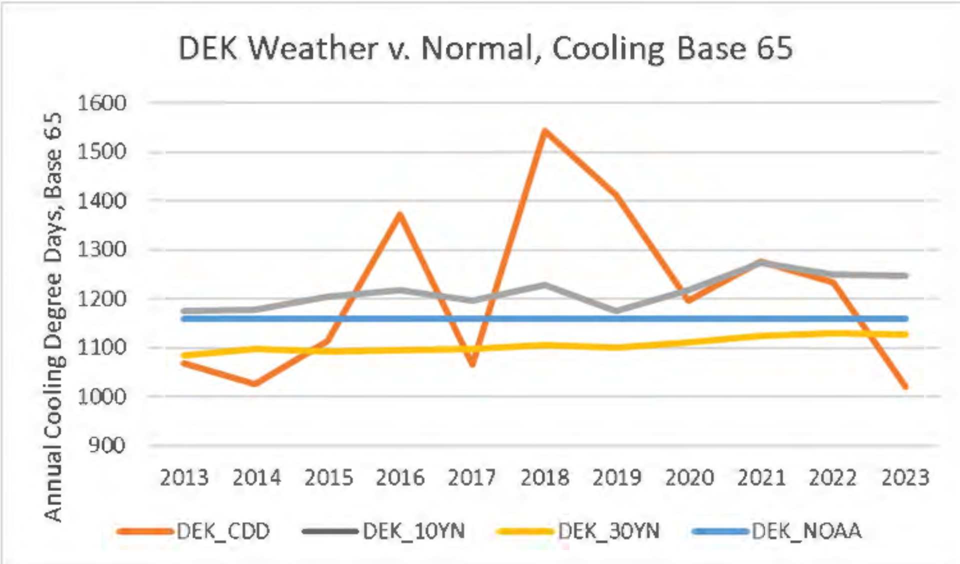
1981
1988
1995
2002
2009
2016
2023
Cooling, Base 65
Heating, Base 59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Annual Cooling Degree Days, Base 65
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1500
1400
1300
1200
1100
1000
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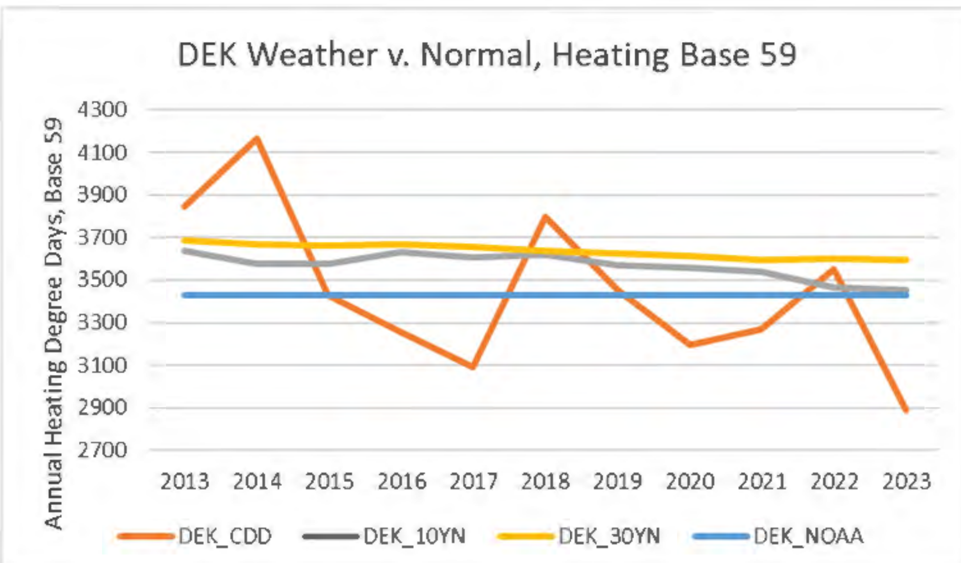
2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023
DEK_CDD
DEK_10YN
DEK_30YN
DEK_NOAA


DEK Weather v. Normal, Heating Base 59
Annual Heating Degree Days, Base 59
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4100
3900
3700
3500
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2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023
DEK_CDD
DEK_10YN
DEK_30YN
DEK_NOAA

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. 2024-00354

DIRECT TESTIMONY OF

SARAH E. LAWLER

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 2, 2024

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PAGE

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Sarah E. Lawler, and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS), as Vice President, Rates and Regulatory Strategy for Ohio and Kentucky. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Science in Accountancy from Miami University, Oxford, Ohio, in 1993. I am also a Certified Public Accountant. I began my career in September 1993 with Coopers & Lybrand, L.L.P., as an audit associate and progressed to a senior audit associate. In August 1997, I moved to Kendle International Inc., where I held various positions in the accounting department, ultimately being promoted to Corporate Controller. In August 2003, I began working for Cinergy Corp., the parent of Duke Energy Ohio, as External Reporting Manager, where I was responsible for the Company’s Securities & Exchange Commission filings. In August 2005, I moved into the role of Manager, Budgets & Forecasts. In June 2006, following the merger between Cinergy Corp. and Duke Energy, I became Manager, Financial Forecasting. In February 2015, I was promoted to Utility Strategy Director, Midwest, where I was responsible for the preparation of business plans and other internal managerial reporting for Duke Energy Kentucky and Duke Energy Ohio. In December 2017, I assumed the role of Director, Rates and Regulatory Planning where I was responsible for the preparation of financial and accounting data used in Duke Energy Kentucky and Duke Energy Ohio retail rate filings and changes in various other rate recovery mechanisms. In May 2020, I was promoted to my current role of Vice President, Rates & Regulatory Strategy where I am responsible for all state and federal regulatory rate matters involving Duke Energy Kentucky and Duke Energy Ohio.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION (COMMISSION)?

A. Yes. I have previously testified in a number of cases before the Commission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THESE PROCEEDINGS?

A. On behalf of Duke Energy Kentucky, I provide some background for its request to increase electric base revenues and the drivers behind the Company’s application. I support the reasonableness of the Company’s proposed rate increase and sponsor Filing Requirements (FR) 16(1)(b)(1) and FR 16(9) to comply with the Commission’s filing requirements. I support the Company’s proposal to reestablish the Company’s deferrals for planned outage operating and maintenance (O&M) expense and forced outage purchased power expense.

II. BACKGROUND AND DRIVERS FOR REQUESTED RATE INCREASE

Q. WHEN DID THE COMMISSION APPROVE DUKE ENERGY KENTUCKY'S CURRENT ELECTRIC RATES?

A. The Company's current base rates for electric service were initially approved by the Commission on October 12, 2023, and then amended upon rehearing on July 1, 2024 in Case No. 2022-00372 (2022 Rate Case).[1] The test period in that proceeding was the forecasted twelve months ended June 30, 2024 and the rate base used in that case was the thirteen-month average for the period ending June 30, 2024. The rates from that case went into effect on October 13, 2023, and then were updated upon rehearing on July 1, 2024.

Q. WHAT PERIOD IS DUKE ENERGY KENTUCKY USING FOR ITS FORECASTED TEST PERIOD IN THIS CASE?

A. The Company's Application in this case requests an increase in its overall electric base revenues based on the forecasted twelve-month period July 1, 2025, through June 30, 2026.

Q. WHY IS DUKE ENERGY KENTUCKY FILING AN ELECTRIC BASE RATE CASE AT THIS TIME?

A. For the forecasted test period, the Company is projecting that the earned return on its investment in its electric distribution system is not sufficient to continue supporting investments necessary to maintain reliable service for customers as it is not providing fair and reasonable compensation to its investors. As a result, the

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[1] *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, Order (Oct. 12, 2023).

Company is requesting an approximate $70 million increase in electric base revenues in order to provide fair and reasonable compensation to its investors.

A significant driver of this requested increase is an increase in the Company's rate base as compared to that in the last rate case. Rate base has grown $157 million since the Company's last rate case as a result of much needed investments for the Company to continue to provide safe and reliable service to its Kentucky customers. The return on this rate base, along with the associated depreciation expense, is the most significant driver of this case.

While depreciation expense is partly higher as a result of this rate base growth since the time of the last electric base rate case, it is also higher for two other reasons. One, as discussed by witnesses Luke, Kalemba, Swez, and Spanos, the Company is proposing to align the depreciable life of East Bend with the estimated useful life of the asset. Based on the Company's 2024 integrated resource plan (IRP), the Company currently estimates East Bend to retire as of December 31, 2038. Finally, depreciation expense is also higher as the Company has included terminal net salvage for East Bend and Woodsdale in its depreciation rates proposed in this case.

Q. WHY IS THE COMPANY INCLUDING TERMINAL NET SALVAGE FOR EAST BEND AND WOODSDALE IN ITS DEPRECIATION RATES IN THIS CASE?

A. An important tenet of ratemaking principles is cost causation, which strives to align the cost of service with the customers who benefit from that service. It is imperative that terminal net salvage be included in customer rates today so that those customers who are benefiting from East Bend and Woodsdale generation are paying for the full costs associated with the facility. If this does not occur, future customers will pay for these costs and significant intergenerational subsidies will exist. And these customers will be burdened with these costs plus the costs of new generation. Unfortunately, these subsidies are currently being created as a result of the Commission's order in the Company's 2022 rate case that removed these historically recovered costs from depreciation rates. The Commission has the opportunity in this case to ensure that cost recovery is aligned with principles of cost causation, to avoid intergenerational inequity, and to avoid leaving future customers with a steep bill when the facilities in question retire and also must be replaced. Put differently, whether to include terminal net salvage costs in rates is not dependent on earlier or later retirement of a facility; it is a function of recognizing that all generation facilities will retire at some point and that it is appropriate to ensure the rates charged to customers benefiting from the facility include costs associated with decommissioning and salvage while the facility is operating.

Q. WHY DID THE COMMISSION REMOVE TERMINAL NET SALVAGE FOR EAST BEND AND WOODSDALE IN THE COMPANY'S LAST ELECTRIC RATE CASE?

A. The Commission found that "terminal net salvage should be removed from the depreciation rates due to the requirements of KRS 278.264(2) that the Commission 'shall not…take any other action which authorizes or allows for the recovery of costs for the retirement of an electric generating unit… unless the presumption created by this section is rebutted.'"

Q. HAS THE COMPANY PROVED THE REBUTTABAL PRESUMPTION IN THIS PROCEEDING?

A. Yes. As outlined in the testimonies of Messrs. Luke, Swez, and Kalemba, and as I explain further below, the presumption created by KRS 278.264 has been rebutted by the Company.

Q. CAN YOU SUMMARIZE HOW THE COMPANY HAS MET THE REBUTTALBAL PRESUMPTION CREATED BY KRS 278.264?

A. Yes. Based upon my years of experience in Kentucky regulatory matters before the Commission, my familiarity with Kentucky rate making policy and the Commission's Order in the Company's 2022 rate case, as I understand it, KRS 278.264 creates a threshold of criteria that the utility must demonstrate before it can retire a generating asset that is fueled by fossil fuel. It provides, in relevant part, that in order to retire a generating unit, the utility must demonstrate, and the Commission must find the following:

> **(a)** The utility will replace the retired electric generating unit with new electric generating capacity that:
>
> > **1.** Is dispatchable by either the utility or the regional transmission organization or independent system operator responsible for balancing load within the utility's service area;
> >
> > **2.** Maintains or improves the reliability and resilience of the electric transmission grid;
> >
> > **3.** Maintains the minimum reserve capacity requirement established by the utility's reliability coordinator; and
> >
> > **4.** Has the same or higher capacity value and net capability, unless the utility can demonstrate that such capacity value and net capability is not necessary to provide reliable service;

> **(b)** The retirement will not harm the utility's ratepayers by causing the utility to incur any net incremental costs to be recovered from ratepayers that could be avoided by continuing to operate the electric generating unit proposed for retirement in compliance with applicable law;
>
> **(c)** The decision to retire the fossil fuel-fired electric generating unit is not the result of any financial incentives or benefits offered by any federal agency; and
>
> **(d)** The utility shall not commence retirement or decommissioning of the electric generating unit until the replacement generating capacity meeting the requirements of paragraph (a) of this subsection is fully constructed, permitted, and in operation, unless the utility can demonstrate that it is necessary under the circumstances to commence retirement or decommissioning of the existing unit earlier.[2]

Company witnesses Luke, Swez and Kalemba explain in their testimony that the Company will replace East Bend and Woodsdale with generation that will be dispatchable by PJM and will at a minimum maintain the reliability and resilience of the electric transmission grid. They further explain that any replacement will maintain necessary reserve capacity requirements established by PJM and will have the same or higher capacity value of East Bend and Woodsdale currently. Witnesses Luke and Kalemba also explain that the decision to retire is not based on any financial incentives or benefits offered by any federal agency. I explain above that the inclusion of terminal net salvage costs in depreciation expense will not result in any net ***incremental*** costs that could be avoided by continuing to operate East Bend and Woodsdale. There are no incremental costs to be incurred. The costs to decommission these plants exists and including these costs in depreciation rates today does not result in incremental net costs to the customer. Additionally, as Mr. Kalemba explains, the Company's IRP demonstrates the

[2] KRS 278.264

Company's approach to retire East Bend is the least cost to customers. Finally, Messrs. Luke and Kalemba also explain that the Company will not commence retirement or decommissioning of East Bend or Woodsdale before the replacement generation capacity meeting the requirements of KRS 278.264 is fully constructed, permitted and in operation.

Q. HAS THE COMMISSION APPROVED THE INCLUSION OF TERMINAL NET SALAVAGE IN DEPRECIATION RATES IN PREVIOUS CASES?

A. Yes. This very issue was litigated in a prior Duke Energy Kentucky electric base rate proceeding, Case No. 2017-00321 (2017 Electric Rate Case).[3] In finding in favor of continuing recovery of terminal net salvage expense through base rates, the Commission found that "Dukes[sic] Kentucky's recommendation on the treatment of terminal net salvage value in the computing the depreciation rates for generating units is reasonable in order to avoid intergenerational inequity and should be approved."[4]

Q. IS THE COST OF CAPITAL ALSO CONTRIBUTING TO THE OVERALL BASE RATE INCREASE?

A. Yes. The cost of capital has increased since the Company's last rate case. The Company's current weighted average cost of capital approved in the 2022 rate case is 7.192 percent. The Company is requesting a weighted average cost of capital of 7.968 percent in this current proceeding. The return on equity (ROE) authorized in

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[3] *In the Matter of the Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of new Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief,* Case No. 2017-00321, Order (April 13, 2018).
[4] *Id.*, p. 27.

the last electric rate case was 9.75 percent. The long-term debt rate approved in that case was 4.377 percent and the short-term debt rate approved was 4.739 percent. In this proceeding, the Company is requesting a ROE of 10.85 percent, a 4.929 percent long-term debt rate and a 3.197 percent short-term debt rate. Company witnesses Joshua C. Nowak and Thomas Heath discuss the market drivers behind these increases in the Company's cost of capital.

Q. PLEASE DESCRIBE HOW THE COMPANY'S REQUESTED INCREASE IN BASE RATES WILL IMPACT CUSTOMERS' BILLS.

A. The Company's proposed overall revenue requirement is an increase of approximately 14.7 percent over current total retail revenue.[5] As discussed in the testimony of Company witness James E. Ziolkowski, Duke Energy Kentucky is proposing to allocate the overall revenue requirement so that existing subsidies and excesses between rate classes are not exacerbated, but rather reduced where possible. As a result of the cost-of-service study, the allocation of the proposed revenue requirement is such that residential customers will see an approximate 16.2 percent increase in their overall bills. Non-residential distribution customers will see an approximate 14.1 percent increase in their bills on average, and non-residential transmission customers will see an approximate 8.0 percent increase on their bills.

[5] *See* Schedule M, page 1 of 1, line 37.

III. PROPOSED DEFERRALS

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO RE-INSTITUTE CERTAIN DEFERRALS AS A PART OF THIS RATE CASE.

A. Duke Energy Kentucky is requesting approval to create two regulatory deferrals for the differences between the actual amounts incurred for certain costs and the amounts established in base rates for those costs in this proceeding. The first deferral proposed will allow the Company to defer actual O&M expenses related to planned outages above or below the baseline amount being recovered in base rates. The second deferral will allow the Company to defer the actual forced outage purchased power expense that is above or below the baseline amount being recovered through the Company's fuel adjustment clause or in base rates as established in this case.

Q. PLEASE DESCRIBE HOW THE COMPANY HAS ESTABLISHED BASELINE AMOUNTS FOR THESE COSTS IN THIS CASE.

A. The Company's forecasted test year for planned outage O&M expense and forced outage purchased power costs for East Bend and Woodsdale have been adjusted to reflect a representative (i.e., average) level of expense. Planned outage O&M expense has been normalized based upon four years of actual expenses and four years of projected expenses. Forced outage purchased power costs have been normalized based upon three years of actual forced outage purchased power not recovered in the FAC. Permitting the Company to defer for future recovery any incremental amount over or under what is established in base rates for these two expenses will ensure that customers are not over paying and the Company is not under recovering for actual costs incurred in serving customers.

Q. CAN YOU EXPLAIN FURTHER WHY THIS OVERALL APPROACH IS APPROPRIATE?

A. Yes. The Commission has exercised its discretion to approve regulatory assets where a utility has incurred: (1) an extraordinary, nonrecurring expense which could not have reasonably been anticipated or included in the utility's planning; (2) an expense resulting from a statutory or administrative directive; (3) an expense in relation to an industry sponsored initiative; or (4) an extraordinary or nonrecurring expense that over time will result in a savings that fully offsets the costs.

The costs for which the Company is seeking to create the regulatory deferrals represent incremental costs or savings compared to normalized levels, and as such they effectively constitute extraordinary non-recurring expenses (or savings) that could not have reasonably been anticipated or included in the utility's planning. Further, as discussed by Company witnesses William Luke and John Swez, the actual costs of these items are unable to be reasonably planned or anticipated – particularly for forced outages, which by definition are not pre-planned. The deferrals protect customers from overpaying for these costs when the utility's actual costs incurred are below the levels used to establish base rates, and conversely ensures the Company can recover its actual costs when the actual costs incurred are higher than those used to establish base rates.

The table below shows the eight-year average (four-year historical and four-year forecast) of planned outage O&M and depicts the volatility of these costs.

Year	Description	East Bend	Woodsdale	Total	CPI 2023= 100 (A)	Total
2020	Planned Outage O&M	$ 6,916,095	$ 845,490	$ 7,761,585	84.9%	$ 9,142,032
2021	Planned Outage O&M	10,409,808	638,725	11,048,533	90.9%	12,154,602
2022	Planned Outage O&M	7,960,822	464,577	8,425,399	96.8%	8,703,925
2023	Planned Outage O&M	11,408,243	716,017	12,124,260	100.0%	12,124,260
2024	Planned Outage O&M	4,122,034	462,340	4,584,374	100.0%	4,584,374
2025	Planned Outage O&M	8,228,256	2,685,000	10,913,256	100.0%	10,913,256
2026	Planned Outage O&M	8,191,270	4,570,000	12,761,270	100.0%	12,761,270
2027	Planned Outage O&M	1,262,177	2,420,000	3,682,177	100.0%	3,682,177
	8 Year Average			$ 8,912,607		$ 9,258,237

The table below shows the three-year historical average of forced outage purchased power not recovered in the FAC and depicts the volatility of these costs.

Line No.	Description	2023	2022	2021	Average
1	Cost of Purchased Power due to Forced Outage	4,537,208	10,932,275	8,264,605	7,911,363
2	Cost of Purchased Power Recovered Through FAC	4,537,208	3,710,050	4,674,065	4,307,108
3	Cost of Purchased Power Deferred in Reg Asset	0	7,222,225	3,590,540	3,604,255

Because Duke Energy Kentucky is relatively small, the swings from year to year in these expenses cause volatility in the Company's earnings. The proposed deferrals are designed so that, over time, the balance should approach $0 but will prevent these two volatile cost items from having a significant influence on the Company's earnings.

Q. HAS THIS COMMISSION PREVIOUSLY OR RECENTLY APPROVED SIMILAR DEFERRALS FOR ELECTRIC UTILITIES?

A. Yes. Notably, in 2018, the Commission approved Duke Energy Kentucky's request for a deferral mechanism for actual planned outage expense that was more or less than the normalized planned outage expense included in its base rates.[6] The

[6] *In the Matter of the Electronic Application of Duke Energy Kentucky, Inc. for (1) An Adjustment of the*

Commission has also approved similar deferral mechanisms for extraordinary expenses in other cases. In 2008, the Commission authorized East Kentucky Power Cooperative, Inc. (East Kentucky) to establish a regulatory asset for its unrecovered replacement power costs related to the forced outages of its generating units that were not eligible for recovery through East Kentucky's fuel adjustment clause.[7] Thus, there is precedent for Duke Energy Kentucky's proposed deferral mechanisms.

IV. <u>REASONABLENESS OF REQUEST</u>

Q. IS THE COMPANY'S REQUESTED RATE RELIEF REASONABLE?

A. Yes. Duke Energy Kentucky has worked very hard to keep its expenses reasonable over the years; however, the need to continually invest in its electric generation, transmission, and distribution system creates a need for the Company to seek additional rate relief. The need to update depreciation rates so that the depreciable lives align with the service lives of assets is also imperative so that cross-generation subsidization does not occur, and future customers are not left with the burden of paying twice: once for significant amounts of post-retirement undepreciated plant remaining after the generating assets' retirements, and twice for their replacement

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Electric Rates; (2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; (3) Approval of New Tariffs; (4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and (5) All Other Required Approvals and Relief, Case No. 2017-00321, Order, p. 79 (Apr. 13, 2018).

[7] *In re: Application of East Kentucky Power Cooperative, Inc. for an Order Approving Accounting Practices to Establish a Regulatory Asset Related to Certain Replacement Power Costs Resulting from Generation Forced Outages*, Case No. 2008-00436, (Dec. 23, 2008).

resource(s). Further, it is important to update the Company's costs, revenues, cost of capital, and rates from time to time to support the financial health of the business.

V. FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE FR 16(1)(b)(1).

A. FR 16(1)(b)(1) is Duke Energy Kentucky's statement of the reasons for the proposed increase.

Q. PLEASE DESCRIBE FR 16(9).

A. FR 16(9) is Duke Energy Kentucky's acknowledgement that it understands that its application will not be accepted for filing until it has cured any deficiencies as determined by the Commission.

VI. CONCLUSION

Q. HAVE YOU REVIEWED DUKE ENERGY KENTUCKY'S APPLICATION IN THESE PROCEEDINGS?

A. Yes. I have also reviewed the testimony and attachments of all Company witnesses. I believe that the Company's total electric revenue requirement is properly computed, the costs of service are properly allocated to customer classes, and the rate design is equitable.

Q. DO YOU BELIEVE DUKE ENERGY KENTUCKY'S RATE REQUEST IS REASONABLE?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

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. 2024-00354

DIRECT TESTIMONY OF

WILLIAM C. LUKE

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 2, 2024

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William C. Luke and my business address is 1000 East Main Street, Plainfield, Indiana 46168.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Vice President of Midwest Generation for Duke Energy Business Services, LLC (DEBS). DEBS is a service company subsidiary of Duke Energy Corporation (Duke Energy), which provides services to Duke Energy and its subsidiaries, including Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUNDS.

A. I have a Bachelor of Engineering degree from State University of New York Maritime College and received a Merchant Marine License from the U.S. Coast Guard. I began my career as a licensed maritime engineer and worked for the New York Power Authority and the Brooklyn Navy Yard Cogeneration facility. I have more than 30 years of power generation experience including various leadership roles in operations, strategy, maintenance, startup and commissioning. I joined the Company in 2005 as a production manager at the Hines Energy Complex in Florida and later managed Duke Energy's Anclote, Bartow, Suncoast and Cayuga stations. Next, I became the director of Midwest Environmental Field Support and then General Manager of Regional Services in the Midwest. I assumed my current role in April 2022.

Q. PLEASE SUMMARIZE YOUR DUTIES AS VICE PRESIDENT MIDWEST GENERATION.

A. In this role, I am responsible for providing safe, compliant, and reliable operation of Duke Energy's Midwest generation fleet (Kentucky and Indiana), which includes four coal, one combined cycle, one combined heat and power, one hydro, six simple cycle combustion turbine, and three solar facilities. Combined, these assets provide approximately 7,400 megawatts (MWs) of generation. My primary responsibilities include managing the fleet within design parameters and implementing work practices and procedures that ensure safe and regulatorily compliant operation and maintenance activities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes. Most recently, I provided testimony in Case No. 2022-00372 supporting Duke Energy Kentucky's 2022 electric base rate case.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I describe the Company's two fossil-fueled generating stations, East Bend Generating Station (East Bend) and Woodsdale Combustion Turbines (Woodsdale) (collectively, the Plants). I explain how these Plants are used to provide safe, affordable, reliable, and reasonable electric service to Duke Energy Kentucky's customers and the Company's continued investment in these Plants. I give an update on the decommissioning of the Miami Fort 6 generating unit. I also discuss the three solar stations owned by Duke Energy Kentucky. I discuss the new anticipated retirement date of East Bend as a result of changes in environmental regulations impacting coal-fired generation and associated economics. I then discuss how the Company will eventually replace East Bend in a way that continues to provide the same or better levels of reliability, dispatchability, with sufficient reserves, and operate those future assets to provide safe, reliable, and reasonable service to meet our Kentucky customers' electricity needs. I also support the Company's request to re-institute its planned outage Operating & Maintenance (O&M) expense deferral. Finally, I sponsor part of the information in the capital budget relating to the Plants contained in Filing Requirements (FR) 16(7)(b), FR 16(7)(f), and FR 16(7)(g), which I provided to Duke Energy Kentucky witness Grady "Tripp" S. Carpenter for the forecasted financial data.

II. GENERAL DESCRIPTION OF DUKE ENERGY KENTUCKY'S GENERATING STATIONS

A. East Bend

Q. PLEASE DESCRIBE EAST BEND.

A. East Bend is a 600 MW (net summer rating) coal-fired steam unit located along the Ohio River in Boone County, Kentucky which was commissioned in 1981. The net ratings represent the net amount of power that we can dispatch from the plants after some portion of the gross power output is used to power the plant machinery. East Bend was originally planned for up to four coal-fired units but only one unit (Unit 2) was constructed. The station has river facilities to allow barge deliveries of coal and lime. East Bend is designed to burn eastern bituminous coal and achieved a net plant heat rate of 11,075 Btu/kWh for calendar year 2023. The major pollution control features are a high-efficiency hot side electrostatic precipitator, a selective catalytic reduction control (SCR) system designed to reduce nitrogen oxide (NO_x) emissions by 85 percent, and a Wet Flue Gas Desulfurization (WFGD) system designed to remove sulfur dioxide (SO_2) emissions to an average of 97 percent. The station's electrical output is directly connected to the Duke Energy Midwest (consisting of Kentucky and Ohio) 345 kilovolt (kV) transmission system.

Q. PLEASE DESCRIBE WHAT ACTIONS THE COMPANY IS CURRENTLY DOING TO MAINTAIN RELIABILITY AT EAST BEND.

A. Although East Bend is approaching the end of its service life and the Company plans to replace the asset with other resources, as I describe later in my testimony, it is important to keep the unit in efficient working order to support the energy needs of our customers. Therefore, costs for this asset will continue to be incurred and investments made as appropriate and prudent to ensure that the same reliable, cost-effective electricity that customers have counted on for decades remains available while replacement generation for the unit is developed and implemented.

Duke Energy Kentucky follows regular maintenance schedules at its plants. Generally speaking, the stations have periodic maintenance activities scheduled during off-peak seasons in the spring and/or fall. Typically, outage duration can range from 1 to 12 weeks depending on project scope. Outage and project scopes are determined utilizing various sources and techniques such as condition assessments, operational data, and Original Equipment Manufacturer (OEM) recommendations.

Q. PLEASE BRIEFLY DESCRIBE DUKE ENERGY KENTUCKY'S RECENT CAPITAL INVESTMENTS IN EAST BEND THAT ALLOW IT TO CONTINUE TO OPERATE SAFELY, EFFICIENTLY, AND IN COMPLIANCE WITH ENVIRONMENTAL REQUIREMENTS FOR THE BENEFIT OF CUSTOMERS.

A. In the fall of 2023, the Company executed a seven-week outage at East Bend to perform significant maintenance and improvements to the station's turbine, generator, boiler, WFGD, and material handling systems. The major scope of work associated with this outage included steam turbine valve maintenance and reliability upgrades, replacement of the steam turbine generator trip systems controls, replacement of boiler feed pump controls, and replacement of coal reclaim chutes and scrubber byproduct radial stacker.

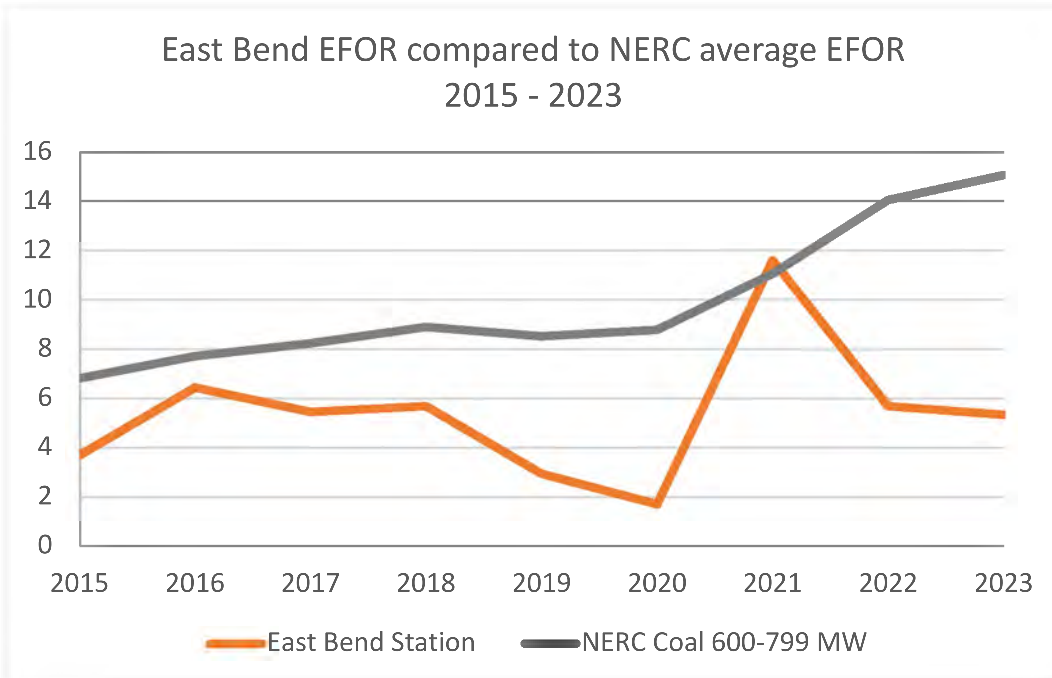
In the fall of 2024, the Company executed a 10-week outage at East Bend to perform significant maintenance and improvements to the station's WFGD, boiler, fuel handling systems, and ancillary systems at the site. The major scope of work associated with this outage included replacement of WFGD ductwork, overhaul of a soot blowing air compressor, coal barge unloader maintenance, and replacement of one section of electrical buswork.

The Company has made other capital investments as necessary outside of these outages to ensure the reliability of the plant. Since the time of the Company's last rate case, investments have been made to rebuild or replace critical equipment such as fuel pulverizers, air compressors, cooling tower equipment, and to implement environmentally required storm water run-off controls.

Q. IS EAST BEND USED AND USEFUL FOR SERVING DUKE ENERGY KENTUCKY'S NATIVE LOAD CUSTOMERS?

A. Yes. East Bend, as described above, has proven to be a reliable generating asset for Duke Energy Kentucky's native load customers. One useful measure of the performance of a coal-fired generating station is the Equivalent Forced Outage Rate (EFOR), which is equal to the hours of unit forced unavailability (unplanned outage hours and equivalent unplanned derated hours) given as a percentage of the total hours of service plus the unavailability of that unit (unplanned outage, unplanned derate, and service hours). For example, if PJM Interconnection LLC (PJM) anticipated a unit to run 1,000 hours in a certain year but the unit was unable to run 100 of those hours due to unexpected problems, the unit's EFOR would be 10%. A low EFOR number is desirable.

The chart below provides a summary of East Bend's EFOR and compares it to the average EFOR reported for North American Electric Reliability Corporation (NERC) coal-fired units over the same period.



As shown in the chart above, East Bend has significantly outperformed the NERC average EFOR for units of similar size in eight of the past nine years. The higher EFOR in 2021 was due to a generator excitation issue. Generator excitation means that, as the load on the generator is increased, an increase in current flow causes the voltage to drop. The excitation system senses this decrease in voltage and increases the strength of the magnetic field to return the voltage to the desired level. This issue was resolved, and the unit was returned to service with no other impacts to generation. The 2024 year-to-date EFOR for East Bend through September is 1.79 percent.

B. <u>Woodsdale</u>

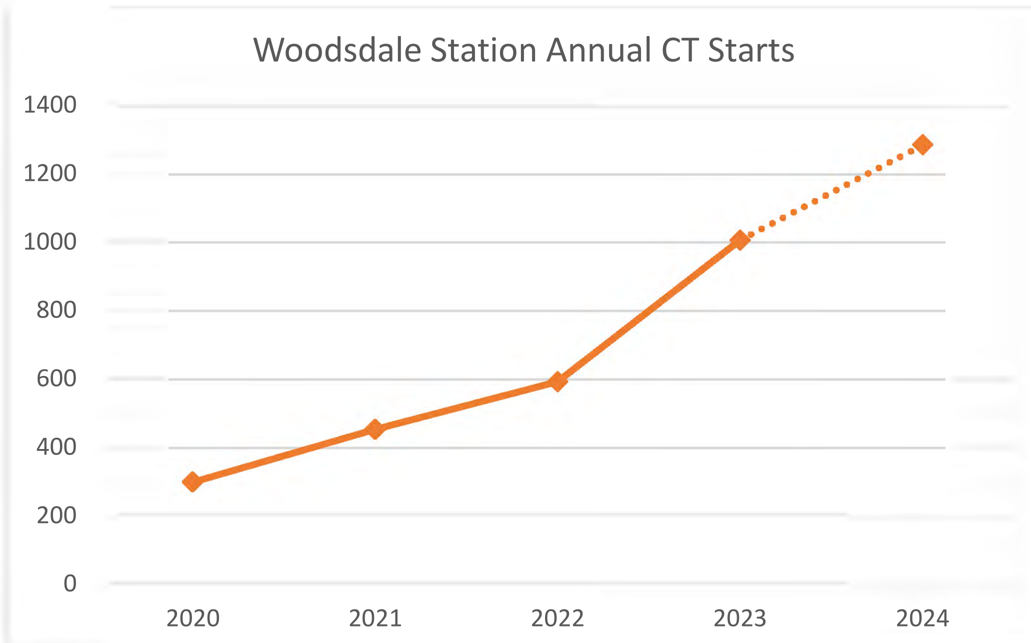
Q. PLEASE DESCRIBE WOODSDALE.

A. Woodsdale is a six-unit, simple cycle, combustion turbine (CT) station located in Butler County, Ohio, just north of Cincinnati, with a collective net winter rating of 564 MW and a net summer rating of 476 MW. Woodsdale is designed to provide peaking service and to have black start and dual fuel capability. Black start capability means that the station has the ability to initiate a recovery of a substantial portion of load without relying on energy from outside sources if the regional grid experiences a blackout. The black start capability is initiated by an Allison 501-KB gas turbine that serves as a back-up power source and allows the station to start generating energy without power from the electric grid. Dual fuel capability is provided through the ability to burn both natural gas and fuel oil. The backup ultra-low sulfur diesel fuel oil (ULSD) system was commissioned in May 2019.

Woodsdale is connected to the Texas Eastern Transmission Company (TETCO) interstate pipeline that transports natural gas to supply the station. By design, Woodsdale's peaking units, with low-capacity factors as compared to baseload units and dual fuel capabilities, does not require securing firm natural gas transportation through the available natural gas interstate pipelines.

Q. PLEASE EXPLAIN WHY WOODSDALE BEING DESIGNED FOR PEAKING CAPABILITY IS SIGNIFICANT.

A. Peaking units, by design, run for short periods to meet peak demand. As a result, peaking units have a much lower capacity factor than baseload or intermediate load units. Woodsdale, like most natural gas CTs are generally dispatched in response to market price signals. These units have great flexibility in terms of operation and can start and ramp up and down quickly in response to changes in the energy markets and system reliability needs. Consequently, their higher production cost versus baseload or intermediate generating assets makes Woodsdale (and all peaking units) lower in the dispatch order. Despite this, Woodsdale has demonstrated the importance of its peaking capabilities to the Duke Energy Kentucky system through the number of CT starts executed annually. Since 2020, the number of CT starts at Woodsdale have significantly increased due to PJM system requirements. The chart below provides a summary of annual CT starts at Woodsdale Station since 2020. Company witness John D. Swez further discusses primary drivers for the increased usage of Woodsdale CTs in the PJM market starts.



Q. PLEASE DESCRIBE WHAT ACTIONS THE COMPANY IS CURRENTLY DOING TO MAINTAIN OR ENHANCE RELIABILITY AT WOODSDALE.

A. Duke Energy Kentucky follows similar periodic maintenance cycles for the Woodsdale units to those of East Bend that I mentioned above. The dual fuel capabilities installed in 2019 provide another option for safe, reliable power from the Woodsdale facility. Since the time of the Company's last rate case, the Company has also made necessary investments to ensure the reliability of the plant some of which include a generator field rewind, and a major turbine inspection and overhaul that is being executed in fall 2024.

C. <u>Solar Facilities</u>

Q PLEASE DESCRIBE THE SOLAR FACILITIES OWNED BY DUKE ENERGY KENTUCKY.

A. Duke Energy Kentucky owns four solar facilities with a total nameplate rating of 8.8 MW: Walton 1 Solar Plant (2 MW) located in Walton, KY.; Walton 2 Solar Plant (2 MW), also located in Walton, KY.; Crittenden Solar Plant (2.8 MW), located in Dry Ridge, KY: and Aero Solar Plant (2 MW), located in Burlington, KY. These four plants combined provide 3.7 MW of firm summer capacity. The Walton and Crittenden Solar sites have commercial operation dates of December 14, 2017, while the Aero Solar site went into commercial operation on March 22, 2023.

D. <u>Miami Fort</u>

Q. PLEASE DESCRIBE THE STATUS OF THE DECOMMISSIONING OF DUKE ENERGY KENTUCKY'S MIAMI FORT 6.

A. Miami Fort 6 officially retired from commercial operation on June 1, 2015. As part of the retirement of this asset, Duke Energy Kentucky is now taking action to make sure that the Miami Fort 6 facilities are decommissioned in a safe and reasonable manner. This includes removing necessary equipment and facilities to minimize safety and environmental hazards. Because of the close proximity of Miami Fort 6 and shared facilities with other Miami Fort station generating Units 7 & 8 owned by Vistra that are still in operation, the Company cannot immediately perform all necessary decommissioning and demolition work. Rather, that work must occur methodically over time so as not to interfere with operation of the other station units or personnel. The majority of the decommission work on Miami Fort 6 was completed from 2018 to 2022. The unit is greater than 90% decommissioned, meaning it has been made environmentally and electrically safe. Since 2022, Duke Energy Kentucky performs maintenance and monitoring of the facility through an Operations and Maintenance agreement (O&M Agreement) with Vistra. This O&M Agreement expires at the end of 2024 and extension of the Agreement through station retirement is anticipated. In 2020, Vistra announced its plans to retire Units 7 & 8 by the end of 2027. The Company will coordinate with Vistra on the decommissioning of Unit 6 at the appropriate time after these retirements take place. There have been no reports of Vistra extending or accelerating the planned retirement date for Units 7 & 8.

III. ANTICIPATED RETIREMENT OF GENERATING PORTFOLIO

Q. WHAT IS THE CURRENT ESTIMATED RETIREMENT DATE FOR EAST BEND?

A. Presently, Duke Energy Kentucky is anticipating that East Bend will retire no later than December 31, 2038, as a result of environmental regulations, namely the United States Environmental Protection Agency's (US EPA) Clean Air Act 111 Update (CAA 111 Update) that limits the operation of existing coal-fired generation. Additionally, there are multiple drivers for this anticipated retirement that could also accelerate the retirement without the CAA 111 Update, most significantly, market pressures that are negatively impacting the long-term viability of coal-fired generation.

As more fully explained by Company witness Matthew Kalemba, Duke Energy Kentucky's most recent Integrated Resource Plan (IRP), filed with the Commission in Case No. 2024-00197, analyzed several scenarios that could impact the Company's resource portfolio. These scenarios drove the development of portfolio possibilities, with the most likely result being East Bend's conversion to dual fuel operation by adding natural gas co-firing capability by 2030. This would allow the unit to continue operating as both a coal-fired unit and a natural gas unit through the end of 2038, the time limit established by the CAA 111 Update for coal-conversions. The Company's previous IRP had contemplated a station retirement by 2035 due to economics. As part of the Company's last base rate case, Case No. 2022-00372, the Commission found that the Company's proposal for depreciation of the unit through 2035 should be rejected due to the Company not satisfying the rebuttable presumption against coal retirement created through KRS 278.264. Mr. Kalemba discusses the recent market conditions and federal regulations that support the current projected life of East Bend.

Q. YOU MENTIONED THE REBUTTABLE PRESUMPTION AGAINST RETIREMENT OF FOSSIL GENERATION, CAN YOU PLEASE EXPLAIN THAT?

A. While I am not an attorney, I am aware of and have reviewed the statute that was put into effect in the spring of 2023 that created the rebuttable presumption against fossil generation retirement in Kentucky. The statute creates a threshold of criteria that the utility must demonstrate before it can retire a generating asset that is fueled by a fossil fuel. It provides, in relevant part, that in order to retire a generating unit, the utility must demonstrate, and the Commission must find the following:

> **(a)** The utility will replace the retired electric generating unit with new electric generating capacity that:
>
> > **1.** Is dispatchable by either the utility or the regional transmission organization or independent system operator responsible for balancing load within the utility's service area;
> >
> > **2.** Maintains or improves the reliability and resilience of the electric transmission grid;
> >
> > **3.** Maintains the minimum reserve capacity requirement established by the utility's reliability coordinator; and
> >
> > **4.** Has the same or higher capacity value and net capability, unless the utility can demonstrate that such capacity value and net capability is not necessary to provide reliable service;
>
> **(b)** The retirement will not harm the utility's ratepayers by causing the utility to incur any net incremental costs to be recovered from ratepayers that could be avoided by continuing to operate the electric generating unit proposed for retirement in compliance with applicable law;

> **(c)** The decision to retire the fossil fuel-fired electric generating unit is not the result of any financial incentives or benefits offered by any federal agency; and
>
> **(d)** The utility shall not commence retirement or decommissioning of the electric generating unit until the replacement generating capacity meeting the requirements of paragraph (a) of this subsection is fully constructed, permitted, and in operation, unless the utility can demonstrate that it is necessary under the circumstances to commence retirement or decommissioning of the existing unit earlier.[1]

Q. IS DUKE ENERGY KENTUCKY SEEKING AUTHORIZATION TO RETIRE EAST BEND IN THIS PROCEEDING?

A. No. The Company is not seeking authorization to retire East Bend in this case. The Company is, however, seeking to adjust its depreciation expense to align with the estimated useful life of the station, which by all evidence, is 2038.

Q. IS KRS 278.264 RELEVANT TO THE DEPRECIABLE LIFE OF THE COMPANY'S FOSSIL GENERATION FLEET IF THE COMPANY IS NOT SEEKING COMMISSION APPROVAL TO RETIRE AND REPLACE THESE ASSETS IN THIS CASE?

A. As part of the Commission's decision in Duke Energy Kentucky's last electric rate case, the Commission referenced the above-quoted statute in deciding against the Company's proposal to align the depreciable life of East Bend to the then modeled

[1] KRS 278.264.

retirement date of 2035. Conversely, the Commission did agree with the Company's proposal to adjust the depreciable life of Woodsdale further into the future. Instead, the Commission held that East Bend's depreciable life should continue to reflect a December 31, 2041 retirement date for several reasons: 1) the Company should be encouraged to operate the station as long as it is economically viable to do so; 2) the Company's 2021 IRP was not a reasonable planning document because the generation retirement study did not adequately support a 2035 retirement date; and that the Company must rebut the presumption against retirement to recover potential stranded asset costs, such as those of an earlier retirement date.[2] Additionally, the Commission further relied upon KRS 278.264 to remove terminal net salvage expense from depreciation expense, because the statute prevents the Commission from taking any action that authorizes or allows for the recovery of costs for the retirement of an electric generating unit unless the presumption against retirement is rebutted.[3]

Q. WHY IS THE COMPANY SEEKING TO ADJUST EAST BEND'S DEPRECIABLE LIFE AGAIN IN THIS CASE?

A. It must be acknowledged that the unit will retire eventually. East Bend, having started commercial operations in the early 1980's, is approaching the end of its useful life. And notwithstanding the CAA 111 Update's viability, the economics of coal generation and compliance obligations are not going to get less expensive (*i.e.,*

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[2] *In the Matter of the Electronic Application of Duke Energy Kentucky, Inc., for (1) An Adjustment of 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, (KY.P.S.C. at 13) (Oct. 12, 2023).
[3] *Id.* pg. 14.

more economic) over time. Maintaining and even extending the life of the station will require significant investments. Indeed, as Mr. Kalemba supports, the Company's current IRP analyzes the likely compliance requirements to keep the unit operational as long as possible, which includes a significant capital investment occurring in the next five years to keep the plant burning coal beyond 2030 and through 2038. Again, notwithstanding whether or not the CAA 111 Update withstands legal challenges, the rule is in effect today, and there will likely be additional restrictions to the operation and/or economics of coal necessitating East Bend's retirement prior to 2041. In order to avoid creation of any more stranded costs, saddling future customers with the unnecessary costs of paying for new and retired generation, and to avoid the inter-generational subsidies created by misaligning asset costs with its operational life, the depreciation expense should be properly sized to recover such costs over the known life of the asset which is currently estimated to retire by December 31, 2038.

Q. HAS DUKE ENERGY KENTUCKY CONSIDERED THE CRITERIA NECESSARY FOR OVERCOMING THE REBUTTABLE PRESUMPTION AGAINST RETIREMENT FOR PURPOSES OF ESTABLISHING NEW DEPRECIATION RATES AND RECOVERING TERMINAL NET SALVAGE EXPENSE AS THE COMMISSION INSTRUCTED IN THE COMPANY'S LAST BASE RATE CASE?

A. Yes. Company witnesses Kalemba, Sarah E. Lawler, Swez, John J. Spanos, and I discuss these criteria more fully.

Q. WHICH CRITERIA ARE YOU SPECIFICALLY ADDRESSING?

A. My testimony focuses on all the operational aspects of the criteria as it relates to the Company's plan to eventually retire and replace East Bend and Woodsdale. I address the criteria with respect to East Bend first before turning to Woodsdale.

Q. PLEASE EXPLAIN HOW THE COMPANY WILL EVENTUALLY RETIRE AND REPLACE EAST BEND?

A. As stated previously, Duke Energy Kentucky is anticipating that East Bend will retire no later than December 31, 2038. As Company witness Kalemba states in his testimony, the 2024 IRP replaces the 600 MW East Bend unit with a 664 MW 1x1 natural gas combined cycle (CC) unit as the optimal replacement resource for East Bend at the time of its retirement. The Company is seeking to include terminal net salvage value in its depreciation expense for East Bend based on the December 31, 2038, retirement date. Company witnesses Spanos and Lawler discuss this further in their testimonies.

Q. WILL THE COMPANY REPLACE EAST BEND WITH AN ASSET THAT IS DISPATCHABLE BY EITHER THE UTILITY OR THE REGIONAL TRANSMISSION ORGANIZATION OR INDEPENDENT SYSTEM OPERATOR RESPONSIBLE FOR BALANCING LOAD WITHIN THE UTILITY'S SERVICE AREA? PLEASE EXPLAIN.

A. Yes, as Company witness Swez addresses in his testimony, the replacement generation can be committed and/or operated to respond to instructions sent by either PJM or the Company as a result of either a change in demand or market prices.

Q. WILL THE COMPANY REPLACE EAST BEND WITH AN ASSET THAT MAINTAINS OR IMPROVES THE RELIABILITY AND RESILIENCE OF THE ELECTRIC TRANSMISSION GRID? PLEASE EXPLAIN.

A. Yes. As Company witness Kalemba states in his testimony, the 2024 IRP represents Duke Energy Kentucky's roadmap to meet future energy and demand requirements without compromising reliability of service. From a practical perspective, replacement of an over 40-year-old asset with a modern, proven technology designed with improved ramp rates and startup capabilities is expected to maintain or improve the reliability and resilience of the electric transmission grid.

Q. WILL THE COMPANY REPLACE EAST BEND WITH AN ASSET THAT MAINTAINS THE MINIMUM RESERVE CAPACITY REQUIREMENT ESTABLISHED BY THE UTILITY'S RELIABILITY COORDINATOR? PLEASE EXPLAIN.

A. Yes. As witness Kalemba discusses in his testimony, the 1x1 CC that is replacing the retiring East Bend asset will contribute the same amount of capacity towards meeting the minimum reserve capacity requirement established by PJM as the existing East Bend unit.

Q. WILL THE COMPANY REPLACE EAST BEND WITH AN ASSET THAT HAS THE SAME OR HIGHER CAPACITY VALUE AND NET CAPABILITY, UNLESS THE UTILITY CAN DEMONSTRATE THAT SUCH CAPACITY VALUE AND NET CAPABILITY IS NOT NECESSARY TO PROVIDE RELIABLE SERVICE.

A. Yes, as Company witnesses Kalemba and Swez detail in their respective testimonies, comparing the existing East Bend asset with the proposed replacement generation is expected to achieve approximately equal capacity value and higher net capability.

Q. CAN YOU CONFIRM THAT THE COMPANY'S DECISION TO EVENTUALLY RETIRE EAST BEND IS NOT THE RESULT OF ANY FINANCIAL INCENTIVES OR BENEFITS OFFERED BY ANY FEDERAL AGENCY?

A. Yes, the decision is not based on any incentive or benefit offered by any federal agency. The Company's decision to retire East Bend in 2038 is driven by the unit's service life, economics, and current environmental regulations that limit the use of coal as a generating fuel. There are no financial incentives offered by any federal agency that are driving the Company's decision. In fact, as Mr. Kalemba supports in his testimony and as demonstrated in the Company's pending IRP, the Company is actually planning on investments at East Bend that will prolong the Company's ability to use coal as a fuel at the station through 2038 as is allowed under the CAA 111 Update. Absent this anticipated investment, under that regulation, the

Company would have to retire the unit much earlier or convert it to 100 percent natural gas operation.

Q. WILL DUKE ENERGY KENTUCKY COMMENCE RETIREMENT OR DECOMMISSIONING OF EAST BEND BEFORE THE REPLACEMENT GENERATING CAPACITY MEETING THE REQUIREMENTS OF KRS 278.264 IS FULLY CONSTRUCTED, PERMITTED, AND IN OPERATION?

A. No. Again, the Company is not seeking authorization to retire and replace East Bend in this case. The Company is simply trying to adjust its depreciation expense to fully recover its costs and avoid the creation of any stranded costs or perpetuate or exacerbate inter-generational subsidies among rate payers. That said, as demonstrated by the Company's IRP, Duke Energy Kentucky has every intention to replace East Bend with another dispatchable, reliable, efficient generating asset to serve its Kentucky customers prior to the retirement of East Bend.

Q. PLEASE EXPLAIN THE FACTORS THAT ARE IMPACTING EAST BEND'S REMAINING SERVICE LIFE.

A. As explained by Company witness Swez, East Bend's energy is sold through the PJM markets. As more energy providers enter the marketplace with lower energy and operations costs, East Bend is projected to be less competitive and called upon to produce energy less frequently. Likewise, as coal prices increase, plants like East Bend will become more unfavorable in the competitive market. In addition to fuel prices, as stations age, maintenance on those stations increases due to wear and tear on the aging equipment. This maintenance cost also contributes to the unfavorable position of the station in the market. Duke Energy Kentucky will attempt to mitigate this exposure to market purchases and volatility to the greatest extent possible for customers.

Q. WHAT IS THE ANTICIPATED RETIREMENT DATE FOR WOODSDALE AND WHAT IS THE COMPANY PROPOSING WITH RESPECT TO WOODSDALE'S DEPRECIABLE LIFE IN THIS CASE?

A. Currently, based upon the performance of the Woodsdale units, their regular maintenance, and the fact that these units are used for peaking service, the Company is maintaining the existing estimated service life of these assets to reflect a retirement date of December 31, 2040. As part of its decision in Case No. 2022-00372, the Commission found that depreciation rates should reflect retirement dates of December 31, 2040, for Woodsdale. The Company is seeking to maintain this depreciable life to remain aligned with the anticipated retirement date of these assets. The Company is seeking to include terminal net salvage value in its depreciation expense for Woodsdale based on the December 31, 2040, retirement date. Company witnesses Spanos and Lawler discuss this further in their testimonies.

Q. HOW WILL DUKE ENERGY KENTUCKY REPLACE WOODSDALE ONCE RETIRED?

A. As Company witness Kalemba states in his testimony, while the replacement of Woodsdale was not evaluated as part of the 2024 IRP, upon its retirement the Company anticipates replacing Woodsdale with similarly dispatchable firm capacity, compliant with all Kentucky legislation or statutes in place at that time.

Q. WILL THE COMPANY REPLACE WOODSDALE WITH AN ASSET THAT IS DISPATCHABLE BY EITHER THE UTILITY OR THE REGIONAL TRANSMISSION ORGANIZATION OR INDEPENDENT SYSTEM OPERATOR RESPONSIBLE FOR BALANCING LOAD WITHIN THE UTILITY'S SERVICE AREA? PLEASE EXPLAIN.

A. Yes, the Company intends that the replacement generation for Woodsdale can be committed and/or operated to respond to instructions sent by either PJM or the Company as a result of either a change in demand or market prices.

Q. WILL THE COMPANY REPLACE WOODSDALE WITH AN ASSET THAT MAINTAINS OR IMPROVES THE RELIABILITY AND RESILIENCE OF THE ELECTRIC TRANSMISSION GRID? PLEASE EXPLAIN.

A. Yes. The replacement technology for Woodsdale is expected to, at a minimum, maintain the reliability and resilience of the electric transmission grid as required by KRS 278.264.

Q. WILL THE COMPANY REPLACE WOODSDALE WITH AN ASSET THAT MAINTAINS THE MINIMUM RESERVE CAPACITY REQUIREMENT ESTABLISHED BY THE UTILITY'S RELIABILITY COORDINATOR? PLEASE EXPLAIN.

A. Yes. The replacement generation for Woodsdale will provide the same amount of capacity towards meeting the minimum reserve capacity requirement established by PJM as the existing Woodsdale units.

Q. WILL THE COMPANY REPLACE WOODSDALE WITH AN ASSET THAT HAS THE SAME OR HIGHER CAPACITY VALUE AND NET CAPABILITY, UNLESS THE UTILITY CAN DEMONSTRATE THAT SUCH CAPACITY VALUE AND NET CAPABILITY IS NOT NECESSARY TO PROVIDE RELIABLE SERVICE.

A. Yes, the replacement generation for Woodsdale will provide the same or higher capacity value and net capability as necessary to provide reliable service.

Q. CAN YOU CONFIRM THAT THE COMPANY'S DECISION TO EVENTUALLY RETIRE WOODSDALE IS NOT THE RESULT OF ANY FINANCIAL INCENTIVES OR BENEFITS OFFERED BY ANY FEDERAL AGENCY?

A. Yes, the decision is not based on any incentive or benefit offered by any federal agency. The Company's decision to retire Woodsdale in 2040 is driven by the need to maintain a reliable and resilient electrical system to the benefit of Duke Energy Kentucky's customers. There are no financial incentives offered by any federal agency that are driving the Company's decision.

Q. WILL DUKE ENERGY KENTUCKY COMMENCE RETIREMENT OR DECOMMISSIONING OF WOODSDALE BEFORE THE REPLACEMENT GENERATING CAPACITY MEETING THE REQUIREMENTS OF KRS 278.264 IS FULLY CONSTRUCTED, PERMITTED, AND IN OPERATION?

A. No. Again, the Company is not seeking authorization to retire and replace Woodsdale in this case. The Company is simply asking to adjust the depreciation expense for Woodsdale to include terminal net salvage value based on a December 31, 2040, retirement date.

Q. PLEASE EXPLAIN THE FACTORS THAT ARE IMPACTING WOODSDALE'S REMAINING SERVICE LIFE.

A. The primary factors impacting Woodsdale's remaining service life are the cost and feasibility to maintain the reliability of the asset as the asset approaches the end of its useful life. As a plant ages, there comes a point in time when the equipment and systems become nearly impossible to service and maintain. Parts and materials become obsolete, and OEMs and other suppliers cease providing service and support. Even if these suppliers and OEMs are still available to provide their services, the cost to maintain reliable service will increase as the assets require more frequent maintenance as the asset continues to age.

IV. PLANNED OUTAGE O&M DEFERRAL REQUEST

Q. PLEASE SUMMARIZE THE COMPANY'S REQUEST TO RE-INSTITUTE ITS PLANNED OUTAGE O&M DEFERRAL.

A. As part of its Application in this proceeding, the Company is seeking to re-implement its previously authorized deferral for planned outage O&M expense of its generation fleet. The Commission first approved this process as part of the Company's 2017 electric base rate case.[4] The Company explained that because of the Company's size, and the fact that its load is served primarily by two generating

[4]*In the Matter of the Electronic Application of Duke Energy Kentucky, Inc., for (1) An Adjustment of Electric Rates; (2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; (3) Approval of New Tariffs; (4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and (5) All Other Required Approvals and Relief,* Case No. 2017-00321, (KY.P.S.C. at 19-20) (Apr. 13, 2018).

assets, including a single 600 MW coal unit, planned maintenance outages have a significant impact on the Company's financial stability and performance.

As part of its decision in Case No. 2022-00372, the Commission eliminated this deferral, finding that the anticipated expense was in line with base rate amounts.[5]

Q. PLEASE EXPLAIN WHY THE COMMISSION SHOULD RE-ESTABLISH THIS DEFERRAL MECHANISM.

A. The Company's forecasted test year budget for planned outage O&M expense for the Company's East Bend and Woodsdale generating stations have been adjusted to reflect a representative (*i.e.*, average) level of expense. Planned outage O&M expense has been normalized based upon four years of actual O&M expense and four years of projected O&M expenses. In the Company's last base rate case, the Commission eliminated the deferral stating that the anticipated costs were in line with base rate amounts. As demonstrated by the 8-year average, the expenses can vary significantly year-to-year causing volatility in the Company's earnings. This is particularly true given Duke Energy Kentucky's small size. The deferral is designed to, over time, approach $0 and prevent this cost volatility from having significant influence on the Company's earnings. As Company witness Danielle L. Weatherston states in her testimony, permitting the Company to defer for future recovery any incremental amount over or under what is established in base rates for

[5] *In the Matter of the Electronic Application of Duke Energy Kentucky, Inc., for (1) An Adjustment of 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, (KY.P.S.C. at 18) (Oct. 12, 2023).

these expenses will also ensure that customers are not overpaying and the Company is not under recovering for actual costs incurred in serving customers.

Q. IS RE-ESTABLISHING THIS MECHANISM REASONABLE?

A. Yes. East Bend, as an over 40-year-old coal unit that is subject to ever increasing environmental pressures on its operations, has maintenance intervals with significant variations in costs year-over-year. Additionally, Duke Energy Kentucky is relatively small and only has two fossil-fueled generating stations, causing variations to have a greater impact on the Company's earnings. Allowing the deferral process helps prevent volatile swings in the Company's earnings which impacts financial metrics such as the Funds from Operations (FFO) to debt ratio. As discussed by Company witness Thomas J. Heath, the Company's FFO to debt calculation is a key metric utilized by the credit rating agencies when determining the credit rating and rating outlooks of a company. Company witness Heath also discusses the importance of maintaining credit ratings to be able to access capital markets at a lower cost in order to execute major capital projects and support outage planning to maintain overall reliability for customers.

Q. PLEASE EXPLAIN THE VOLATILITY IN MAINTENANCE COSTS FOR THE COMPANY'S GENERATION FLEET YEAR-OVER-YEAR AND PROJECTED INTO THE FUTURE.

A. The Company's generation fleet, like all generating assets, require routine maintenance to maintain their safe, reliable and efficient operation. Periodically, generating assets require larger maintenance scopes to be executed due to the normal lifecycle wear of larger components or systems. These variations in scale of maintenance activities are normal and are driven by several factors including the operating profile of the equipment, online monitoring, offline condition inspections, fleet operating experience, and OEM recommendations. These periods of large scope activities drive significant year-over-year variations in maintenance costs for the Company. Therefore, the year-over-year costs will also vary significantly. Projecting forward, this cycle is expected to continue.

Q. HOW DOES HAVING THE DEFERRAL MECHANISM FOR PLANNED OUTAGE O&M EXPENSE HELP THE COMPANY AND CUSTOMERS?

A. The deferral mechanism helps the Company and customers by mitigating the volatility of earnings and providing financial stability. This financial stability helps customers as it allows the Company to maintain credit ratings such that it can access capital markets at lower costs which customers ultimately pay in rates. Company witness Heath discusses the impacts of credit ratings on the Company and customers in greater detail in his testimony. The deferral will also ensure that customers are not overpaying, and the Company is not under recovering for actual costs incurred in serving customers.

V. FILING REQUIREMENTS (FR) SPONSORED BY WITNESS

Q. PLEASE DESCRIBE THE INFORMATION YOU SPONSOR IN FR 16(7)(B).

A. FR 16(7)(b) consists of the most recent capital construction budget containing the forecasted construction expenditures for a minimum of three years. I provided the forecasted capital construction budget for the Plants contained in FR 16(7)(b) and for Mr. Carpenter's use for the forecasted financial data.

Q. PLEASE DESCRIBE THE INFORMATION YOU SPONSOR IN FR 16(7)(F).

A. FR 16(7)(f) includes the following information for major projects constituting five percent or more of the annual construction budget during the three-year capital expenditure forecast: the starting date and completion date for each project and construction cost per year. I provided this information for the Plants contained in FR 16(7)(f).

Q. PLEASE DESCRIBE THE INFORMATION YOU SPONSOR IN FR 16(7)(G).

A. FR 16(7)(g) includes the following information for projects constituting less than five percent of the annual construction budget during the three-year capital expenditure forecast: the starting date and completion date for each project and construction cost per year. I provided this information for the Plants contained in FR 16(7)(g).

VI. CONCLUSION

Q. IS THE INFORMATION ON PLANT CONSTRUCTION PROJECTS AND OUTAGES YOU PROVIDED TO OTHER WITNESSES ACCURATE, TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes.

Q. WAS THE INFORMATION YOU SPONSOR IN FR 16(7)(b), FR 16(7)(f) AND FR 16(7)(g), PREPARED BY YOU AT YOUR DIRECTION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

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. 2024-00354

DIRECT TESTIMONY OF

JAMES J. MCCLAY

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 2, 2024

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I. INTRODUCTION AND PURPOSE

Q. STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James J. McClay, III, and my business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as Managing Director of Natural Gas Trading for Progress Energy Carolinas a utility affiliate of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company).

Q. PLEASE DESCRIBE BRIEFLY YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor's Degree in Business Administration, majoring in Finance from St. Bonaventure University. I joined Progress Energy in 1998 as the Manager of Power Trading and held that position through early 2003. I became the Director of Power Trading and Portfolio Management for Progress Energy Ventures through February 2007. From March 2007 through late 2008, I was the Director of Power Trading for Arclight Energy Marketing. From March 2009 through the present, I've been employed in various managerial roles at Progress Energy and Duke Energy overseeing Natural Gas trading, origination, transportation, jurisdictional financial hedging programs, fuel oil, emissions, trading and procurement. Prior to my tenure with Duke Energy, I was employed for approximately 13 years in Capital Markets as a U.S. Government fixed income securities trader with various banks and brokers/dealers.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE PUBLIC SERVICE COMMISSION?

A. Yes, I testified before the Kentucky Public Service Commission (Commission) in Case No. 2021-00086 as well as in multiple fuel adjustment clause (FAC) proceedings.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS MANAGING DIRECTOR OF NATURAL GAS TRADING.

A. As Managing Director of Natural Gas Trading, I manage the organization responsible for the natural gas trading, optimization, and scheduling functions for the regulated gas-fired generation assets in the Carolinas (Duke Energy Carolinas and Duke Energy Progress), Duke Energy Florida, Duke Energy Indiana, and Duke Energy Kentucky (collectively, the Utilities), as well as the organization responsible for power trading for Duke Energy Indiana and Duke Energy Kentucky. Additionally, I oversee the execution of the Utilities' financial hedging programs, fuel oil procurement, and emissions trading.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to discuss and explain Duke Energy Kentucky's proposal to implement a comprehensive power hedging program and a proposed modification to calculate unrecoverable purchased power quantity due to benchmark review. Secondly, I support the Company's gas management proposal for flexibility to manage its natural gas fuel for its Woodsdale generating station by the ability to sell excess gas volumes through normal course of business, when not needed to minimize fuel market volatility for customers in the FAC. Finally, I discuss Duke Energy Kentucky's rationale for considering Capacity Performance Insurance.

II. OVERVIEW OF DUKE ENERGY KENTUCKY'S CURRENT GENERATING RESOURCES AND PARTICIPATION IN WHOLESALE CAPACITY MARKETS

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF HOW DUKE ENERGY KENTUCKY MEETS ITS KENTUCKY LOAD OBLIGATIONS.

A. As further explained by Company witness John D. Swez, Duke Energy Kentucky currently owns and operates approximately 1,076 net installed megawatts (MW) of summer generating capacity, provided by two assets. Base load requirements are met by the East Bend Unit 2 Generating Station (East Bend), an approximate 600-megawatt (MW) (net rating) coal-fired unit located along the Ohio River in Boone County, Kentucky. The Company's peaking requirements are met with the Woodsdale Generating Station (Woodsdale), a six-unit natural gas-fired combustion turbine (CT) with approximately 476 MW (net summer rating) located in Trenton, Ohio. Additionally, the Company has approximately 3.7 MWs (net firm summer capacity rating) of distribution system tied solar that are treated as being behind the meter generation from PJM's perspective.

III. PROPOSAL TO IMPLEMENT A COMPREHENSIVE POWER HEDGING PROGRAM AND MODIFY CALCULATION OF PURCHASE POWER QUANTITY SUBJECT TO BENCHMARK REVIEW

Q. HOW DOES DUKE ENERGY KENTUCKY MANAGE THE RISKS OF EXPOSURE TO POWER MARKET PRICES FOR ITS CUSTOMERS TODAY?

A. Duke Energy Kentucky manages these risks through its long-term strategy through the integrated resource planning (IRP) process. Previously, the Company also utilized a Commission-approved back-up power supply plan whereby the Company managed risks through the PJM daily energy market during forced outages and fixed forward contract purchases during scheduled outages. The purpose of the back-up supply plan was to mitigate the risk of price spikes during scheduled outages because the price for back-up power would be fixed by the hedges. The Company's hedging strategy provided the flexibility to optimize the actual outage schedules under changing power markets and unit availability conditions through purchasing fixed price financial hedges in the liquid energy markets. Duke Energy Kentucky would make its forward contract purchases a few months in advance of the scheduled outages to lock in the power prices. If prices appeared to be increasing, the plan provided the flexibility to make the forward contract purchases for long-term periods. If forward prices appeared flat or falling, the Company would postpone these purchases. The Company's plan also provided flexibility to modify executed forward contract positions if scheduled outage dates are modified, by utilizing the liquidity of the power markets to unwind existing contracts and purchase new contracts to match new scheduled outage dates.

The back-up supply plan was reviewed and approved periodically by the Commission. The Company last sought approval of its back-up supply plan in Case No. 2021-00086.[1] The Company had requested approval of its hedging strategy through May 31, 2024. By Order dated November 30, 2021, the Commission approved the Company's plan through May 31, 2022, *only*, and denied it for future delivery years.[2]

In the Commission's Order in Case No. 2022-00372 for Duke Energy Kentucky's 2022 electric rate case, the Company's proposal to hedge scheduled outages was approved. Accordingly, the Company is currently operating under that rate case order.

Q. DOES DUKE ENERGY KENTUCKY PROPOSE TO MAKE ANY CHANGES TO THE WAY IT MANAGES CUSTOMER EXPOSURE TO MARKET PRICES AS PART OF THIS CASE?

A. Yes. Duke Energy Kentucky is proposing to implement a more comprehensive hedging strategy introducing additional power hedging for forced outages and economic hedging when the PJM AEP-Dayton (AD) hub market power price is under the cost of production. Customers will benefit from economic hedging by locking in a fixed price power hedge and avoid the expected higher production cost and operational cost of running the unit.

[1] *In the Matter of Electronic Back-up Power Supply Plan of Duke Energy Kentucky, Inc*, Case No. 2021-00086, Order (Nov. 30, 2021).
[2] *Id.*

Q. WHAT HEDGING TOOLS DOES DUKE ENERGY KENTUCKY PLAN TO USE?

A. Duke Energy Kentucky has used, for many years, fixed-priced financial hedging instruments for scheduled outages. These are financial swap and future contract products listed on Intercontinental Exchange (ICE) or through bilateral over the counter (OTC) broker market. The Company plans to use the same tools for the proposed comprehensive hedging program. The ICE is a well-established electronic marketplace for trading energy-related products. Among other product types, ICE offers trading in bilateral contracts for energy at fixed forward prices. The contract terms (such as hours of the day covered, the index price, credit, and liquidated damages provisions) are clearly defined, to enable trading in standardized products.

Q. WHY IS DUKE ENERGY KENTUCKY PROPOSING THIS CHANGE?

A. Spot market power prices have been volatile since the Company joined PJM markets in 2012. Through the end of September 2024, the average on-peak daily PJM AD Hub Day Ahead LMP was $41.08/MWH. For the same period, average daily AD Hub Real Time LMP was $40.69/MWH. However, there was a wide range of prices. Day Ahead daily price settled between $15.98/MWH and $580.27/MWH while Real Time price went from as low as $13.38/MWH to as high as $1,115.55/MWH. There were 92 days where Day Ahead daily price exceeded $100/MWH and 87 days in the same period that daily Real Time peak power prices reached above $100/MWH. Moreover, we observed hourly AD Hub Day Ahead or Real Time LMP over $100/MWH in most months since January of 2012, with the highest LMP at $3,873.90/MWH and the lowest at negative $232.53/MWH.

To help mitigate the exposure to the daily market volatility, if the position warrants, the Company can enter fixed price forward power purchase contracts that are financially settled on a specific future date at PJM AD Day-Ahead or Real Time LMPs. Locking in price certainty for customers helps reduce customer exposure to FAC volatility. The applicable LMPs on the settlement date for these contracts may be higher or lower than the price the Company paid for the forward contract and the Company will either pay or be refunded the difference.

Q. PLEASE EXPLAIN WHY THE COMPANY SHOULD BE PERMITTED TO HEDGE FOR ECONOMIC ENERGY PURCHASES AND HOW IT WOULD BENEFIT CUSTOMERS TO DO SO.

A. Though East Bend station was designed to be a base load generator, and its variable generation cost is normally lower than PJM market power prices, the Company has observed periods where PJM market prices dropped below East Bend's dispatch cost and made the unit uneconomic. In such cases, it is more economical and beneficial for customers to purchase lower cost power from PJM instead of running East Bend. For example, the week of November 11, 2024, the average daily PJM AD Hub on-peak power price was trading around $35/MWh on Intercontinental Exchange (ICE), which is approximately $8/MWh lower than East Bend's $43/MWh dispatch cost. It is estimated that customers could have saved nearly $600,000 for that week by buying power from PJM instead of running East Bend. To lock in potential savings for customers, it is essential to use financial hedging instruments to fix the cost of anticipated purchased power if a decision were made not to must run East Bend. In addition to customer cost savings, hedging economic energy purchases may reduce periods of uneconomic must run dispatch, reducing wear and tear on East Bend and potentially reducing O&M expenses. When PJM's market price increases to above East Bend's dispatch cost, the Company will bring East Bend online to commit the unit and use it to generate economic power at a cost below market price.

Q. HOW DOES DUKE ENERGY KENTUCKY PROPOSE TO PASS CREDITS AND CHARGES FROM MANAGING ITS REPLACEMENT PURCHASED POWER AND FINANCIAL HEDGES THROUGH TO CUSTOMERS?

A. Under past Back-up Supply plans, the Company was allowed to recover costs of replacement power purchased from PJM and financial hedges for scheduled outages via its FAC. For forced outages/derates, cost of replacement power from PJM was also recovered via its FAC, but limited by, among other things, the fuel cost of the lost generation. The Company recovers the portion of replacement power costs not recovered in the FAC in base rates. As discussed in Mr. Swez's direct testimony, Duke Energy Kentucky is requesting to reestablish the deferral for forced outage replacement purchase power costs not recovered in the FAC. As customers have similar exposure to volatile daily market prices during periods of scheduled outages, forced generation outages, and economic market purchases, the Company believes it is in customers' best interest to manage price exposure in all these cases.

Therefore, Duke Energy Kentucky proposes to treat all financial hedge results, both gains and losses through the FAC. Forced outage power replacement costs from PJM would be recovered either through base rates or FAC subject to 807 KAR 5:056.

Q. PLEASE EXPLAIN HOW CUSTOMERS HAVE SIMILAR EXPOSURE TO VOLATILE ENERGY MARKET PRICES DURING FORCED GENERATION OUTAGES GIVEN THE LIMITATIONS IN THE KENTUCKY FUEL ADJUSTMENT CLAUSE REGULATION 807 KAR 5:056.

A. Forced plant outages are unpredictable and can expose customers to day-to-day power price volatility for multiple days at a time. The multi-day customer energy market price exposure is the same exposure existing in scheduled outages that is currently mitigated by approved forward power market hedging. Customers are disadvantaged by the inability to mitigate the daily market volatility through procurement of power hedges for forced outage periods longer than a day. The unknown nature of a forced outage and its associated market replacement costs, require a more proactive way of protecting customers exposure by approving the ability to hedge through the PJM power markets. During a forced outage, the Company has proprietary knowledge of the emergent outage and the approximate return to service. This information can be used to protect the customer and lock in power price hedges for all or a portion of the market exposure.

Q. WILL IMPLEMENTING THIS PLAN AS YOU DESCRIBE RESULT IN LOWER RATES FOR CUSTOMERS?

A. The results of any hedging activity may or may not result in net fuel cost savings. However, Duke Energy Kentucky believes having a balanced and more comprehensive fuel price risk management approach that results in greater fuel cost certainty and mitigates volatility is in the customer's best interest.

Q. WILL IMPLEMENTING THIS PLAN AS YOU DESCRIBE REDUCE PRICE VOLATILITY RISK TO CUSTOMERS? PLEASE EXPLAIN.

A. Purchasing power hedges, limiting daily price risk exposures, and providing fuel price certainty is an important part of managing fuel price volatility. Locking in prices mitigates risks associated with volatile energy market prices. This approach protects consumers from price volatility and helps reduce electricity costs particularly during high demand periods or unexpected outages.

Q. WHY IS THIS CHANGE REASONABLE, NECESSARY, AND IN CUSTOMERS' BEST INTERESTS?

A. A more comprehensive hedge plan is a proactive measure to mitigate exposure to volatile spot energy prices and increase price certainty for customers. The proposed hedging plan is essential for maintaining price stability, protecting customers from price volatility, and helping mitigate overall electricity costs.

Q. HAVE ENERGY MARKET FUNDEMENTALS BECOME MORE VOLATILE, MAKING A COMPREHENSIVE HEDGING PROGRAM INCREASINGLY IN CUSTOMER BEST INTEREST?

A. Yes. Duke Energy Kentucky does not speculate on market prices; however, the energy markets are fundamentally changing in the US and rest of the world. The power markets are dependent and driven by the underlying interrelated fuel markets. Fueled by rapid development of generative artificial intelligence (AI), US and global power demand has grown and is projected to continue growing significantly, evidenced by a lengthy list of data centers announced to come online in the next several years. Foreign demand for energy, such as liquified natural gas, and global conflicts can result in substantial or frequent changes in prices contributing to the volatility of energy prices in the US. These factors and others have caused spot and forward energy market volatility to increase, changing the future landscape for coal and gas supply price stability. Thus, it is difficult to accurately predict where power prices will be in future months. Commencing a comprehensive hedging program provides immediate benefits to customers given the number of risk factors that can impact prices and trends. Duke Energy Kentucky would anticipate using the same power financial hedging method and products currently employed to hedge scheduled outages, to also hedge forced outages and economic purchases. A more comprehensive hedge program is in customers' best interest.

Q. PLEASE EXPLAIN HOW DUKE ENERGY KENTUCKY CALCULATES THE BENCHMARK FOR CALCULATING UNRECOVERABLE PURCHASED POWER COSTS TODAY.

A. Duke Energy Kentucky bases its benchmark for determining the limitation on recoverable purchased power on its highest cost units, the Woodsdale combustion turbines, consistent with the Commission's FAC regulation, 807 KAR 5:056, and the Commission's Order in Case No. 2016-0005, where the Commission directed Duke Energy Kentucky to calculate its highest-cost unit for the Woodsdale units by using an average of the minimum and maximum load level of operation and the maximum monthly natural gas price.[3]

Q. DOES DUKE ENERGY KENTUCKY PROPOSE TO MAKE ANY CHANGE TO THE WAY UNRECOVERABLE PURCHASED POWER COST SUBJECT TO BENCHMARK REVIEW IS CALCULATED AS PART OF THIS CASE?

A. Yes. If the Commission approves the Company's plan to implement a more comprehensive hedging program, Duke Energy Kentucky proposes to reduce the unrecoverable purchase quantity as a result of purchased power cost exceeding the benchmark by the quantity of financial power hedges purchased for that hour. Presently, unrecoverable purchase quantity is calculated by subtracting real-time generation from real-time load, i.e., Purchase Quantity (MWh) = RT Load (MWh) - RT Generation (MWh). As the Company regularly purchases monthly, weekly and daily financial hedges for scheduled outages, deducting these financial hedged

[3] *In the Matter of an Examination of the Application of the Fuel Adjustment Clause of Duke Energy Kentucky, Inc. from May 1, 2015 through October 31, 2015,* Case No. 2016-00005, Order, pp. 11-12 (Jul. 7, 2016).

volumes from the Purchase Quantity, would reduce the overall benchmark exposure in any given hour, as the financial hedges represent virtual generation to protect customers from price spikes. For example, in an hour with 500MWs of load, if 300MWs is covered by fixed price hedges, only 200MWs of load is exposed to the market price. Therefore, it is reasonable to take hedges into account when calculating purchased quantity exposed to the PJM market. Hereby Purchased Quantity would be reduced further by the hedged quantity before calculating the unrecoverable amount. Consequently, the formula becomes Purchase Quantity (MWh) = RT Load (MWh) - RT Generation (MWh) – Financial Power Hedge quantity (MWh).

All other steps in calculating the unrecoverable amount shall remain unchanged.

IV. REQUEST FOR MORE FLEXIBILITY IN MANAGING PHYSICAL GAS PURCHASES FOR NATURAL GAS GENERATION

Q. HOW DOES DUKE ENERGY KENTUCKY PROCURE NATURAL GAS FOR ITS WOODSDALE COMBUSTION TURBINES (CT's)?

A. The Woodsdale facility has six (6) CTs with each capable of generating approximately 79MWs (net summer rating). Natural gas for the Woodsdale CT's is procured in the spot market rather than term market due to the unpredictable nature of higher heat rate CT unit dispatches. PJM notifies Duke Energy Kentucky's dispatch desk with a Woodsdale day-ahead or real-time award schedule, identifying the unit(s) and MW volume per hour for dispatch. Duke Energy Kentucky will use the dispatch award to calculate the total volume of natural gas and engage third party suppliers in the natural gas market for pricing reflecting the firm delivered price of gas to Woodsdale. The Duke Energy Kentucky gas trader will evaluate the market offers and purchase the lowest cost volumes for delivered firm natural gas to the Woodsdale plant. The estimated fuel purchase is subject to actual variation in generation because of real-time changes in PJM dispatch.

Q. HOW DOES DUKE ENERGY KENTUCKY MANAGE THE DIFFERENCE BETWEEN ACTUAL GAS BURN AND PROCURED NATURAL GAS?

A. In the real-time market, PJM gives Duke Energy Kentucky's dispatch desk instructions on how many MWs to generate electricity in 5-minute intervals, usually deviating from day-ahead schedules. Therefore, actual gas burn is almost always different from the originally procured quantity. If the Woodsdale units burn more gas in the real-time market than procured quantity based on day-ahead schedule, then the Duke Energy Kentucky gas trader would purchase additional intra-day gas to meet the estimated shortfall or utilize its Operational Balancing Account (OBA) contract and use gas from the pipeline and create a short imbalance at the plant. The short imbalance quantity would be returned in kind at a later date according to the pipelines ability to receive gas for payback. Conversely, if the Woodsdale units burn less gas than procured quantity on that day, Duke Energy Kentucky would use its OBA agreement, and the surplus would be stored on the gas pipeline creating a long imbalance position at for Woodsdale. This long imbalance may be reduced by subsequent dispatches at a later date. If the pipeline has issued an Operational Flow Order (OFO), the positive imbalance cannot be used until the pipeline cancels the OFO at a future date. The Company experienced many cases where it had to store the entire procured daily quantity of supply because PJM did not follow the day-ahead schedule and cancelled real-time generation requests. Although the Company is still paid by PJM day-ahead LMPs without generating any electricity, it is forced to manage the leftover gas by leaving it on the pipeline rather than selling it into the intra-day gas market. In cases where the pipeline balances accumulate over time and exceed the OBA limit, Duke Energy Kentucky may be forced to burn the gas, or risk having the gas confiscated by the pipeline, to comply with the pipelines operational request.

Q HOW DOES DUKE ENERGY KENTUCKY PROPOSE TO MANAGE SURPLUS GAS MORE EFFICIENTLY?

A. Duke Energy Kentucky is proposing to disposition surplus gas through commodity sales. As discussed above, the Company from time to time is unable to burn gas that has been purchased due to real-time dispatch decisions by PJM or emergent pipeline operational issues. The ability to sell unused gas in the market is vital to effective gas management. For example, Woodsdale operates as peaking resources, running at specific times based on PJM's economic and reliability requirements. There may be gaps of several days or weeks between unit dispatches, which can leave gas stranded on the pipeline. Furthermore, changes in PJM's run schedule can lead to unutilized gas remaining on the pipeline, creating a "long" imbalance that risks pipeline stability. Pipelines require shippers to manage both short and long imbalances so integrity of pipeline operations can be maintained fostering grid stability. Low gas prices, coal retirements and increased intermittent resources have increased pipeline usage and limited pipeline operational flexibility to manage real time changes in demand. During periods of OFO pipeline restrictions, shippers face penalties for not complying when gas imbalances exceed daily limits. For instance, in 2023 TETCO issued OFO's 92 days, in 2024 YTD this has increased to 105 OFO days. Penalties for violating OFO limits are three times the daily gas index cost. A 10,000dth OFO violation using $3.00 gas cost, could result in a $90,000 penalty. When a pipeline issues an OFO, which could be due to constrained operations such as working gas shortages or low pipeline pressure, unused gas on the pipeline is subject to OFO penalties. During OFO periods, accumulated long imbalances cannot be used for daily generation until the OFO is canceled. Several days in a row of imbalances results in a large accumulation on the pipeline.

For example, during the cold weather experienced in January and February 2014, TETCO gas pipeline limited the daily actual burn volume that could be specifically nominated and delivered that day. These limitations, called imbalance postings, significantly limited Duke Energy Kentucky's ability to ensure that the Woodsdale units were available to its customers for dispatch in the PJM energy market. During these extended periods of pipeline operational limitations, Duke Kentucky lost the ability to reduce its excess long gas position on the pipeline. Pursuant to the OBA, TETCO could have required Duke Energy Kentucky to remedy the long position by either requiring the Company to sell the gas or by confiscating its delivery. When these operational restrictions were in place, burning the gas would not reduce Duke Energy Kentucky's long position since it was required to continue procuring additional natural gas that at least matched the anticipated expected burn at the station. Therefore, the position would never be reduced by burning the natural gas, and, consequently, selling the natural gas was the only viable option to ensure unit availability and avoid confiscation of the Company's delivered natural gas.

On January 28, 2014, TETCO notified Duke Energy Kentucky that the positive imbalance could not be increased and would need to be addressed immediately upon removal of the restrictions and be reduced in an efficient manner. As a result, rather than have the natural gas confiscated by TETCO, Duke Energy Kentucky sold portions of the gas on various dates in January and February 2014. The net loss from these sales was $534,000.

The Commission recognized the risks and benefits of Duke Energy Kentucky's operations in PJM. The Company showed that its operations at Woodsdale in extremely cold conditions during the first quarter of 2014 provided a substantial benefit to its customers and contributed to the reliability of operations in the PJM footprint. The Commission stated that to deny recovery of the loss on the sale of the unburned natural gas would be inconsistent with the intent of the Company's Profit-Sharing Mechanism (PSM). In Case No. 2014-00078, the Commission ordered that:

1. Duke Energy Kentucky's proposed accounting treatment for the sale of natural gas not consumed for generation and sold at a loss of $534,000 during the first quarter of 2014 is approved.
2. Duke Energy Kentucky shall include the loss of $534,000 on the sale of gas during the first quarter of 2014 in the PSM for the period beginning March 1, 2015.

At the time, Duke Energy Kentucky proposed that accounting treatment be approved to apply future losses or gains incurred under similar circumstances through the PSM, the Commission did not approve the proposal, stating that gains and losses should be investigated on a case-by-case basis.

Given the increased pipeline usage and limited pipeline operational flexibility to manage real-time changes in demand discussed earlier in my testimony, coupled with the increased capacity factor of Woodsdale discussed in both the direct testimony of Mr. William Luke and Mr. Swez, Duke Energy Kentucky is requesting the ability to share the net revenues or costs of gas purchased but not burned off-set by the sale of the surplus gas through the PSM. While selling natural gas may incur a gain or a loss depending on the market price at the time of sale in intra-day market it is in customers best interest to allow the timely sale of unused natural gas to better manage pipeline imbalances, enhance natural gas management and reduce the risk of either incurring costly OFO penalties or having the Company's delivered natural gas confiscated.

Q. WHY IS THIS CHANGE REASONABLE, NECESSARY, AND IN CUSTOMERS' BEST INTERESTS?

A. Though demand for natural gas has increased tremendously in the past twenty years, gas pipeline capacity expansions have not kept pace, and it has led to locational gas supply constraints. Pipelines have more frequently resorted to OFOs to balance supply and demand, which created new restrictions on the Company's ability to manage surplus gas supply. As mentioned above, when the Company's imbalance with the pipeline exceeds the OBA limit, it may be forced to burn the excess gas, in uneconomic market conditions. Duke Energy Kentucky believes, it is in customers' best interest to have the option of selling surplus gas to the market to minimize the overall cost of fuel. The Company will only exercise this option when it is the most economic approach to protect customers' interest.

V. CAPACITY PERFORMANCE INSURANCE

Q. IS DUKE ENERGY KENTUCKY EVALUATING CAPACITY PERFORMANCE INSURANCE? PLEASE EXPLAIN.

A. Yes. The Company is evaluating capacity performance insurance in order to protect customers against the rising cost of a potential Capacity Performance (CP) event given the substantially higher auction clearing price of $269.92/MW-Day in the 2025/2026 PJM base residual auction (BRA) that occurred in July 2024.

Q. WHY CONSIDER CAPACITY PERFORMANCE INSURANCE NOW?

A. As discussed above, PJM capacity prices significantly increased in the most recent BRA and are expected to continue to rise. The stop loss, or the maximum that an entity can be charged for a CP penalty is tied to the auction clearing price. Therefore, the higher the auction clearing price, the higher stop loss, and thus the higher the potential CP penalty.

Q. IS DUKE ENERGY KENTUCKY SOLELY CONSIDERING CAPACITY INSURANCE BECAUSE OF THE COMPANY'S REQUEST TO MOVE FROM FRR TO RPM?

A. No. This request is unrelated to Duke Energy Kentucky's request to move from a Firm Resource Requirement (FRR) construct to a Reliability Pricing Model (RPM) construct. In fact, under FRR under very high auction prices, the Company is actually exposed to a greater physical penalty than a financial CP payment. Thus, it is in customers best interest for the Company to have the ability to consider the purchase of insurance regardless of whether it is in FRR or RPM.

Q. WHAT IS DUKE ENERGY KENTUCKY'S PROPOSAL FOR TREATMENT OF ANY CAPACITY PERFORMANCE INSURANCE PREMIUMS AND PROCEEDS?

A. Duke Energy Kentucky would propose that in the event it decides to enter into an CP insurance policy, CP insurance premium costs and proceeds be included in the PSM.

Q. WHY IS IT REASONABLE FOR THE CP INSURANCE PREMIUMS AND PROCEEDS TO BE INCLUDED IN THE PSM?

A. The Commission has approved CP non-performance charges and credits be included in the PSM. Since CP insurance is specifically designed to mitigate CP non-performance charges, it is appropriate to include any mitigation costs and benefits in the PSM with the CP non-performance charges being mitigated. In the event a CP non-performance charge was levied by PJM, the CP insurance payout would offset the charge, reducing the total amount to flow through PSM.

VI. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

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. 2024-00354

DIRECT TESTIMONY OF

SHARIF S. MITCHELL

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC

December 2, 2024

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PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Sharif S. Mitchell, and my business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS), as Manager Accounting II. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of South Carolina with a Bachelor of Science in Accounting and earned my Master's Degree in Business Administration and Management from Webster University. I have 19 years of professional experience in various accounting roles, including jobs with BlueCross BlueShield of South Carolina, Time Warner Cable, and Charter Communications. I began my employment at Duke Energy in 2016 and was named to my current position of Manager II of Plant Accounting and Reporting in June 2022.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS MANAGER ACCOUNTING II.

A. As Manager Accounting II, I have responsibility for accounting and reporting activities within Duke Energy's electric and natural gas utilities related to fixed assets, including electric plant in service, construction work in progress, and depreciation.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am responsible for actual net plant in service and construction work in progress contained in rate base and other actual plant-related items that Duke Energy Kentucky witness, Mr. Grady "Tripp" S. Carpenter uses in his testimony. I co-sponsor with Mr. Carpenter the following Schedules in satisfaction of Filing Requirements (FR) 16(8)(b): B-2, B-2.1, B-2.2, B-2.3, B-2.4, B-2.5, B-2.6, B-2.7, B-3, B-3.1, B-3.2, and B-4. I sponsor Schedule D-2.24 in satisfaction of FR 16(6)(b) and FR 16(8)(d), as well as the actual plant data on Schedule K page 1, and the composite depreciation rates on Schedule K, both being in response to FR 16(8)(k). The source and sponsor of the budgeted and projected data as shown on these schedules is Mr. Carpenter. The source and sponsor of the proposed depreciation and amortization accrual rates used in these schedules, including the supporting depreciation study, is Company witness Mr. John J. Spanos.

II. SCHEDULES SPONSORED BY WITNESS

Q. PLEASE DESCRIBE THE INFORMATION CONTAINED IN THE SECTION B SCHEDULES.

A. The Section B schedules develop the Jurisdictional Net Plant in Service. The schedules are based on the Company's budget records as of the end of the base period (February 28, 2025) and the end of the forecast period (June 30, 2026).

Q. PLEASE DESCRIBE SCHEDULE B-2.

A. Schedule B-2 shows the plant in service including allocated common plant by major property grouping for the base period and the 13-month average as of the plant valuation date of June 30, 2026. The amount shown in the column labeled "Adjusted Jurisdiction" on page 1 of 2, and "13-Month Average Adjusted Jurisdiction" on page 2 of 2, represents plant in service that is deemed used and useful in providing electric service to our Kentucky jurisdictional customers.

Q. PLEASE DESCRIBE SCHEDULE B-2.1.

A. Schedule B-2.1 consists of a further breakdown of Schedule B-2 by the Federal Energy Regulatory Commission (FERC) and Company Account for each major property grouping for the base period and the forecast period. The plant in service investment shown in the column labeled "Adjusted Jurisdiction" on pages 1 through 6, and "13-Month Average Adjusted Jurisdiction" on pages 7 through 12, represents electric plant in service including allocated common plant that is deemed used and useful in providing electric service to the Company's Kentucky jurisdictional customers.

Q. PLEASE DESCRIBE SCHEDULE B-2.2.

A. Schedule B-2.2 shows proposed adjustments to plant in service for the base period and the forecast period. The adjustments shown on this schedule are related to Asset Retirement Obligation (ARO) Balances, street lighting balances, deferred depreciation related to the purchase of the Dayton Power & Light (DP&L, now known as AES Ohio) share of East Bend, and environmental compliance assets. The adjustment for ARO is made to remove the ARO balances out of rate base for separate recovery. The lighting adjustments remove customer lighting balances that are recovered through separate tariffs from rate base. The adjustment for the deferred depreciation related to the acquisition of DP&L's share of East Bend is related to the regulatory asset approved in Case 2015-00120. This adjustment adds this regulatory asset to rate base consistent with treatment approved in the Company's last base rate cases (Case 2017-00321, 2019-00271 and 2022-00372). Each of these adjustments is shown as of the base period and is projected for the forecast period. Finally, the adjustment for the environmental compliance assets removes the assets approved by the Commission to include in the Environmental Compliance Plan and recover through the Environmental Surcharge Mechanism (Rider ESM).

Q. PLEASE DESCRIBE SCHEDULE B-2.3.

A. Schedule B-2.3 shows beginning and ending balances, as well as gross additions, retirements and transfers by FERC and Company Account for each major property grouping for the base period and the forecast period.

Q. PLEASE DESCRIBE SCHEDULE B-2.4.

A. Schedule B-2.4 is entitled "Property Merged or Acquired" for the base period and the forecast period. Duke Energy Kentucky projects that no property will be merged or acquired during the base period or forecast period, so no items appear in this schedule.

Q. PLEASE DESCRIBE SCHEDULE B-2.5.

A. Schedule B-2.5 is entitled "Leased Property" and provides data for the base period and the forecast period. The Company does not project to have any assets under capital leases as of the base period or forecast period.

Q. PLEASE DESCRIBE SCHEDULE B-2.6.

A. Schedule B-2.6 shows the property held for future use included in rate base for the base period and forecast period. The Company has not included any property held for future use in rate base.

Q. PLEASE DESCRIBE SCHEDULE B-2.7.

A. Schedule B-2.7 contains data on utility property excluded from rate base for the base period and forecast period. There are no exclusions of utility property from rate base.

Q. PLEASE DESCRIBE SCHEDULE B-3.

A. Schedule B-3 shows the total plant investment and Reserve for Accumulated Depreciation and Amortization by FERC and Company Account grouping for the base period and the forecast period. The amounts for the forecast period on pages 7 through 12 are 13-month averages. The adjusted jurisdictional reserve in the last column is applicable to the jurisdictional plant shown on Schedule B-2, "Adjusted Jurisdiction" and "13-Month Average Adjusted Jurisdiction."

Q. PLEASE DESCRIBE SCHEDULE B-3.1.

A. Schedule B-3.1 shows adjustments to Accumulated Depreciation and Amortization for the base period and the forecast period. The adjustments shown on this schedule are the related accumulated depreciation balances for the adjustments to Plant in Service shown on Schedule B-2.2, which are described above.

Q. PLEASE DESCRIBE SCHEDULE B-3.2.

A. Schedule B-3.2 lists the 13-month average jurisdictional plant investment and reserve balance as of June 30, 2026, for each FERC and Company Account within each major property grouping. It also shows the proposed depreciation and amortization accrual rate, calculated annual depreciation and amortization expense, percentage of net salvage value, average service life and curve form, as applicable for each account. The calculated annual depreciation and amortization was determined by multiplying the 13-month average adjusted jurisdictional plant investment for the forecast period by the proposed depreciation and amortization accrual rates.

With this filing, the Company filed with the Commission proposed depreciation and amortization accrual rates prepared in 2024 and sponsored by Mr. Spanos of Gannett Fleming, Inc., who prepared the depreciation study. The account numbers referred to in the depreciation study were those in effect in 2024 for Duke Energy Kentucky. The Company requests that the Commission approve these new depreciation and amortization accrual rates included in this filing and that the depreciation and amortization accrual rates be effective July 1, 2025, corresponding with the effective date of the electric rates established in this case.

The amortization of the regulatory asset related to deferred depreciation for the Acquisition of DP&L's share of East Bend is the annual amortization amount approved in Case No. 2017-00321.

Q. PLEASE DESCRIBE SCHEDULE B-4.

A. Schedule B-4 is a list of Construction Work in Progress (CWIP) by major property grouping. The Company is not requesting to include recovery of CWIP in base rates.

Q. PLEASE DESCRIBE SCHEDULE D-2.24.

A. Schedule D-2.24 reflects the adjustment to the forecasted period depreciation expense to reflect annualized depreciation expense as calculated on Schedule B-3.2. Schedule

B-3.2 shows annual depreciation on 13-month average plant balance on June 30, 2026, using the new proposed depreciation rates.

Q. PLEASE DESCRIBE THE INFORMATION YOU SPONSOR IN SCHEDULE K.

A. I sponsor the actual plant data submitted on page 1 of Schedule K. This information includes Plant in Service by major property grouping and Reserve for Accumulated Depreciation and Amortization by utility service for the 13-month average forecast period, for the base period and as of December 31 for each of the last ten years. Plant held for future use and construction work in progress have also been provided for the same periods. I also sponsor the composite depreciation rates shown on Schedule K.

Q. PLEASE DESCRIBE ANY AROS WITH POTENTIAL SETTLEMENT IN THE FUTURE.

A. Duke Energy Kentucky has AROs related to legal obligations for the following items: closure of the coal ash basin and the East and West landfills at East Bend, removal of company-owned telecommunications assets from towers, and removal of solar assets. Costs to close the coal ash basin and landfills at East Bend are ongoing and are being recovered or will be recovered through the Rider ESM. The removal of the company-owned telecommunications assets from leased towers is projected to begin in 2028, and removal of solar assets is projected to begin in 2047.

The telecommunications ARO is $1.6 million on August 31, 2024, and is supported by underlying cash flows of $1.5 million to remove telecommunication assets. The solar ARO is $0.5 million on August 31, 2024, and is supported by underlying cash flows of $1.2 million to remove solar assets.

III. INFORMATION PROVIDED TO OTHER WITNESSES

Q. DID YOU SUPPLY ANY INFORMATION TO OTHER WITNESSES FOR THEIR USE IN THIS PROCEEDING?

A. Yes, I provided Mr. Carpenter with the actual net book value for the existing gas, electric, general, and common plant for the period ending August 31, 2024, for his use in calculating the forecasted financial data.

IV. CONCLUSION

Q. WERE SCHEDULES B-2, B-2.1, B-2.2, B-2.3, B-2.4, B-2.5, B-2.6, B-2.7, B-3, B-3.1, B-3.2, B-4, AND D-2.24, THE INFORMATION YOU PROVIDED ON SCHEDULE K, AND THE INFORMATION YOU PROVIDED TO MR. CARPENTER, (EXCLUDING THE BUDGET AND FORECAST NUMBERS PREPARED BY MR. CARPENTER AND THE PROPOSED DEPRECIATION AND AMORTIZATION ACCRUAL RATES AND SUPPORTING DEPRECIATION STUDY PREPARED BY MR. SPANOS) PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Sharif S. Mitchell, Director of Accounting, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

Sharif S. Mitchell Affiant

Subscribed and sworn to before me by Sharif S. Mitchell on this 02nd day of December, 2024.

NOTARY PUBLIC

GABRIELLE RAMOS
NOTARY PUBLIC
MECKLENBURG COUNTY, NC
COMMISSION EXP. FEB. 16, 2028

My Commission Expires: 02/16/2028

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. 2024-00354

DIRECT TESTIMONY OF

JOSHUA C. NOWAK

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 2, 2024

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Joshua C. Nowak. I am employed by Concentric Energy Advisors, Inc. (Concentric) as a Vice President. Concentric is a management consulting and economic advisory firm, focused on the North American energy and water industries. Based in Marlborough, Massachusetts, and Washington, D.C., Concentric specializes in regulatory and litigation support, financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am submitting this testimony to the Kentucky Public Service Commission (the Commission) on behalf of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company).

Q. PLEASE DESCRIBE YOUR EXPERIENCE IN THE ENERGY AND UTILITY INDUSTRIES AND YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS.

A. I hold a Bachelor's degree in Economics from Boston College, and have more than 15 years of experience in providing economic, financial, and strategic advisory services. As a consultant, I primarily advise clients in regulated utility industries and have provided testimony regarding financial matters before multiple regulatory agencies. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. I have provided testimony before the Federal Energy Regulatory Commission (FERC) as well as state and provincial jurisdictions in the U.S. and Canada. Prior to joining Concentric in 2018, I was employed by National Grid USA where I was responsible for regulatory filings related to the cost of capital across the company's multiple U.S. operating companies and service territories. A summary of my professional and educational background is presented in Attachment JCN-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my direct testimony is to present evidence and provide a recommendation for the return on equity (ROE) for Duke Energy Kentucky. My direct testimony also discusses the Company's capital structure in comparison to the proxy group of companies supporting my analysis.

Q. ARE YOU SPONSORING ANY ATTACHMENTS IN THIS PROCEEDING?

A. Yes. My analyses and recommendations are supported by the data presented in Attachments JCN-2 through JCN-10, which have been prepared by me or under my direction. I sponsor the following attachments:

- JCN-2 – Comprehensive Summary of ROE Results
- JCN-3 – Proxy Group Screening Analysis
- JCN-4 – Constant Growth Discounted Cash Flow (DCF) Analysis

- JCN-5 – Market Risk Premium (MRP)
- JCN-6 – Capital Asset Pricing Model (CAPM) Analysis
- JCN-7 – Bond Yield Plus Risk Premium Analysis
- JCN-8 – Expected Earnings Analysis
- JCN-9 – Regulatory Framework Comparison
- JCN-10 – Capital Structure Analysis

II. SUMMARY OF TESTIMONY

Q. WHAT IS YOUR CONCLUSION REGARDING THE APPROPRIATE COST OF EQUITY AND CAPITAL STRUCTURE FOR DUKE ENERGY KENTUCKY?

A. I have estimated Duke Energy Kentucky's ROE based on the results of the DCF model, the CAPM, and the Bond Yield Plus Risk Premium (Risk Premium) model and the general economic and capital market environment and the influence such conditions exert over the results. In addition, to assess the reasonableness of the DCF, CAPM, and Risk Premium results and evaluate the available returns for alternative investments, I considered the Expected Earnings analysis. In addition, I analyzed the Company's business and regulatory risk profile that must be considered in determining where the Company's cost of equity falls within the range of analytical results. A summary of the results of my analyses are shown below in Figure 1.

Figure 1: Summary of Results

	Low Mean	Mean	High Mean
Primary Analyses			
DCF Result	10.23%	10.41%	10.62%
CAPM Result	11.39%	12.11%	12.82%
Risk Premium	10.41%	10.44%	10.46%
Average		**10.99%**	
Benchmark Analysis			
Expected Earnings		10.86%	

The DCF, CAPM, and Risk Premium analysis produce a range of estimates of the Company's cost of equity of 10.23 percent to 12.82 percent. Based on these analyses, I consider an ROE range of 10.25 percent to 11.25 percent to be reasonable. From within that range, and considering the Company's risk profile, I recommend an ROE of 10.85 percent which is slightly above the midpoint of the range of reasonableness. As to the capital structure, Duke Energy Kentucky's requested capital structure of 52.728 percent equity and 47.272 percent debt (42.483 percent long-term debt and 4.789 percent short-term debt) is reasonable relative to the range of capital structures for the operating companies held by the proxy group companies.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE ANALYSES THAT YOU CONDUCTED TO SUPPORT YOUR ROE RECOMMENDATION.

A. As mentioned, my ROE recommendation is based on the range of results produced from four modeling methodologies. Analysts and academics understand that ROE models are tools to be used in the ROE estimation process, and that strict adherence to any single approach, or the specific results of any single approach, can lead to flawed conclusions. No model can exactly pinpoint the correct cost of equity, but each is designed to provide a unique estimate of the return required to attract equity investment. Therefore, my analysis considers the range of results produced by these four different models. The DCF analysis estimates the cost of equity based on market data on dividend yields and analysts' projected earnings per share growth rates from reputable third-party sources. The CAPM analysis is based on both current and forecasted interest rates and a forward-looking market risk premium. The Risk Premium approach calculates the risk premium as the spread between authorized ROEs for vertically integrated electric utilities and Treasury bond yields. The Expected Earnings approach is based on projected returns on book equity that investors expect to receive over the next three to five years. My ROE recommendation is ultimately based on the range of results produced by these four methodologies.

My recommendation also considers the general economic and capital market environment and the influence capital market conditions exert over the results of the DCF, CAPM and Risk Premium models. In addition, I consider the Company's business and regulatory risks in relation to a set of proxy companies to assist in the determination of the appropriate ROE and capital structure from within the range of my analytical results.

Q. HOW IS THE REMAINDER OF YOUR DIRECT TESTIMONY ORGANIZED?

A. The remainder of my Direct Testimony is organized as follows:

- Section III provides background on the regulatory principles that guide the determination of ROE.
- Section IV presents a review of current and prospective economic and capital market conditions and the implications on the cost of capital for utilities.
- Section V describes the criteria and approach for the selection of a proxy group of comparable companies.
- Section VI provides a description of the data and methodologies used to estimate the cost of equity, as well as the results of the various ROE estimation models and concludes with my recommendation and an assessment of its reasonableness under the *Hope* test.
- Section VII discusses Duke Energy Kentucky's regulatory risks, relative to the proxy group.
- Section VIII reviews Duke Energy Kentucky's capital structure in the context of the proxy group.
- Finally, Section IX summarizes my results, conclusions, and recommendation.

III. REGULATORY PRINCIPLES

Q. PLEASE DESCRIBE THE GUIDING PRINCIPLES USED IN ESTABLISHING THE COST OF CAPITAL FOR A REGULATED UTILITY.

A. The foundations of public utility regulation require that utilities receive a fair rate of return sufficient to attract needed capital to maintain important infrastructure for customers at reasonable rates. The basic tenets of this regulatory doctrine originate from several bellwether decisions by the United States Supreme Court, notably *Bluefield Waterworks and Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) (*Bluefield*), and *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944) (*Hope*). In *Bluefield*, the Court stated:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties…
>
> The return should be reasonably sufficient to assure investor confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

Later, in *Hope*, the Court established a standard for the ROE that remains the guiding principle for ratemaking in regulatory proceedings to this day:

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of

> the enterprise, so as to maintain its credit and to attract capital.

Q. PLEASE EXPLAIN HOW THESE PRINCIPLES APPLY IN THE CONTEXT OF THE REGULATED RATE OF RETURN.

A. Regulated utilities rely primarily on common stock and long-term debt to finance permanent property, plant, and equipment. The allowed rate of return for a regulated utility is based on its weighted average cost of capital, where the costs of the individual sources of capital (i.e., debt and equity) are weighted by their respective book values. The ROE represents the cost of raising and retaining equity capital and is estimated by using one or more analytical techniques that use market data to quantify investor requirements for equity returns. However, the ROE cannot be derived through quantitative metrics and models alone. To properly estimate the ROE, the financial, regulatory, and economic context must also be considered.

The DCF, CAPM, Risk Premium, and Expected Earnings approaches, while fundamental to the ROE determination, are still only models. The results of these models cannot be mechanistically applied without also using informed judgment to consider economic and capital market conditions and the relative risk of Duke Energy Kentucky compared to the proxy group companies.

Based on these widely recognized standards, the Commission's order in this case should provide Duke Energy Kentucky with the opportunity to earn a return on equity that is:

- Adequate to allow the Company to attract the capital that is necessary to provide safe and reliable service (the "capital attraction standard");

- Sufficient to ensure the Company's ability to maintain its financial integrity (the "financial integrity standard"); and
- At a level that is comparable to returns required on investments of similar risk (the "comparability standard").

Importantly, a fair return must satisfy all three of these standards. The allowed ROE should enable the Company to finance capital expenditures on reasonable terms and provide it with the ability to raise capital under a full range of capital market circumstances to serve its customers.

Q. IS DUKE ENERGY KENTUCKY'S ABILITY TO ATTRACT EQUITY CAPITAL AFFECTED BY ROES THAT ARE AUTHORIZED FOR OTHER UTILITIES?

A. Yes, it is. Duke Energy Kentucky competes with other investments of similar risk for equity capital from the market. In addition, Duke Energy Kentucky competes with other investments within Duke Energy Corporation for equity capital from its parent company. Therefore, the ROE awarded to a utility sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk. A company's cost of equity is defined by, and equal to, the opportunity cost of investing in that company. In other words, if higher returns are available from other investments of comparable risk, investors have an incentive to direct their capital to those investments. This means that an authorized ROE for Duke Energy Kentucky that is below ROEs authorized for other utilities could inhibit its ability to attract capital on reasonable terms for investments to be made on behalf of customers in Kentucky.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING REGULATORY PRINCIPLES?

A. The ratemaking process is premised on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, the utility must have the opportunity to recover invested capital and the market-required return on that capital. Because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital on favorable terms. The financial community carefully monitors the current and expected financial condition of utility companies as well as the regulatory environment in which they operate. In that respect, the regulatory environment is one of the most important factors considered by both debt and equity investors in their assessments of risk. It is therefore essential that the ROE authorized in this proceeding take into consideration the current and expected capital market conditions that Duke Energy Kentucky faces, as well as investors' expectations and requirements regarding both risks and returns. A reasonable ROE is required both for continued capital investment by the Company and to maintain confidence in Kentucky's regulatory environment among credit rating agencies and investors.

IV. ECONOMIC AND CAPITAL MARKET CONDITIONS

Q. WHY IS IT IMPORTANT TO CONSIDER THE EFFECTS OF CURRENT AND EXPECTED ECONOMIC AND FINANCIAL MARKET CONDITIONS WHEN SETTING THE APPROPRIATE ROE?

A. It is important to consider current and expected conditions in the general economy and financial markets because the authorized ROE for a public utility should allow the utility to attract investor capital at a reasonable cost under current and foreseeable economic and financial conditions as underscored by the *Hope* and *Bluefield* decisions discussed previously. The standard ROE estimation tools, such as the DCF, CAPM, Risk Premium, and Expected Earnings models, each reflect the state of the general economy and financial markets by incorporating specific economic and financial data. These inputs are, however, only samples of the various economic and market forces that determine a utility's required return. Consideration must also be given to whether the assumptions relied on in the current or projected market data are appropriate. If investors do not expect current market conditions to continue in the future, it is possible that the ROE estimation models will not provide an accurate estimate of investors' forward-looking required return. Therefore, an assessment of current and projected market conditions is integral to any ROE recommendation.

Q. WHAT ARE THE KEY FACTORS AFFECTING THE COST OF EQUITY FOR REGULATED UTILITIES IN THE CURRENT AND PROSPECTIVE CAPITAL MARKETS?

A. The cost of equity for regulated utility companies is being affected by several key factors in the current and prospective capital markets including the uncertainty regarding the economy, the impacts of the Federal Reserve's approach to interest rates and inflation, concerns over the ongoing elevated interest rates, and the heightened uncertainty and volatility in equity markets and resulting utility performance, which has lagged the broader market. Collectively, these factors contribute to heightened market risk and an increase in investor-required returns, relative to capital markets circumstances in place during the Company's last rate case. In this section, I discuss these factors and how they affect the models used to estimate the cost of equity for regulated utilities.

A. Monetary Policy

Q. HOW DO THE NATION'S MONETARY POLICY ACTIONS IMPACT CAPITAL MARKETS AND THE U.S. ECONOMY?

A. The Federal Reserve is responsible for "conducting the nation's monetary policy by influencing money and credit conditions in the economy in pursuit of full employment and stable prices."[1] The Federal Reserve implements monetary policy through raising or lowering interest rates which impacts the demand for goods and services. This, in turn, impacts employment and inflation. Monetary policy has shifted dramatically over the past several years in response first to COVID-19, and then to record high inflation. The capital markets are significantly affected by the Federal Reserve's policy. While the primary monetary policy tool used by the Federal Reserve is the short-term interest rate for overnight interbank loans, it has

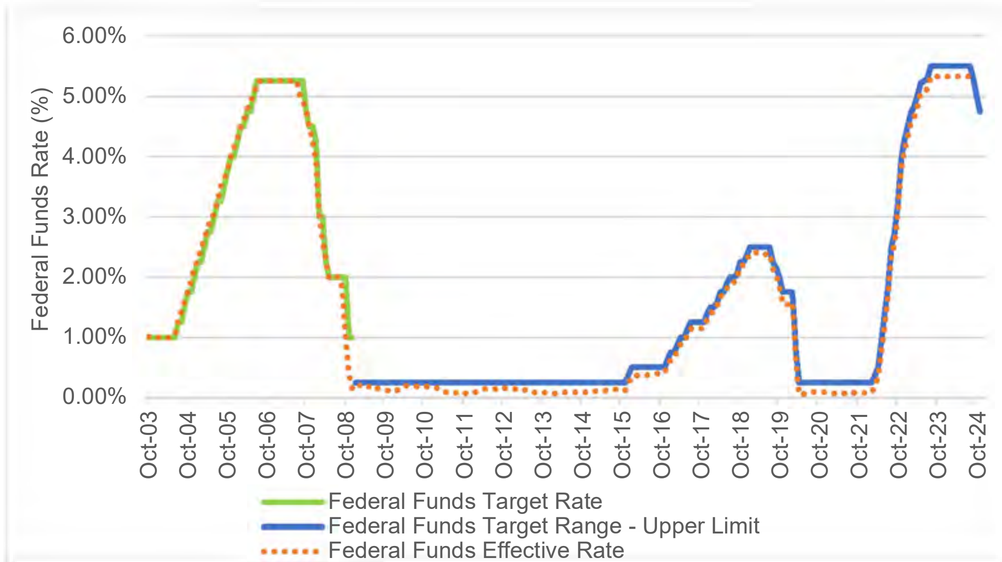
[1] Federal Reserve, "The Fed - What is the purpose of the Federal Reserve System?" available at https://www.federalreserve.gov/faqs/about_12594.htm.

far-reaching consequences for capital markets and significantly influences long-term interest rates and the cost of equity. As discussed in more detail below, current Federal Reserve policy continues to be focused on inflationary concerns, but it is important to note, even if inflation moderates, the current monetary policy stance is likely to have a long-lasting effect on capital market conditions.

Q. WHAT STEPS DID THE FEDERAL RESERVE TAKE TO STABILIZE FINANCIAL MARKETS AND SUPPORT THE ECONOMY IN RESPONSE TO COVID-19?

A. Beginning in 2022, inflation surged to levels not seen since the late-1970s and early-1980s, and the Federal Reserve had little choice but to aggressively battle inflation through raising interest rates. Previously, in response to the economic effects of COVID-19, the Federal Reserve decreased the federal funds rate in March 2020 to a target range of 0.00 percent to 0.25 percent (which remained in effect until March 2022) in addition to other stimulus measures that increased the supply of money in the economy. The Federal Reserve began unwinding its quantitative easing program in 2022 and has thus far increased the target rate 11 times to a target rate of 5.25 percent to 5.50 percent through August 2024 (the highest level in the last 20 years). As shown in Figure 2 below, the Federal Reserve only began reducing the federal funds rate, first by 50 basis points in September and then by 25 basis points in November to a target rate of 4.50 percent to 4.75 percent.

Figure 2: FOMC Federal Funds Rates



Despite the recent rate reduction, the Federal Reserve indicated that inflation remains a key consideration for the Committee:

> Recent indicators suggest that economic activity has continued to expand at a solid pace. Since earlier in the year, labor market conditions have generally eased, and the unemployment rate has moved up but remains low. Inflation has made progress toward the Committee's 2 percent objective but remains somewhat elevated.
>
> The Committee seeks to achieve maximum employment and inflation at the rate of 2 percent over the longer run. The Committee judges that the risks to achieving its employment and inflation goals are roughly in balance. The economic outlook is uncertain, and the Committee is attentive to the risks to both sides of its dual mandate.
>
> In support of its goals, the Committee decided to lower the target range for the federal funds rate by 1/4 percentage point to 4-1/2 to 4-3/4 percent. In considering additional adjustments to the target range for the federal funds rate, the Committee will carefully assess incoming data, the evolving outlook, and the balance of risks. The Committee will continue reducing its holdings of Treasury securities and agency debt and agency mortgage-backed securities. The Committee is strongly committed to supporting maximum

> employment and returning inflation to its 2 percent objective.
>
> In assessing the appropriate stance of monetary policy, the Committee will continue to monitor the implications of incoming information for the economic outlook. The Committee would be prepared to adjust the stance of monetary policy as appropriate if risks emerge that could impede the attainment of the Committee's goals. The Committee's assessments will take into account a wide range of information, including readings on labor market conditions, inflation pressures and inflation expectations, and financial and international developments.[2]

Although year-over-year inflation rates have eased over the last several months—increasing just 2.40 percent from September 2023 to September 2024, down from the high of 9.10 percent in June 2022 as measured by the Consumer Price Index (CPI)—the Federal Reserve also affirmed that inflation "remains somewhat elevated."[3]

Q. HOW HAVE CAPITAL MARKETS RESPONDED?

A. In response to monetary policy, high inflation, and disappointing earnings reports, capital markets over the past several years have been volatile, and the stock market has lost substantial value. While the S&P 500 closed at record highs on the first trading day of 2022, by mid-June of that year, the S&P 500 was down more than 21 percent, at that time wiping out all of 2021's gains.

And although the S&P 500 has steadily gained ground since that time, the utility sector has fared far worse. From June 2022, at the peak of inflation, through

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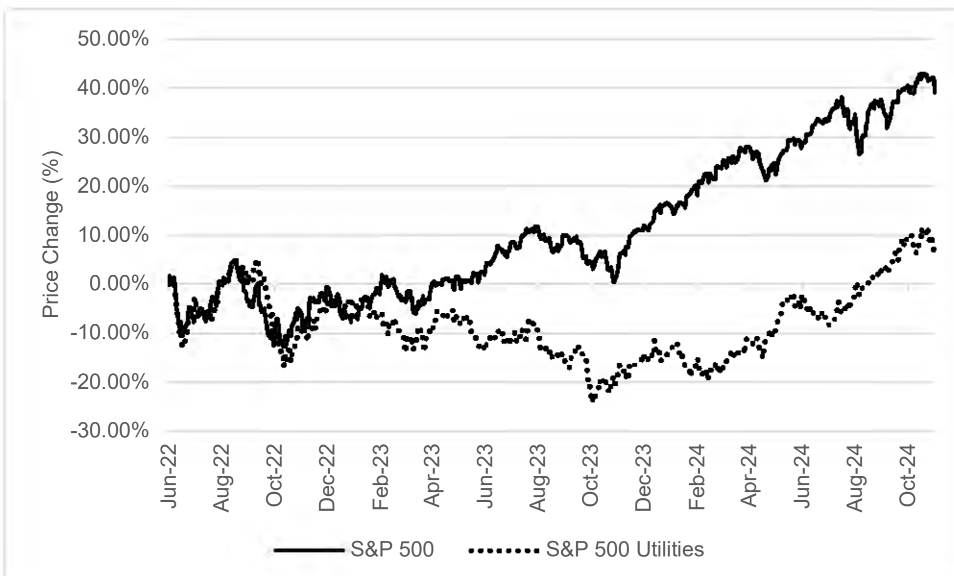
[2] FOMC Press Release (November 7, 2024). Available here: https://www.federalreserve.gov/monetarypolicy/files/monetary20241107a1.pdf.

[3] FOMC Press Release (November 7, 2024). Available here: https://www.federalreserve.gov/monetarypolicy/files/monetary20241107a1.pdf; Bureau of Labor Statistics, https://www.bls.gov/charts/consumer-price-index/consumer-price-index-by-category-line-chart.htm.

October 2024, the S&P 500 Index increased nearly 40 percent, but the S&P Utilities Index increased by less than 10 percent on a price change basis, as shown in Figure 3. Since Duke Energy Kentucky filed its last case in December 2022, the S&P Utilities Index has lagged the S&P 500 Index by more than 25.00 percent. This suggests a more difficult environment for raising capital for utilities as compared to the broader market, which indicates upward pressure in the cost of equity capital for utilities. That is, a lower performing stock price indicates investors require a higher relative return for an equity investment.

Figure 3: S&P 500 and S&P 500 Utilities Indices Performance (6/1/2022 to 10/31/2024)



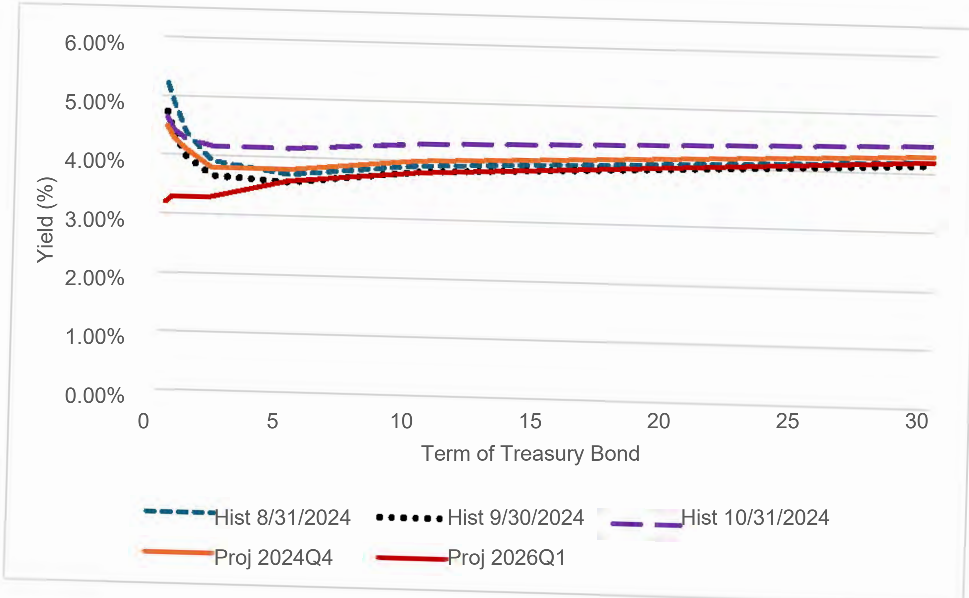
Q. WAS THE FEDERAL RESERVE'S RECENT RATE CUT CONSISTENT WITH INVESTORS' EXPECTATIONS?

A. Yes, investors generally expected the Federal Reserve to reduce interest rates in September and November 2024. For example, according to CME Group's FedWatch Tool, as of September 17, 2024 (the day before the Federal Reserve announced a 50-basis-point interest rate cut), there was a 64-percent probability that the target rate would be cut 50 basis points to 4.75-5.00 percent (and another 36-percent probability that the cut would be 25 basis points to 5.00-5.25 percent). On November 6, 2024 (the day before the Federal Reserve announced a 25-basis-point interest rate cut) there was a 98 percent probability that the target rate would be cut 25 basis points to 4.50-4.75 percent. As such, the effect of the decrease in near-term interest rates have had little effect on investors' long-term expectations. However, uncertainty over the economy and potential for a recession continue to prevail.

Q. WHAT ARE EXPECTATIONS FOR LONG-TERM INTEREST RATES?

A. Despite the 75-basis-point reduction on the federal funds rate in recent months, long-term interest rates are not expected to change much in the coming years. That is, the change in the federal funds rate is primarily having an effect on short-term interest rates. As shown in Figure 4 below, the yield curve is currently inverted with short-term interest rates higher than long-term interest rates. However, this is not expected to persist beyond 2025 as investors expect short-term rates to continue to decline, while long-term rates remain at current levels. Figure 4 below includes the yield as of August 31, 2024, September 30, 2024, and October 31, 2024, for 3-month, 6-month, 1-year, 2-year, 5-year, 10-year, and 30-year treasury securities. In addition, projections from Blue Chip Financial Forecasts demonstrate that the expectation for continued reductions in the federal funds rate will cause near-term yields to decline over the next year while long-term rates are expected to remain near current levels.

Figure 4: Current and Projected Interest Rates



Q. PLEASE EXPLAIN WHY THESE ELEVATED INTEREST RATES ARE IMPORTANT TO THE ROE ANALYSIS.

A. In general, as interest rates on government bonds increase, the cost of capital also must increase, as utilities—competing with interest rates on government bonds—must offer higher dividend yields to attract and retain investors. As dividend yields increase, however, the stock price declines (and, therefore, the cost of equity increases). The reason for this is that the stock price inherently reflects a company's future cash flows, thus, future dividends are factored into the share price. After an ex-dividend date (i.e., the date on which a dividend is paid), the share price often declines to reflect the dividend paid (i.e., distributing a proportion of profits to shareholders). As interest rates remain elevated, utilities must continue to pay high dividends to keep investors, which suggests that the stock price of these companies would decline (and the cost of equity increase) in response to interest rates. To reflect this correlation in ROE models, all else equal, higher dividend yields produce higher ROE estimates in DCF models. Interest rates also are a direct input to both the CAPM and the Risk Premium models.

Q. HAVE YOU FACTORED THESE CIRCUMSTANCES INTO YOUR UPDATED COST OF EQUITY ESTIMATES FOR DUKE ENERGY KENTUCKY, AND, IF SO, WHAT CONCLUSIONS DO YOU DRAW?

A. Yes. I have relied on the most recent market data and forecasts available to me in my analysis and ROE recommendations. Long-term interest rates have increased substantially since the historical lows of 2020 and are expected to remain elevated as the Federal Reserve continues to focus on inflation and employment. As interest rates increase, the cost of capital generally increases. Interest rates are direct inputs to the CAPM and risk premium analyses and indirectly affect the DCF models, as increasing interest rates influence increases in dividend yields (and decreases in utility stock prices, which suggest an increase in the cost of equity).

Q. WHAT IS YOUR CONCLUSION REGARDING HOW MARKET CONDITIONS AFFECT THE COST OF EQUITY FOR UTILITIES SUCH AS DUKE ENERGY KENTUCKY?

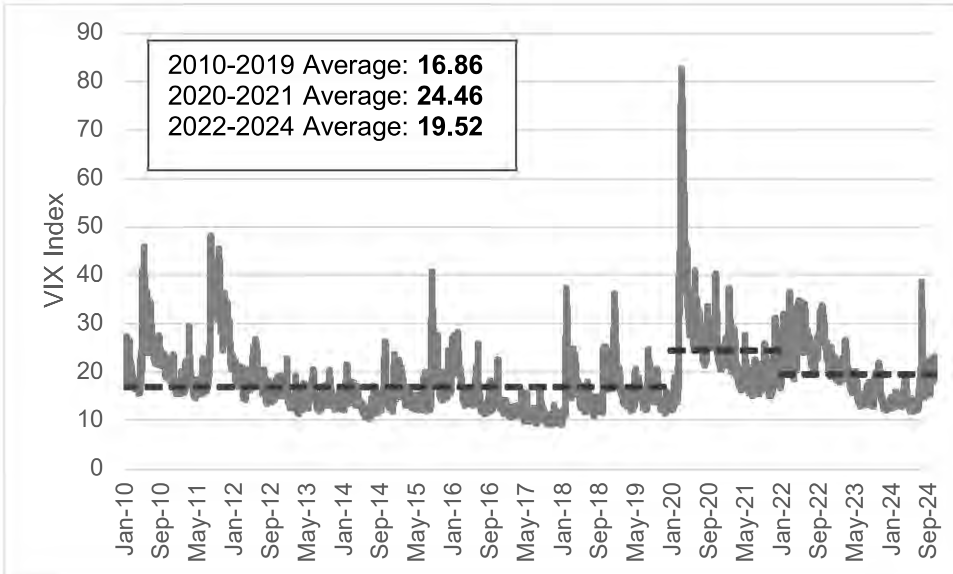
A. While consensus expectations are for long-term inflation to continue to moderate and near-term interest rates to decline, long-term interest rates are expected to remain at an elevated level, relative to rates seen in recent years. As such, there is no indication that the cost of equity for utility companies will decline as inflation moderates and near-term interest rates decline.

B. Ongoing Uncertainty and Volatility in Capital Markets

Q. TO WHAT EXTENT ARE CONDITIONS EXPECTED TO STABILIZE IN THE NEAR TERM?

A. The economy remains in a tenuous phase of the business cycle with concerns over a potential recession, persistent inflation, and persistently high interest rates. As such, capital market conditions continue to be unstable as interest rates remain elevated. The Chicago Board Options Exchange (CBOE) Volatility Index (VIX) has remained above long-term historical levels, indicating stock investors remain anxious about the economy and company earnings. The VIX, a measure of expected price fluctuations in the S&P 500, reached 82.7 on March 16, 2020, in response to the pandemic. As a point of comparison, the VIX last traded above 80 in November 2008 during the financial crisis and Great Recession of 2008/09. The VIX has continued to reach levels above 25.0 in 2023 and 2024. As shown in Figure 5, the average level in 2022-2024 has been 19.52 through October 31, 2024, compared to the average of 16.86 from 2010-2019. This indicates that equity market volatility levels have partially settled but continue to remain above the historical mean. Importantly, the VIX reached a recent peak in August 2024 of 38.57, demonstrating the tenuous position of equity markets as the Federal Reserve considers further interest rate reductions. Both the pace and magnitude of future Federal Reserve policy decisions could have substantial effects on equity markets.

Figure 5: CBOE VIX – January 1, 2010 – October 31, 2024[4]



Q. HOW HAS THE CURRENT ECONOMIC ENVIRONMENT AFFECTED THE CREDIT RATINGS FOR UTILITIES?

A. Consistent with the underperformance of the utility industry relative to the broader equity market demonstrating higher relative risk for utilities, credit ratings have also declined across the utility industry. According to a recent report by S&P Global Ratings (S&P) on utilities, "credit quality weakened again in 2021 and represented the second consecutive year that downgrades outpaced upgrades" primarily due to weak financial measures and ESG-related risks.[5] Fitch Ratings (Fitch) points to capital spending, elevated interest rates, and high fuel prices creating cost pressures leading to a "deteriorating" outlook on the utilities sector.[6] While the views of rating agencies represent an important consideration, they are not the only factor

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[4] Source: Bloomberg Professional.

[5] S&P Global Ratings, *For the First Time Ever, The Median Investor-Owned Utility Ratings Falls to the 'BBB' Category*, January 20, 2022.

[6] S&P Global Market Intelligence, "Fitch sees various cost pressures behind 'deteriorating' US utilities outlook," November 14, 2022.

that equity investors consider. The important distinction is that credit rating agencies are primarily focused on the ability of a utility to pay its debts, while equity analysts and institutional investors are more concerned with profitability and value creation.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE EFFECTS OF THE CURRENT MARKET ENVIRONMENT ON THE COST OF EQUITY FOR DUKE ENERGY KENTUCKY?

A. The current capital market conditions continue to be heavily influenced by monetary policy aimed at mitigating inflationary pressures. This has caused both short-term and long-term interest rates to remain high. As a practical matter, investors consider a range of opportunities, which includes bonds. With the sustained elevated interest rates, utilities are less attractive absent a corresponding increase in returns. With the Federal Reserve's expectation for elevated interest rates for an extended period of time, this will continue to put upward pressure on the cost of capital for utilities. Therefore, it is important that these factors are accounted for in the cost of equity models.

C. Conclusions

Q. WHAT CONCLUSIONS DO YOU DRAW FROM YOUR ANALYSIS OF CAPITAL MARKET CONDITIONS?

A. Investors continue to face interest rate pressures and uncertainty, as the Federal Reserve continues its response to broad economic concerns. Long-term interest rates remain substantially higher than the historical lows of 2020 and are expected to remain elevated looking forward. Importantly, this requires the use of both current and forecast bond yields in the CAPM and Risk Premium models. Fluctuations in utility valuations impact the results of the DCF model. The dividend yield is calculated using historical average stock prices, which may not fully reflect forward market expectations. These circumstances collectively reinforce the importance of using multiple models, as I have with the CAPM, DCF, Risk Premium, and Expected Earnings approaches.

V. PROXY GROUP SELECTION

Q. WHY IS IT NECESSARY TO SELECT A PROXY GROUP TO ESTIMATE THE COST OF EQUITY FOR DUKE ENERGY KENTUCKY?

A. Since the ROE is a market-based concept and Duke Energy Kentucky is not publicly traded, it is necessary to establish a group of companies that is both publicly traded and comparable to Duke Energy Kentucky. Even if Duke Energy Kentucky were a publicly traded entity, it is possible that transitory events could bias the Company's market value in one way or another in a given period. A significant benefit of using a proxy group is the ability to mitigate the effects of short-term events that may be associated with any one company. The proxy companies used in my ROE analyses possess a set of business and operating characteristics similar to the Company's vertically integrated electric utility operations, and thus provide a reasonable basis for estimating the Company's ROE.

Q. PLEASE PROVIDE A SUMMARY PROFILE OF DUKE ENERGY KENTUCKY.

A. Duke Energy Kentucky provides electric generation, transmission, and distribution service to approximately 155,000 residential, commercial, and industrial customers in Boone, Campbell, Grant, Kenton, and Pendleton counties Kentucky. It owns approximately 1,076 MW of net-installed capacity (summer rating) regulated generation assets, including coal, natural gas, and approximately 3.7 MW of firm summer capacity solar generation facilities. The Company has long-term issuer ratings from S&P of BBB+ (Outlook: Stable), and Moody's Investors Service (Moody's) of Baa1 (Outlook: Stable).[7]

Q. PLEASE DESCRIBE THE SPECIFIC SCREENING CRITERIA YOU HAVE UTILIZED TO SELECT A PROXY GROUP.

A. I began with the 36 investor-owned domestic electric utilities covered by Value Line and then screened companies according to the following criteria:

1. Consistently pays quarterly cash dividends;
2. Maintains an investment grade long-term issuer rating (BBB- or higher) from S&P;
3. Is covered by more than one equity analyst;
4. Has positive earnings growth rates published by at least two of the following sources: Value Line, First Call (as reported by Yahoo! Finance), and Zacks Investment Research (Zacks);
5. Owns regulated electric generation assets;
6. Regulated net operating income makes up more than 80 percent of the consolidated company's net operating income (based on a 3-year average from 2021-2023);

[7] S&P Capital IQ Pro.

7. Regulated net operating income from regulated electric operations makes up more than 80 percent of the consolidated company's regulated net operating income (based on a 3-year average from 2021-2023); and
8. Is not involved in a merger or other transformative transaction.

Q. DID YOU INCLUDE DUKE ENERGY CORPORATION IN YOUR ANALYSIS?

A. No, I did not. To avoid the circular logic that would otherwise occur, it is my practice to exclude the subject company, or its parent holding company, from the proxy group.

Q. WHAT IS THE COMPOSITION OF YOUR RESULTING PROXY GROUP?

A. Based on the screening criteria discussed above, and financial information through fiscal year 2023, I arrived at a proxy group consisting of the 15 companies shown in Figure 6. The results of my screening process are shown in Attachment JCN-3.

Figure 6: Proxy Group

Company	**Ticker**
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Entergy Corporation	ETR
Evergy, Inc.	EVRG
IDACORP, Inc.	IDA
NextEra Energy	NEE
NorthWestern Corporation	NWE
OGE Energy Corporation	OGE
Pinnacle West Capital Corporation	PNW
Portland General Electric Company	POR
PPL Corporation	PPL
Southern Company	SO
TXNM Energy, Inc.	TXNM
Xcel Energy Inc.	XEL

Q. DOES YOUR SCREENING CRITERIA RESULT IN A GROUP OF COMPANIES THAT INVESTORS WOULD VIEW AS COMPARABLE TO DUKE ENERGY KENTUCKY?

A. Yes. While no proxy group will be identical in risk as the Company, I believe this group of electric utilities is reasonably comparable to the financial and operational characteristics of Duke Energy Kentucky. The proxy group screening criterion requiring an investment grade credit rating ensures that the proxy group companies, like Duke Energy Kentucky, are in sound financial condition. Because credit ratings take into account business and financial risks, the ratings provide a broad measure of investment risk for investors. I have only included companies in the proxy group that own regulated generation assets because vertically integrated electric utilities have unique operating characteristics and business risks that cause investors to require a higher return on equity to compensate for those risks. These unique risks are not shared by pure transmission and distribution electric utilities. Additionally, I have screened on the percent of net operating income from regulated operations to differentiate between utilities that are protected by regulation and those with substantial unregulated operations or market-related risks. Also, I have screened on the percentage contribution of the electric utility segment to regulated consolidated financial results to select companies that, since this proceeding is limited to determining the appropriate ROE for the stand-alone electric operations of Duke Energy Kentucky. These screens collectively reflect key risk factors that investors consider in making investments in electric utilities. The results of each screening criterion on each potential proxy company are presented in Attachment JCN-3.

Q. WHAT IS YOUR CONCLUSION WITH REGARD TO THE PROXY GROUP FOR DUKE ENERGY KENTUCKY?

A. I conclude that my group of 15 vertically integrated electric utilities adequately reflects the broad set of risks that investors consider when investing in a U.S. regulated vertically integrated electric utility such as Duke Energy Kentucky.

VI. DETERMINATION OF THE APPROPRIATE COST OF EQUITY

Q. WHAT MODELS DID YOU USE IN YOUR ROE ANALYSES?

A. I have considered the results of several ROE estimation models, including the Constant Growth DCF model, the CAPM, the Bond Yield Plus Risk Premium approach, and an Expected Earnings analysis. When faced with the task of estimating the cost of equity, analysts are inclined to gather and evaluate as much relevant data (both quantitative and qualitative) as can be reasonably obtained.

A. Constant Growth DCF Model

Q. PLEASE DESCRIBE THE DCF APPROACH.

A. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows, which for purposes of the model, are assumed to be equal to all expected future dividends. Thus, the return required by investors is implied by the per share price of a company's common stock. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + ... + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

Where P_0 represents the current stock price, $D_1 \ldots D_\infty$ are all expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation, which can be simplified and rearranged, to the Constant Growth form of the DCF model, expressed as the sum of the expected dividend yield and long-term growth rate:

$$k = \frac{D(1+g)}{P_0} + g \qquad [2]$$

Where "k" equals the required return, "D" is the current dividend, "g" is the expected growth rate, and "P_0" represents the current stock price. Stated in this manner, the cost of common equity is equal to the expected dividend yield plus the dividend growth rate.

Q. WHAT ARE THE ASSUMPTIONS UNDERLYING THE CONSTANT GROWTH DCF MODEL?

A. The Constant Growth DCF model is based on the following assumptions: (1) a constant average growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate greater than the expected growth rate.

Q. PLEASE SUMMARIZE YOUR APPLICATION OF THE CONSTANT GROWTH DCF MODEL.

A. I calculated DCF results for each of the proxy group companies using the following inputs:

- Average stock prices for the historical period, over 30, 90, and 180 trading days through October 31, 2024;
- Annualized dividend per share as of October 31, 2024; and
- Company-specific earnings growth forecasts for the term *g*.

My application of the Constant Growth DCF model is provided in Attachment JCN-4.

Q. WHY DID YOU USE AVERAGING PERIODS OF 30, 90, AND 180 TRADING DAYS?

A. It is important to use an average of recent trading days to calculate the term *P* in the DCF model to ensure that the calculated ROE is not skewed by anomalous events that may affect stock prices on any given trading day. At the same time, it is important to reflect the conditions that have defined the financial markets over the recent past. In my view, consideration of those three averaging periods reasonably balances these interests.

Q. DID YOU ADJUST THE DIVIDEND YIELD TO ACCOUNT FOR PERIODIC GROWTH IN DIVIDENDS?

A. Yes, I did. Utility companies tend to increase their quarterly dividends at different times throughout the year, so it is reasonable to assume that such increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for the purposes of calculating this component of the DCF model. This adjustment ensures that the expected dividend yield is representative of the coming 12-month period. Accordingly, the DCF estimates reflect one-half of the expected growth in the dividend yield.[8]

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[8] The expected dividend yield is calculated as $d_1 = d_0 (1 + ½ g)$.

Q. WHAT SOURCES OF GROWTH HAVE YOU USED IN YOUR DCF ANALYSIS?

A. I have used the consensus analyst five-year growth estimates in earnings per share (EPS) from First Call and Zacks, as well as EPS growth rate estimates published by Value Line.

Q. WHY DID YOU FOCUS ON EPS GROWTH?

A. The Constant Growth DCF model assumes that dividends grow at a constant rate in perpetuity. Accordingly, in order to reduce the long-term growth rate to a single measure, one must assume a constant payout ratio, and that earnings per share, dividends per share, and book value per share all grow at the same constant rate. Over the long term, however, dividend growth can only be sustained by earnings growth. As noted by Brigham and Houston in their text, *Fundamentals of Financial Management*: "Growth in dividends occurs primarily as a result of growth in *earnings per share* (EPS)."[9] It is therefore important to focus on measures of long-term earnings growth from credible sources as an appropriate measure of long-term growth in the DCF model.

Q. ARE OTHER SOURCES OF DIVIDEND GROWTH AVAILABLE TO INVESTORS?

A. Yes, although that does not mean that investors incorporate such estimates into their investment decisions. Academic studies suggest that investors base their investment

[9] Eugene F. Brigham and Joel F. Houston, Fundamentals of Financial Management (Concise Fourth Edition, Thomson South-Western), at 317 (emphasis added).

decisions on analysts' expectations of growth in earnings.[10] I am not aware of any similar findings regarding non-earnings-based growth estimates. In addition, the only forward-looking growth rates that are available on a consensus basis are analysts' EPS growth rates. The fact that earnings growth projections are the only widely accepted estimates of growth provides further support that earnings growth is the most meaningful measure of growth among the investment community.

Q. WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF ANALYSIS?

A. The results of my Constant Growth DCF analysis are provided in Attachment JCN-4 and summarized in Figure 7.

Figure 7: Constant Growth DCF Results

	Mean Low	Mean	Mean High
30-day average	9.10%	10.23%	11.01%
90-day average	9.26%	10.39%	11.18%
180-day average	9.49%	10.62%	11.41%

Q. HOW DID YOU CALCULATE THE MEAN HIGH, MEAN LOW, AND OVERALL MEAN DCF RESULTS?

A. I calculated the Mean High DCF result using the maximum growth rate (i.e., the maximum of the First Call, Value Line, and Zacks EPS growth rates) in

[10] *See*, e.g., Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts Growth Forecasts*, Financial Management, Summer 1992, at 65; and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management, Spring 1988, at 81. Please note that while the original study was published in 1988, it was updated in 2004 under the direction of Dr. Vander Weide. The results of that updated study are consistent with Vander Weide and Carleton's original conclusions.

combination with the expected dividend yield for each of the proxy group companies. I used a similar method to calculate the Mean Low DCF results, using the minimum growth rate for each company. The Mean results reflect the average growth rate from each source for each company in combination with the expected dividend yield.

B. CAPM Analysis

Q. PLEASE BRIEFLY DESCRIBE THE GENERAL FORM OF THE CAPITAL ASSET PRICING MODEL.

A. The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium (to compensate investors for the non-diversifiable or "systematic" risk of that security).[11] As shown in Equation [3], the CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \qquad [3]$$

Where:

K_e = the required ROE for a given security;

r_f = the risk-free rate of return;

β = the Beta of an individual security; and

r_m = the required return for the market as a whole.

[11] Systematic risks are fundamental market risks that reflect aggregate economic measures and therefore cannot be mitigated through diversification. Unsystematic risks reflect company-specific risks that can be mitigated and ultimately eliminated through investments in a portfolio of companies and/or market sectors.

The term ($r_m - r_f$) represents the Market Risk Premium (MRP). According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by Beta, which is defined as:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)} \quad [4]$$

Where:

r_e = the rate of return for the individual security or portfolio.

The variance of the market return, noted in Equation [4], is a measure of the uncertainty of the general market, and the covariance between the return on a specific security and the market reflects the extent to which the return on that security will respond to a given change in the market return. Thus, Beta represents the risk that the selected security will not be effective in diversifying systematic market risks.

Q. HAVE ECONOMIC AND FINANCIAL MARKET CONDITIONS ALSO AFFECTED THE CAPM?

A. Yes. As the Federal Reserve reduces federal funds rate, it is important to consider both current and projected bond yields. Using the 5-year forecast of bond yields helps alleviate short-term market factors affecting the risk-free rate, or "r_f" in the CAPM formula. As discussed in Section IV, interest rates continue to remain elevated. It is also important to recognize that Duke Energy Kentucky is financing long-lived assets, and the cost of capital should be forward looking to reflect that perspective.

Q. WHAT RISK-FREE RATE DID YOU USE IN YOUR CAPM ANALYSIS?

A. I considered three estimates of the expected risk-free rate: (1) the current 30-day average yield on 30-year U.S. Treasury bonds (i.e., 4.30 percent);[12] (2) the projected 30-year U.S. Treasury bond yield for Q1 2025 through Q1 2026 (i.e., 4.20 percent);[13] and (3) the projected 30-year U.S. Treasury bond yield for 2026 through 2030 (i.e., 4.30 percent).[14]

Q. WHAT MEASURES OF BETA DID YOU USE IN YOUR CAPM ANALYSIS?

A. As shown in Attachment JCN-6, I utilized two measures of Beta for the proxy group companies: (1) the reported Beta coefficients from Bloomberg (which are calculated using ten years of weekly data against the S&P 500 Index); and (2) the reported Beta coefficients from Value Line (which are calculated using five years of weekly data against the New York Stock Exchange Composite Index).

Q. WHAT MARKET RISK PREMIUM DID YOU USE IN YOUR CAPM ANALYSIS?

A. Consistent with the approach adopted by FERC, I used the Constant Growth DCF model to estimate the market capitalization-weighted total market return for the S&P 500 Index, using projected earnings growth rates and dividend yields. As shown in Attachment JCN-5, to calculate the Constant Growth DCF estimate for each company in the S&P 500, I relied on dividend yields as of October 31, 2024, as reported by Bloomberg Professional, and projected EPS growth rates from Value

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[12] Bloomberg Professional, as of October 31, 2024.
[13] Blue Chip Financial Forecasts, Vol. 43, No. 11, November 1, 2024, at 2.
[14] Blue Chip Financial Forecasts, Vol. 43, No. 6, June 1, 2024, at 14.

Line. In my initial analysis, I included all companies in the S&P 500. When investors purchase the S&P 500 Index or a mutual fund or exchange traded fund that mirrors the S&P Index, their total return is based on the returns for all 500 companies in the S&P Index. As such, this methodology provides the best indication as to the expected return for the overall market using the S&P 500 as a proxy. Applying this methodology suggests an expected market return of 15.07 percent. However, I applied FERC's more conservative convention to consider only a subset of S&P 500 companies with growth rates that are between 0 percent and 20 percent. This methodology suggests an expected market return of 11.41 percent.

Q. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSES?

A. The results of my CAPM analysis are provided in Attachment JCN-6 and summarized in Figure 8.

Figure 8: Proxy Group Average CAPM Results[15]

	CAPM Result
Value Line Beta Coefficients	
Current Risk-Free Rate	12.82%
2025-26 Projected Risk-Free Rate	12.82%
2026-30 Projected Risk-Free Rate	12.82%
Bloomberg Beta Coefficients	
Current Risk-Free Rate	11.41%
2025-26 Projected Risk-Free Rate	11.39%
2026-30 Projected Risk-Free Rate	11.41%

[15] Applying FERC's more conservative convention to consider only a subset of S&P 500 companies with growth rates that are between 0 percent and 20 percent.

C. Risk Premium Analysis

Q. PLEASE DESCRIBE THE RISK PREMIUM APPROACH THAT YOU USED.

A. In general terms, this approach recognizes that equity is riskier than debt because equity investors bear the residual risk associated with ownership. Equity investors, therefore, require a greater return (i.e., a premium) than would a bondholder. The Risk Premium approach estimates the cost of equity as the sum of the Equity Risk Premium and the yield on a particular class of bonds.

$$\text{ROE} = RP + Y \qquad [5]$$

Where:

RP = Risk Premium (difference between allowed ROE and the 30-Year Treasury Yield); and
Y = Applicable bond yield.

Since the equity risk premium is not directly observable, it is typically estimated using a variety of approaches, some of which incorporate *ex-ante*, or forward-looking, estimates of the cost of equity and others that consider historical, or *ex-post*, estimates. For my Risk Premium analysis, I have relied on authorized returns from a large sample of vertically integrated electric utility companies.

Q. WHAT DID YOUR RISK PREMIUM ANALYSIS REVEAL?

A. To estimate the relationship between risk premia and interest rates, I conducted a regression analysis using the following equation:

$$RP = a + (b \times Y) \qquad [6]$$

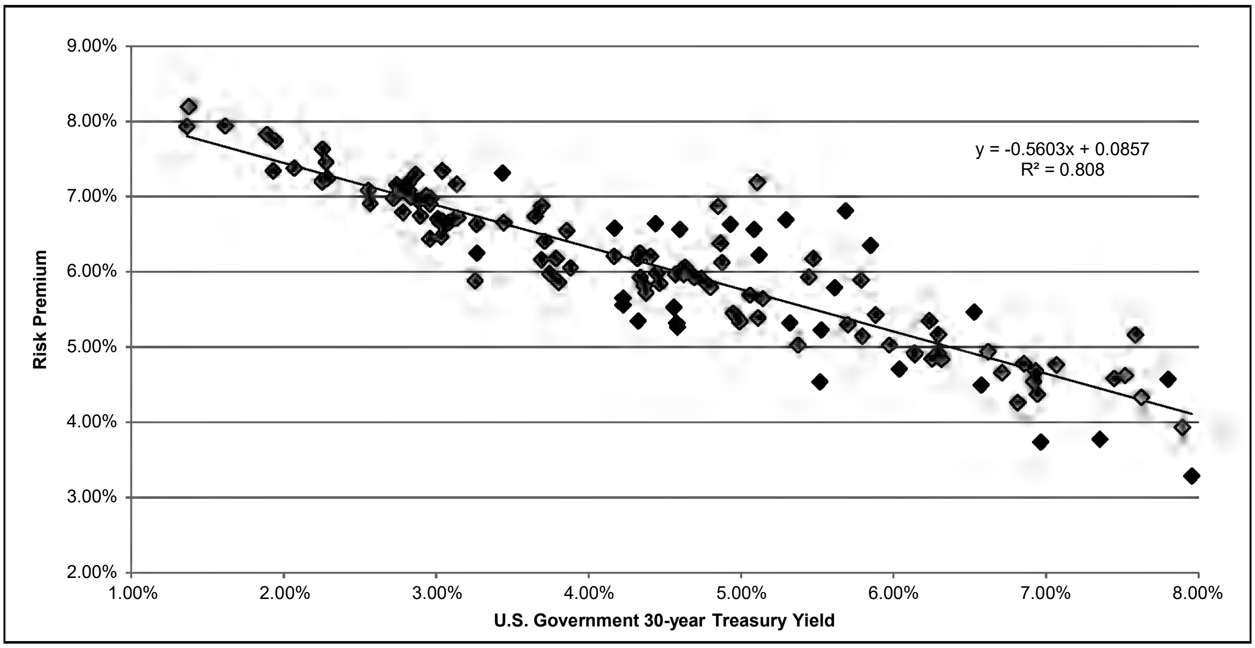
where:

RP = Risk Premium (difference between allowed ROEs and the 30-Year Treasury Yield);
a = Intercept term;

b = Slope term; and
Y = 30-Year Treasury Yield.

Data regarding allowed ROEs were derived from vertically integrated electric utility company rate cases from January 1, 1992, through October 31, 2024, as reported by Regulatory Research Associates.

Figure 9: Risk Premium Results



As illustrated by Figure 9 (above), the risk premium varies with the level of bond yield, and generally increases as the bond yields decrease, and vice versa. In order to apply this relationship to current and expected bond yields, I consider three estimates of the 30-year Treasury yield, including the current 30-day average, a near-term Blue Chip consensus forecast for Q1 2025 – Q1 2026, and a Blue Chip consensus forecast for 2026–2030. I find the projected five-year result to be most applicable for the following reasons: (1) investors are expecting increases in government bond yields; (2) investors typically have a multi-year view of their required returns on equity; and (3) Duke Energy Kentucky's robust capital expenditure plan requires that the Company continue to be able to attract capital on reasonable terms and conditions. Based on the regression coefficients in Attachment JCN-7, which allow for the estimation of the risk premium at varying bond yields, the results of my Risk Premium analysis are shown in Figure 10 below.

Figure 10: Risk Premium Results Using 30-Year Treasury Yield

	30-Day Average Yield on 30-Year Treasury Bond	Q1 2025–Q1 2026 Forecast for Yield on 30-Year Treasury Bond[16]	2026-2030 Forecast for Yield 30-Year Treasury Bond[17]
Yield	4.30%	4.20%	4.30%
Risk Premium	6.16%	6.21%	6.16%
Resulting ROE	10.46%	10.41%	10.46%

D. Expected Earning Analysis

Q. HAVE YOU CONDUCTED ANY OTHER ANALYSIS TO ESTIMATE THE COST OF EQUITY FOR DUKE ENERGY KENTUCKY?

A. Yes. I have also conducted an Expected Earnings analysis to estimate the cost of equity for Duke Energy Kentucky based on the projected ROEs for the proxy group companies.

Q. WHAT IS AN EXPECTED EARNINGS ANALYSIS?

A. The Expected Earnings methodology is a comparable earnings analysis that calculates the earnings that an investor expects to receive on the book value of a stock. The Expected Earnings analysis is a forward-looking estimate of investors'

[16] Blue Chip Financial Forecasts, Vol. 43, No. 10, October 1, 2024, at 2.
[17] Blue Chip Financial Forecasts, Vol. 43, No. 6, June 1, 2024, at 14.

expected returns. The use of an Expected Earnings approach based on the proxy companies provides a range of the expected returns on a group of risk-comparable companies to the subject company. This range is useful in helping to determine the opportunity cost of investing in the subject company, which is relevant in determining a company's ROE.

The Expected Earnings approach relying on expected returns for like-risk companies is a core strength of the model and consistent with the basic tenets of *Hope*: "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks." Since the Expected Earnings model provides an accounting-based approach that relies on investment analysts' projections of earnings on book equity, it affords the benefit of analyst insights, knowledge, and expertise in interpreting a given company's earnings prospects in the context of current market conditions.

Q. HOW IS THE EXPECTED EARNINGS APPROACH CALCULATED?

A. I relied on the projected ROE for the proxy companies as reported by Value Line for the period from 2027-2029. I then adjusted those projected ROEs to account for the fact that the ROEs reported by Value Line are calculated on the basis of common shares outstanding at the end of the period, as opposed to average shares outstanding over the entire period. As shown in Figure 11 below and Attachment JCN-8, the Expected Earnings analysis results in a mean of 10.86 percent and a median of 10.27 percent.

Figure 11: Expected Earnings Results

	ROE
Proxy Group Average	10.86%
Proxy Group Median	10.27%

Q. WHAT IS YOUR CONCLUSION REGARDING THE RESULTS OF THE EXPECTED EARNINGS MODEL?

A. The model captures investor expectations for ROEs for each company in the proxy group as estimated by impartial analysts. This is a valuable tool given the nature of the analysis here is designed to measure required returns for Duke Energy Kentucky. It is reasonable to assume that investors would require returns from investment in Duke Energy Kentucky similar to those they could earn in comparable investments, so these results are informative.

E. <u>Evaluating Model Results</u>

Q. PLEASE EXPLAIN HOW YOU CONSIDERED THE RESULTS OF THE DCF, CAPM, RISK PREMIUM, AND EXPECTED EARNINGS ANALYSIS TO ARRIVE AT YOUR ROE RECOMMENDATION.

A. As shown in Figure 12, I have considered the results of the DCF, CAPM, Risk Premium, and Expected Earnings analyses. For the DCF result, I included the average of the 30-day, 90-day, and 180-day analyses. For the CAPM result, I relied on the average of current and projected Treasury yields, the average of Value Line and Bloomberg Betas coefficients, and the MRP derived from a subset of the S&P 500 companies. For the Risk Premium analysis, I relied on the average of current and projected Treasury yields.

Figure 12: Base ROE Results

	Average	Median
Primary Analyses		
DCF Result	10.41%	10.32%
CAPM Result	12.11%	11.96%
Risk Premium	10.44%	10.44%
Average	**10.99%**	**10.94%**
Benchmark Analyses		
Expected Earnings	10.86%	10.27%

As discussed in the next Section of my testimony, these estimates serve as a base prior to consideration of the relative business and financial risks of Duke Energy Kentucky as compared to the proxy companies.

F. Consideration of Specific Risk Factors

Q. DOES YOUR RECOMMENDATION INCLUDE A DOWNWARD OR UPWARD ADJUSTMENT FOR DUKE ENERGY KENTUCKY SPECIFIC RISK FACTORS?

A. No, it does not. All the proxy group vertically integrated electric utilities face a challenging environment requiring continuous access to capital in order to meet public expectations of safe, reliable, and reasonably economic utility service. Duke Energy Kentucky's capital spending program will require the Company to maintain continuous access to capital markets on reasonable terms and conditions. For these reasons, it is important that the authorized ROE be set at a level that allows Duke

Energy Kentucky to continue to attract both debt and equity under favorable terms under a variety of economic and financial market conditions, including the inflationary conditions we are facing today and in the foreseeable future. My recommendation, however, makes no adjustment, explicit or implicit, for the specific capital expenditure requirements, generation risks, or regulatory mechanisms of Duke Energy Kentucky. As noted above, I excluded Duke Energy Corporation (and therefore Duke Energy Kentucky) from the proxy group I used to avoid any question of circularity of my results.

Q. HOW DOES THE COMPANY'S GENERATION PORTFOLIO AFFECT ITS RISK PROFILE?

A. The coal-fired East Bend Generating Station (East Bend) is a substantial component of Duke Energy Kentucky's generation fleet. Both S&P and Moody's have pointed to the Company's reliance on coal generation as a credit risk as compared to other vertically integrated utilities as it relates to a carbon transition risk profile. S&P identifies exposure to coal generation a key risk for Duke Energy Kentucky.[18] Specifically, S&P notes:

> Environmental factors are a negative consideration in our credit rating analysis of [Duke Energy Kentucky]. The company is more exposed compared to peers given its heavy reliance on coal-fired generation. Approximately 51.5% of the company's total electric generation fleet capacity of roughly 1,164 MW is coal-based, which exposes it to the potential for changing environmental regulations that might require significant capital investments.[19]

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[18] S&P Global Ratings, *Duke Energy Kentucky Inc.*, May 21, 2024, at 1.
[19] S&P Global Ratings, "Duke Energy Kentucky Inc.," May 21, 2024, at 6.

Moody's similarly finds that the Company has a higher environmental risk profile, observing that Duke Energy Kentucky's environmental issuer profile score "reflects a highly negative exposure to carbon transition risk because coal is the utility's primary generation fuel."[20] In addition, several coal-fired generation assets have already been retired and more is planned to be retired over the coming decade. The Company's base case scenario in its most recent integrated resource plan calls for East Bend to be retired by December 31, 2038, which is consistent with these industry trends. Further, the Company is recommending that the depreciation schedule for East Bend should be adjusted to 2038 to more closely align with its anticipated life, although the Company is not requesting a specific retirement plan in this proceeding. This is consistent with industry trends and a necessary step toward mitigating the incremental risk presented by the Company's significant reliance on coal-fired generation.

Q. IS THERE ANY BASIS TO TREAT DUKE ENERGY KENTUCKY AS LESS RISKY THAN ITS PEER UTILITIES?

A. No, there is not. I have undertaken a review of regulatory mechanisms designed to mitigate certain business risks, and they support treating the results from the proxy group I selected as representative of the business risk of a prudently managed vertically integrated regulated electric utility like Duke Energy Kentucky. The results of my analysis are presented in Attachment JCN-9. Specifically, I examined the following factors that affect the regulatory risk of the Company and the proxy group companies: (1) test year convention; (2) rate base convention; (3) revenue

[20] Moody's Investors Service. "Duke Energy Kentucky Inc.," May 13, 2024, at 5.

decoupling; (4) capital cost recovery; and (5) Construction Work in Progress (CWIP) in rate base.

As shown in Attachment JCN-9, 45 percent of the operating companies in the proxy group like Duke Energy Kentucky provide service in jurisdictions that allow the use of a fully or partially forecasted test year. Further, 43percent of the operating companies in the proxy group use average rate base like Duke Energy Kentucky, while 57 percent are allowed to use year-end rate base. Duke Energy Kentucky has limited revenue protection against fluctuations in customer demand, while approximately 51 percent of the operating companies held by the proxy group have either full or partial revenue decoupling mechanisms that protect against volumetric risk. Generally, the Company's capital investment costs must be recovered through rate cases. Approximately 78 percent of the operating companies in the proxy group have a cost recovery mechanism outside of base rate cases for capital investment (e.g., generation capacity or infrastructure replacement).

Typically, a regulatory mechanism outside of base rate cases is proposed to offset the effect of an incremental risk factor. In these circumstances, the effect of the regulatory mechanism merely restores a utility's risk profile to the position it was in prior to the incremental risk. As it relates to the determination of the cost of equity, it is important to recognize an analysis of regulatory mechanisms is a comparative assessment. For any regulatory mechanism to have an effect on the cost of equity, it would require that the mechanism changes the risk relative to the proxy companies, and investors change their return requirements as a consequence of the mechanism. As discussed above and as shown in Attachment JCN-9, the regulatory mechanisms proposed by the Company and the regulatory mechanisms employed by the proxy companies indicate that Duke Energy Kentucky and the proxy group have comparable mechanisms, and therefore similar regulatory risk profiles. As such, no adjustment to the Company's ROE is required.

VII. CAPITAL STRUCTURE

Q. WHAT IS DUKE ENERGY KENTUCKY'S PROPOSED CAPITAL STRUCTURE?

A. Duke Energy Kentucky is proposing a financial capital structure targeting a mix of 52.728 percent equity and 47.272 percent debt (42.483 percent long-term debt and 4.789 percent short-term debt).

Q. HOW HAVE YOU ASSESSED THE REASONABLENESS OF DUKE ENERGY KENTUCKY'S PROPOSED CAPITAL STRUCTURE WITH RESPECT TO THE PROXY GROUP?

A. The proxy group has been selected to reflect comparable companies in terms of business and financial risks. Therefore, it is appropriate to compare the financial capital structures of the proxy group companies to the financial capital structure proposed by the Company in order to assess whether the Company's capital structure is reasonable and consistent with industry standards for companies with commensurate risk. I calculated the weighted average capital structures for each of the proxy group operating companies for the eight quarters ended Q2 2024. Attachment JCN-10 shows that the Company's proposed common equity ratio of 52.728 percent is within the range of actual common equity ratios of 45.07 percent to 60.12 percent for the operating companies held by the proxy group over this period. Further, Duke Energy Kentucky's proposed common equity ratio is consistent with the proxy group average actual common equity ratio of 52.60 percent.

Q. WHAT IS YOUR CONCLUSION REGARDING THE APPROPRIATENESS OF DUKE ENERGY KENTUCKY'S PROPOSED CAPITAL STRUCTURE IN THIS PROCEEDING?

A. Based on the analysis presented in Attachment JCN-10, my conclusion is that Duke Energy Kentucky's proposed capital structure is reasonable. Sufficient equity in the capital structure is an important factor for maintaining Duke Energy Kentucky's financial integrity and investment grade credit rating and it is an essential component of Duke Energy Kentucky's financial policies enabling access to capital on favorable terms in a variety of market circumstances.

VIII. CONCLUSION

Q. WHAT IS YOUR CONCLUSION REGARDING A FAIR ROE FOR DUKE ENERGY KENTUCKY?

A. Based on the quantitative analyses provided in my Direct Testimony, I have established a range of ROE results shown previously in Figure 1 (also see Attachment JCN-2). The DCF, CAPM, and Bond Yield Risk Premium, analysis produce a range of estimates of the Company's cost of equity of 10.23 percent to 12.82 percent. Based on these analyses, I consider an ROE range of 10.25 percent to 11.25 percent to be reasonable. From within that range, and considering the

Company's risk profile, I recommend an ROE of 10.85 percent, which is slightly above the midpoint of my recommended range of reasonableness.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THE CAPITAL STRUCTURE FOR DUKE ENERGY KENTUCKY IN THIS PROCEEDING?

A. I support Duke Energy Kentucky's actual capital structure of 52.728 percent equity and 47.272 percent debt (42.483 percent long-term debt and 4.789 percent short-term debt) as reasonable relative to the range of capital structures for the operating companies held by the proxy group companies.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

JOSHUA C. NOWAK

VICE PRESIDENT

Mr. Nowak is a financial and economic consultant with more than fifteen years of experience in the energy industry. He has provided expert testimony on regulatory issues in several proceedings before the Federal Energy Regulatory Commission and regulatory commissions in Alaska, California, Connecticut, Kentucky, Minnesota, New Brunswick, New Hampshire, New York, North Dakota, Ohio, and Texas. Mr. Nowak specializes in providing rate case services on economic conditions and financial market matters related to the cost of capital. He is also experienced in providing strategic direction on financing activities including bond offerings, credit rating analysis, and investor relations. Previously, Josh was the Director of Regulatory Strategy & Integrated Analytics at National Grid where he was responsible for issues related to the cost of capital across its federal and state jurisdictional operating companies. He holds a Bachelor's Degree in Economics and History from Boston College.

REPRESENTATIVE EXPERIENCE

Expert Testimony and Litigation Support

Mr. Nowak's work includes regulatory project management, research, and analysis for expert witness testimony. His work has included:

- Expert testimony on cost of capital, financial markets, return on equity, capital structure, and debt financing issues
- Regulatory strategy in return on equity proceedings, including coordination across several utilities in joint-party proceedings
- Extensive support for expert testimony in cost of capital and return on equity proceedings through research, financial analysis, and testimony development
- Expert testimony, sponsoring lead-lag studies, in support of utility cash working capital requirements
- Project management of expert testimony assignments, including all phases of the regulatory schedule
- Performing analysis to support expert testimony regarding affiliate expenses and allocations

Policy Analysis

Mr. Nowak has contributed to projects related to policy review including:

- A review of natural gas capacity options and a cost-benefit analysis for state regulators seeking to reduce energy costs for ratepayers
- Analysis of the economic and environmental benefits of changes to natural gas ratemaking/expansion policy

Management and Operations Consulting

Mr. Nowak has taken a lead analytical role in developing benchmarking analyses and process reviews. Specifically, he has:

- Developed benchmarking analyses, in support of expert testimony, comparing electric and gas utilities' cost and operational efficiency, taking into account a situational assessment of exogenous factors
- Performed a process review of a gas utility's expansion projects, including an evaluation of policies, procedures, and financial models
- Supported analysis for a report of the reasonableness of a shared service company's administrative and general costs

Financial Analysis

Other financial analysis Mr. Nowak has conducted include:

- Extensive analysis on issues related to utilities' cost of capital
- Developing dispatch models to estimate revenues for merchant powerplants
- Estimating damages for breach of contract in fuel delivery commitment
- Researching strategic investment opportunities for merchant generators
- A report on the profitability of various generation technologies in a deregulated energy market
- Reviewing internal financial models used by utility clients
- Supporting utility asset appraisals, including research and analysis for income approach, cost approach, and sales comparison approach

Other Experience

In his previous work, Mr. Nowak contributed to the evaluation of regulatory policy for government clients. His experience included performing policy analysis, including economic impact assessments, for federal regulations.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2018 – Present)
Vice President
Assistant Vice President

National Grid USA (2017 – 2018)
Director, Regulatory Strategy & Integrated Analytics

ScottMadden, Inc. (formerly Sussex Economic Advisors, LLC) (2012 – 2016)
Director
Principal

Concentric Energy Advisors, Inc. (2007 – 2012)
Senior Consultant
Consultant
Assistant Consultant
Analyst

RTI International (2006 – 2007)
Economist

EDUCATION

Boston College
B.A., Economics and History, 2006

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Regulatory Commission of Alaska				
ENSTAR Natural Gas Company, a Division of Semco Energy, Inc.	06/16	ENSTAR Natural Gas Company, a Division of Semco Energy, Inc.	TA 285-4	Cash Working Capital
California Public Utilities Commission				
Pacific Gas and Electric Company, Southern California Edison Company, Southern California Gas Company, and San Diego Gas & Electric Company	02/24	Pacific Gas and Electric Company, Southern California Edison Company, Southern California Gas Company, and San Diego Gas & Electric Company	A.22-04-008 / A.22-04-009 / A.22-04-011 / A.22-04-012	Return on Equity Policy
Southern California Gas Company and San Diego Gas & Electric Company	01/24	Southern California Gas Company and San Diego Gas & Electric Company	A.22-04-011 / A.22-04-012	Return on Equity Policy
Connecticut Public Utilities Regulatory Authority				
Yankee Gas Services Company d/b/a Eversource Energy	11/24	Yankee Gas Services Company d/b/a Eversource Energy	Docket No. 24-12-01	Return on Equity
Aquarion Water Company of Connecticut	08/22	Aquarion Water Company of Connecticut	Docket No. 22-07-01	Return on Equity
Aquarion Water Company of Connecticut	01/22	Aquarion Water Company of Connecticut	Docket No. 13-02-20RE06	Return on Equity and Cost of Debt
Federal Energy Regulatory Commission				
San Diego Gas & Electric Company	10/24	San Diego Gas & Electric Company	ER25-270-000	Return on Equity
Power Authority of the State of New York	10/24	Power Authority of the State of New York	ER25-198-000	Return on Equity
Mid-Atlantic Offshore Development, LLC	07/24	Mid-Atlantic Offshore Development, LLC	ER24-2564-000	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric & Gas Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation	04/21	Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric & Gas Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation	EL21-66-000, ER21-1647-000	Transmission Ownership Risk and Returns
Central Hudson Gas & Electric Corporation	12/19	Central Hudson Gas & Electric Corporation	ER20-715-000	Return on Equity
Kentucky Public Service Commission				
Duke Energy Kentucky, Inc.	12/22	Duke Energy Kentucky, Inc.	Case No. 2022-00372	Return on Equity
Minnesota Public Utilities Commission				
Northern States Power Company (Xcel Energy Inc.)	11/24	Northern States Power Company (Xcel Energy Inc.)	G-002/GR-24-320	Return on Equity
Northern States Power Company (Xcel Energy Inc.)	11/23	Northern States Power Company (Xcel Energy Inc.)	G-002/GR-23-413	Return on Equity
New Brunswick Energy and Utilities Board				
New Brunswick Power Corporation (NB Power)	11/22	New Brunswick Power Corporation (NB Power)	Matter 541	Macroeconomic Environment and Capital Market Conditions
Public Utilities Commission of New Hampshire				
Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities	04/16	Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities	Docket No. DE 16-383	Cash Working Capital

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
New York Public Service Commission				
Central Hudson Gas & Electric Corporation	08/24	Central Hudson Gas & Electric Corporation	Case 24-E-0461/ Case 24-G-0462	Return on Equity
Niagara Mohawk Power Corporation d/b/a National Grid	05/24	Niagara Mohawk Power Corporation d/b/a National Grid	Case 24-E-0322/ Case 24-G- 0323	Return on Equity
National Fuel Gas Distribution Corporation	10/23	National Fuel Gas Distribution Corporation	Case 23-G-0627	Return on Equity
Central Hudson Gas & Electric Corporation	07/23	Central Hudson Gas & Electric Corporation	Case 23-E-0418/ Case 23-G-0419	Return on Equity
The Brooklyn Union Gas Company d/b/a National Grid NY ("KEDNY) and KeySpan Gas East Corporation d/b/a National Grid ("KEDLI")	04/23	The Brooklyn Union Gas Company d/b/a National Grid NY ("KEDNY) and KeySpan Gas East Corporation d/b/a National Grid ("KEDLI")	Case 23-G-0225/ Case 23-G-0226	Return on Equity
Niagara Mohawk Power Corporation d/b/a National Grid	07/20	Niagara Mohawk Power Corporation d/b/a National Grid	Case 20-E-0380/ Case 20-G- 0381	Return on Equity
Niagara Mohawk Power Corporation d/b/a National Grid	07/17	Niagara Mohawk Power Corporation d/b/a National Grid	Case 17-E-0238/ Case 17-G- 0239	Capital Structure and Overall Cost of Capital

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
North Dakota Public Service Commission				
Northern States Power Company (Xcel Energy Inc.)	12/23	Northern States Power Company (Xcel Energy Inc.)	Docket No. PU-23-367	Return on Equity
Public Utilities Commission of Ohio				
Duke Energy Ohio, Inc.	01/23	Duke Energy Ohio, Inc.	Case No. 22-1153-EL-UNC	Return on Equity
Public Utility Commission of Texas				
Wind Energy Transmission Texas, LLC	05/15	Wind Energy Transmission Texas, LLC	Docket No. 44746	Cash Working Capital
Lone Star Transmission, LLC	05/14	Lone Star Transmission, LLC	Docket No. 42469	Cash Working Capital
Railroad Commission of Texas				
Texas Gas Service Company, a Division of One Gas, Inc.	06/16	Texas Gas Service Company, a Division of One Gas, Inc.	GUD No. 10526	Cash Working Capital
Texas Gas Service Company, a Division of One Gas, Inc.	03/16	Texas Gas Service Company, a Division of One Gas, Inc.	GUD No. 10506	Cash Working Capital
Texas Gas Service Company, a Division of One Gas, Inc.	12/15	Texas Gas Service Company, a Division of One Gas, Inc.	GUD No. 10488	Cash Working Capital
CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	03/14	CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD No. 10432	Cash Working Capital

SUMMARY OF RESULTS

Company	Ticker	*Primary Analyses*															*Benchmark Analysis*	**Average of DCF, CAPM, and Risk Premium**
		CONSTANT GROWTH DCF				**CAPM**							**Risk Premium (Average)**					
						Value Line Beta			Bloomberg Beta									
		30-Day Average	90-Day Average	180-Day Average	***Average***	Current Yield	Near-Term Projected Yield	Long-Term Projected Yield	Current Yield	Near-Term Projected Yield	Long-Term Projected Yield	***Average***	Current Yield	Near-Term Projected Yield	Long-Term Projected Yield	***Average***	**Expected Earnings**	
Alliant Energy Corporation	LNT	10.11%	10.28%	10.54%	**10.31%**	12.34%	12.33%	12.34%	11.20%	11.17%	11.20%	**11.76%**	10.46%	10.41%	10.46%	**10.44%**	12.23%	**10.84%**
Ameren Corporation	AEE	9.60%	9.82%	10.02%	**9.81%**	12.34%	12.33%	12.34%	10.84%	10.81%	10.84%	**11.58%**	10.46%	10.41%	10.46%	**10.44%**	10.27%	**10.61%**
American Electric Power Company, Inc.	AEP	10.07%	10.16%	10.39%	**10.21%**	11.90%	11.88%	11.90%	10.89%	10.86%	10.88%	**11.38%**	10.46%	10.41%	10.46%	**10.44%**	11.22%	**10.68%**
Entergy Corporation	ETR	8.43%	8.77%	9.03%	**8.74%**	13.24%	13.24%	13.24%	11.79%	11.77%	11.79%	**12.51%**	10.46%	10.41%	10.46%	**10.44%**	9.78%	**10.56%**
Evergy, Inc.	EVRG	10.86%	11.03%	11.28%	**11.05%**	12.79%	12.79%	12.79%	11.14%	11.12%	11.14%	**11.96%**	10.46%	10.41%	10.46%	**10.44%**	10.12%	**11.15%**
IDACORP, Inc.	IDA	8.99%	9.07%	9.21%	**9.09%**	11.90%	11.88%	11.90%	11.14%	11.11%	11.14%	**11.51%**	10.46%	10.41%	10.46%	**10.44%**	9.24%	**10.35%**
NextEra Energy, Inc.	NEE	10.67%	10.80%	11.03%	**10.84%**	13.68%	13.69%	13.68%	11.45%	11.43%	11.45%	**12.56%**	10.46%	10.41%	10.46%	**10.44%**	14.12%	**11.28%**
NorthWestern Corporation	NWE	10.19%	10.37%	10.54%	**10.37%**	13.24%	13.24%	13.24%	11.96%	11.94%	11.96%	**12.60%**	10.46%	10.41%	10.46%	**10.44%**	8.14%	**11.14%**
OGE Energy Corporation	OGE	10.13%	10.28%	10.56%	**10.32%**	13.68%	13.69%	13.68%	12.24%	12.23%	12.24%	**12.96%**	10.46%	10.41%	10.46%	**10.44%**	13.16%	**11.24%**
Pinnacle West Capital Corporation	PNW	10.76%	10.88%	11.19%	**10.94%**	12.79%	12.79%	12.79%	11.45%	11.43%	11.45%	**12.12%**	10.46%	10.41%	10.46%	**10.44%**	8.80%	**11.17%**
TXNM Energy, Inc.	TXNM	8.35%	8.55%	8.75%	**8.55%**	12.34%	12.33%	12.34%	11.48%	11.46%	11.48%	**11.91%**	10.46%	10.41%	10.46%	**10.44%**	10.30%	**10.30%**
Portland General Electric Company	POR	14.82%	14.89%	15.11%	**14.94%**	12.79%	12.79%	12.79%	11.13%	11.11%	11.13%	**11.96%**	10.46%	10.41%	10.46%	**10.44%**	9.78%	**12.45%**
PPL Corporation	PPL	10.31%	10.48%	10.67%	**10.49%**	14.58%	14.59%	14.58%	12.59%	12.58%	12.59%	**13.59%**	10.46%	10.41%	10.46%	**10.44%**	9.71%	**11.50%**
Southern Company	SO	10.22%	10.37%	10.66%	**10.42%**	12.79%	12.79%	12.79%	11.12%	11.10%	11.12%	**11.95%**	10.46%	10.41%	10.46%	**10.44%**	14.64%	**10.94%**
Xcel Energy Inc.	XEL	9.91%	10.13%	10.32%	**10.12%**	11.90%	11.88%	11.90%	10.68%	10.65%	10.67%	**11.28%**	10.46%	10.41%	10.46%	**10.44%**	11.34%	**10.61%**
Low		8.35%	8.55%	8.75%	**8.55%**	11.90%	11.88%	11.90%	10.68%	10.65%	10.67%	**11.28%**					8.14%	**10.30%**
Median		10.13%	10.28%	10.54%	**10.32%**	12.79%	12.79%	12.79%	11.20%	11.17%	11.20%	**11.96%**	10.46%	10.41%	10.46%	**10.44%**	10.27%	**10.94%**
Mean		10.23%	10.39%	10.62%	**10.41%**	12.82%	12.82%	12.82%	11.41%	11.39%	11.41%	**12.11%**	10.46%	10.41%	10.46%	**10.44%**	10.86%	**10.99%**
High		14.82%	14.89%	15.11%	**14.94%**	14.58%	14.59%	14.58%	12.59%	12.58%	12.59%	**13.59%**					14.64%	**12.45%**

PROXY GROUP SCREENING DATA AND RESULTS - PROXY GROUP

Company	Ticker	[1] Dividends	[2] S&P Credit Rating Between BBB- and AAA	[3] Covered by More Than 1 Analyst	[4] Postive Growth Rates From At Least 2 Sources	[5] Company-Owned Generation Assets Included in Rate Base	T [7] % Regulated Operating Income of Total Income > 80%	W [9] % Regulated Electric Income of Total Regulated Income	[10] Significant Merger or Transaction
ALLETE, Inc.	ALE	Yes	BBB	Yes	Yes	Yes	98.08%	98.13%	Yes
Alliant Energy Corporation	LNT	Yes	A-	Yes	Yes	Yes	97.09%	90.82%	No
Ameren Corporation	AEE	Yes	BBB+	Yes	Yes	Yes	98.34%	84.73%	No
American Electric Power Company, Inc.	AEP	Yes	BBB+	Yes	Yes	Yes	97.85%	100.00%	No
Avangrid, Inc.	AGR	Yes	BBB+	Yes	Yes	Yes	99.29%	78.50%	Yes
Avista Corporation	AVA	Yes	BBB	Yes	Yes	Yes	100.00%	73.88%	No
Black Hills Corporation	BKH	Yes	BBB+	Yes	Yes	Yes	100.00%	49.27%	No
CenterPoint Energy, Inc.	CNP	Yes	BBB+	Yes	Yes	Yes	100.00%	59.10%	Yes
CMS Energy Corporation	CMS	Yes	BBB+	Yes	Yes	Yes	85.56%	63.61%	No
Consolidated Edison, Inc.	ED	Yes	A-	Yes	Yes	Yes	83.65%	71.55%	No
Dominion Resources, Inc.	D	Yes	BBB+	Yes	Yes	Yes	92.34%	100.00%	Yes
DTE Energy Company	DTE	Yes	BBB+	Yes	Yes	Yes	89.70%	77.38%	No
Edison International	EIX	Yes	BBB	Yes	Yes	No	100.74%	100.00%	No
Entergy Corporation	ETR	Yes	BBB+	Yes	Yes	Yes	98.52%	99.32%	No
Eversource Energy	ES	Yes	A-	Yes	Yes	Yes	94.96%	81.41%	Yes
Exelon Corporation	EXC	Yes	BBB+	Yes	Yes	No	100.00%	90.51%	No
FirstEnergy Corporation	FE	Yes	BBB	Yes	Yes	Yes	100.00%	100.00%	Yes
Evergy, Inc.	EVRG	Yes	BBB+	Yes	Yes	Yes	100.00%	100.00%	No
Hawaiian Electric Industries, Inc.	HE	No	B-	Yes	No	Yes	78.87%	100.00%	No
IDACORP, Inc.	IDA	Yes	BBB	Yes	Yes	Yes	99.98%	100.00%	No
MGE Energy, Inc.	MGEE	Yes	AA-	No	No	Yes	74.71%	68.51%	No
NextEra Energy, Inc.	NEE	Yes	A-	Yes	Yes	Yes	87.65%	100.00%	No
NorthWestern Corporation	NWE	Yes	BBB	Yes	Yes	Yes	99.96%	85.62%	No
OGE Energy Corporation	OGE	Yes	BBB+	Yes	Yes	Yes	100.00%	100.00%	No
Otter Tail Corporation	OTTR	Yes	BBB	Yes	Yes	Yes	33.33%	100.00%	No
PG&E Corporation	PCG	No	BB	Yes	Yes	Yes	100.00%	50.17%	No
Pinnacle West Capital Corporation	PNW	Yes	BBB+	Yes	Yes	Yes	100.00%	100.00%	No
TXNM Energy, Inc.	TXNM	Yes	BBB	Yes	Yes	Yes	100.00%	100.00%	No
Portland General Electric Company	POR	Yes	BBB+	Yes	Yes	Yes	100.00%	100.00%	No
PPL Corporation	PPL	Yes	A-	Yes	Yes	Yes	100.00%	94.16%	No
Public Service Enterprise Group Inc.	PEG	Yes	BBB+	Yes	Yes	Yes	83.86%	78.96%	No
Sempra Energy	SRE	Yes	BBB+	Yes	Yes	Yes	46.73%	61.56%	No
Southern Company	SO	Yes	A-	Yes	Yes	Yes	93.73%	81.54%	No
Unitil Corporation	UTL	Yes	BBB+	Yes	No	n/a	100.00%	35.30%	Yes
Wisconsin Energy Corporation	WEC	Yes	A-	Yes	Yes	Yes	98.56%	56.62%	No
Xcel Energy Inc.	XEL	Yes	BBB+	Yes	Yes	Yes	100.00%	85.90%	No

Notes:
[1] Source: Bloomberg Professional
[2] Source: SNL Financial
[3] Source: Yahoo! Finance and Zacks
[4] Source: Yahoo! Finance, Value Line Investment Survey, and Zacks
[5] Source: SNL Financial
[6] - [9] Source: Form 10-Ks for 2021, 2022, & 2023, three-year average
[10] SNL Financial News Releases

30-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE
Alliant Energy Corporation	LNT	$1.92	$60.53	3.17%	3.28%	6.00%	7.70%	6.80%	6.83%	9.27%	10.11%	10.99%
Ameren Corporation	AEE	$2.68	$87.24	3.07%	3.17%	6.50%	6.20%	6.60%	6.43%	9.37%	9.60%	9.77%
American Electric Power Company, Inc.	AEP	$3.52	$100.00	3.52%	3.63%	6.50%	6.62%	6.20%	6.44%	9.83%	10.07%	10.26%
Entergy Corporation	ETR	$4.52	$133.42	3.39%	3.47%	0.50%	7.08%	7.30%	4.96%	3.90%	8.43%	10.81%
Evergy, Inc.	EVRG	$2.57	$60.85	4.22%	4.36%	7.50%	6.20%	5.80%	6.50%	10.15%	10.86%	11.88%
IDACORP, Inc.	IDA	$3.32	$102.82	3.23%	3.32%	6.00%	5.50%	5.50%	5.67%	8.82%	8.99%	9.33%
NextEra Energy, Inc.	NEE	$2.06	$82.96	2.48%	2.58%	8.00%	8.17%	8.10%	8.09%	10.58%	10.67%	10.75%
NorthWestern Corporation	NWE	$2.60	$55.70	4.67%	4.79%	4.00%	6.10%	6.10%	5.40%	8.76%	10.19%	10.91%
OGE Energy Corporation	OGE	$1.69	$40.54	4.16%	4.28%	6.50%	Negative	5.20%	5.85%	9.46%	10.13%	10.79%
Pinnacle West Capital Corporation	PNW	$3.52	$88.10	4.00%	4.13%	4.50%	7.20%	8.20%	6.63%	8.59%	10.76%	12.36%
TXNM Energy, Inc.	TXNM	$1.55	$43.54	3.56%	3.64%	5.00%	4.42%	n/a	4.71%	8.06%	8.35%	8.65%
Portland General Electric Company	POR	$2.00	$47.64	4.20%	4.42%	6.00%	12.60%	12.60%	10.40%	10.32%	14.82%	17.06%
PPL Corporation	PPL	$1.03	$32.51	3.17%	3.28%	7.50%	6.80%	6.80%	7.03%	10.08%	10.31%	10.79%
Southern Company	SO	$2.88	$90.75	3.17%	3.28%	6.50%	7.30%	7.00%	6.93%	9.78%	10.22%	10.59%
Xcel Energy Inc.	XEL	$2.19	$63.95	3.42%	3.53%	6.00%	6.73%	6.40%	6.38%	9.53%	9.91%	10.27%
Median				3.42%	3.53%	6.00%	6.77%	6.70%	6.44%	9.46%	10.13%	10.79%
Mean				3.56%	3.68%	5.80%	7.04%	7.04%	6.55%	9.10%	10.23%	11.01%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of October 31, 2024
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] Yahoo! Finance Earnings Growth	[7] Zacks Earnings Growth	[8] Average Growth Rate	[9] Low ROE	[10] Mean ROE	[11] High ROE
Alliant Energy Corporation	LNT	$1.92	$57.56	3.34%	3.45%	6.00%	7.70%	6.80%	6.83%	9.44%	10.28%	11.16%
Ameren Corporation	AEE	$2.68	$81.71	3.28%	3.39%	6.50%	6.20%	6.60%	6.43%	9.58%	9.82%	9.99%
American Electric Power Company, Inc.	AEP	$3.52	$97.74	3.60%	3.72%	6.50%	6.62%	6.20%	6.44%	9.91%	10.16%	10.34%
Entergy Corporation	ETR	$4.52	$121.72	3.71%	3.81%	0.50%	7.08%	7.30%	4.96%	4.22%	8.77%	11.15%
Evergy, Inc.	EVRG	$2.57	$58.62	4.38%	4.53%	7.50%	6.20%	5.80%	6.50%	10.31%	11.03%	12.05%
IDACORP, Inc.	IDA	$3.32	$100.39	3.31%	3.40%	6.00%	5.50%	5.50%	5.67%	8.90%	9.07%	9.41%
NextEra Energy, Inc.	NEE	$2.06	$79.02	2.61%	2.71%	8.00%	8.17%	8.10%	8.09%	10.71%	10.80%	10.88%
NorthWestern Corporation	NWE	$2.60	$53.77	4.84%	4.97%	4.00%	6.10%	6.10%	5.40%	8.93%	10.37%	11.08%
OGE Energy Corporation	OGE	$1.69	$39.12	4.31%	4.43%	6.50%	Negative	5.20%	5.85%	9.62%	10.28%	10.95%
Pinnacle West Capital Corporation	PNW	$3.52	$85.69	4.11%	4.24%	4.50%	7.20%	8.20%	6.63%	8.70%	10.88%	12.48%
TXNM Energy, Inc.	TXNM	$1.55	$41.26	3.76%	3.84%	5.00%	4.42%	n/a	4.71%	8.26%	8.55%	8.85%
Portland General Electric Company	POR	$2.00	$46.88	4.27%	4.49%	6.00%	12.60%	12.60%	10.40%	10.39%	14.89%	17.14%
PPL Corporation	PPL	$1.03	$30.97	3.33%	3.44%	7.50%	6.80%	6.80%	7.03%	10.24%	10.48%	10.95%
Southern Company	SO	$2.88	$86.61	3.33%	3.44%	6.50%	7.30%	7.00%	6.93%	9.93%	10.37%	10.75%
Xcel Energy Inc.	XEL	$2.19	$60.28	3.63%	3.75%	6.00%	6.73%	6.40%	6.38%	9.74%	10.13%	10.49%
Median				3.63%	3.75%	6.00%	6.77%	6.70%	6.44%	9.62%	10.28%	10.95%
Mean				3.72%	3.84%	5.80%	7.04%	7.04%	6.55%	9.26%	10.39%	11.18%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of October 31, 2024
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE
Alliant Energy Corporation	LNT	$1.92	$53.63	3.58%	3.70%	6.00%	7.70%	6.80%	6.83%	9.69%	10.54%	11.42%
Ameren Corporation	AEE	$2.68	$77.09	3.48%	3.59%	6.50%	6.20%	6.60%	6.43%	9.78%	10.02%	10.19%
American Electric Power Company, Inc.	AEP	$3.52	$91.88	3.83%	3.95%	6.50%	6.62%	6.20%	6.44%	10.15%	10.39%	10.58%
Entergy Corporation	ETR	$4.52	$113.85	3.97%	4.07%	0.50%	7.08%	7.30%	4.96%	4.48%	9.03%	11.41%
Evergy, Inc.	EVRG	$2.57	$55.54	4.63%	4.78%	7.50%	6.20%	5.80%	6.50%	10.56%	11.28%	12.30%
IDACORP, Inc.	IDA	$3.32	$96.46	3.44%	3.54%	6.00%	5.50%	5.50%	5.67%	9.04%	9.21%	9.54%
NextEra Energy, Inc.	NEE	$2.06	$72.86	2.83%	2.94%	8.00%	8.17%	8.10%	8.09%	10.94%	11.03%	11.11%
NorthWestern Corporation	NWE	$2.60	$51.91	5.01%	5.14%	4.00%	6.10%	6.10%	5.40%	9.11%	10.54%	11.26%
OGE Energy Corporation	OGE	$1.69	$36.85	4.57%	4.71%	6.50%	Negative	5.20%	5.85%	9.89%	10.56%	11.22%
Pinnacle West Capital Corporation	PNW	$3.52	$79.77	4.41%	4.56%	4.50%	7.20%	8.20%	6.63%	9.01%	11.19%	12.79%
TXNM Energy, Inc.	TXNM	$1.55	$39.27	3.95%	4.04%	5.00%	4.42%	n/a	4.71%	8.45%	8.75%	9.05%
Portland General Electric Company	POR	$2.00	$44.64	4.48%	4.71%	6.00%	12.60%	12.60%	10.40%	10.62%	15.11%	17.36%
PPL Corporation	PPL	$1.03	$29.31	3.51%	3.64%	7.50%	6.80%	6.80%	7.03%	10.43%	10.67%	11.15%
Southern Company	SO	$2.88	$79.97	3.60%	3.73%	6.50%	7.30%	7.00%	6.93%	10.22%	10.66%	11.03%
Xcel Energy Inc.	XEL	$2.19	$57.25	3.83%	3.95%	6.00%	6.73%	6.40%	6.38%	9.94%	10.32%	10.68%
Median				3.83%	3.95%	6.00%	6.77%	6.70%	6.44%	9.89%	10.54%	11.15%
Mean				3.94%	4.07%	5.80%	7.04%	7.04%	6.55%	9.49%	10.62%	11.41%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of October 31, 2024
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

MARKET RISK PREMIUM DERIVED FROM S&P 500 - ALL COMPANIES

[1] Estimate of the S&P 500 Dividend Yield	1.34%
[2] Estimate of the S&P 500 Growth Rate	13.63%
[3] S&P 500 Estimated Required Market Return	15.07%

Notes:
[1] Sum of [9]
[2] Sum of [11]
[3] Equals ([1] x (1 + 0.5 x [2])) + [2]

STANDARD AND POOR'S 500 INDEX

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Price	Shares Outstanding	Market Capitalization	Weight in Index	Current Dividend Yield	Cap-Weighted Dividend Yield	Value Line Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	86.85	325	28,234	0.06%	6.17%	0.00%	-1.00%	0.00%
American Express Co	AXP	270.08	704	190,257	0.40%	1.04%	0.00%	9.00%	0.04%
Verizon Communications Inc	VZ	42.13	4,210	177,352	0.37%	6.43%	0.02%	0.50%	0.00%
Broadcom Inc	AVGO	169.77	4,671	792,924	1.67%	1.25%	0.02%	30.00%	0.50%
Boeing Co/The	BA	149.31	730	Excl.	0.00%	n/a	n/a		n/a
Solventum Corp	SOLV	72.58	173	Excl.	0.00%	n/a	n/a		n/a
Caterpillar Inc	CAT	376.20	485	182,419	0.38%	1.50%	0.01%	11.50%	0.04%
JPMorgan Chase & Co	JPM	221.92	2,815	624,780	1.31%	2.25%	0.03%	7.00%	0.09%
Chevron Corp	CVX	148.82	1,829	272,179	0.57%	4.38%	0.03%	5.00%	0.03%
Coca-Cola Co/The	KO	65.31	4,308	281,342	0.59%	2.97%	0.02%	7.00%	0.04%
AbbVie Inc	ABBV	203.87	1,766	360,105	0.76%	3.22%	0.02%	4.00%	0.03%
Walt Disney Co/The	DIS	96.20	1,814	174,467	0.37%	0.94%	0.00%	31.50%	0.12%
Corpay Inc	CPAY	329.72	69	22,893	0.05%	n/a	n/a	15.50%	0.01%
Extra Space Storage Inc	EXR	163.30	212	34,608	0.07%	3.97%	0.00%	5.00%	0.00%
Exxon Mobil Corp	XOM	116.78	4,443	518,833	1.09%	3.25%	0.04%	-3.00%	-0.03%
Phillips 66	PSX	121.82	413	50,310	0.11%	3.78%	0.00%	0.50%	0.00%
General Electric Co	GE	171.78	1,082	185,916	0.39%	0.65%	0.00%	22.00%	0.09%
HP Inc	HPQ	35.52	964	34,231	0.07%	3.10%	0.00%	12.50%	0.01%
Home Depot Inc/The	HD	393.75	993	391,109	0.82%	2.29%	0.02%	6.50%	0.05%
Monolithic Power Systems Inc	MPWR	759.30	49	37,017	0.08%	0.66%	0.00%	10.50%	0.01%
International Business Machines Corp	IBM	206.72	925	191,143	0.40%	3.23%	0.01%	3.00%	0.01%
Johnson & Johnson	JNJ	159.86	2,408	384,883	0.81%	3.10%	0.03%	3.00%	0.02%
Lululemon Athletica Inc	LULU	297.90	118	35,051	0.07%	n/a	n/a	13.00%	0.01%
McDonald's Corp	MCD	292.11	717	209,543	0.44%	2.42%	0.01%	8.00%	0.04%
Merck & Co Inc	MRK	102.32	2,535	259,362	0.55%	3.01%	0.02%	15.50%	0.08%
3M Co	MMM	128.47	545	69,959	0.15%	2.18%	0.00%	30.50%	0.04%
American Water Works Co Inc	AWK	138.11	195	26,917	0.06%	2.22%	0.00%	4.50%	0.00%
Bank of America Corp	BAC	41.82	7,673	320,880	0.67%	2.49%	0.02%	7.00%	0.05%
Pfizer Inc	PFE	28.30	5,667	160,367	0.34%	5.94%	0.02%	2.50%	0.01%
Procter & Gamble Co/The	PG	165.18	2,355	389,006	0.82%	2.44%	0.02%	5.00%	0.04%
AT&T Inc	T	22.54	7,175	161,731	0.34%	4.92%	0.02%	4.00%	0.01%
Travelers Cos Inc/The	TRV	245.94	227	55,833	0.12%	1.71%	0.00%	12.00%	0.01%
RTX Corp	RTX	120.99	1,331	161,040	0.34%	2.08%	0.01%	12.00%	0.04%
Analog Devices Inc	ADI	223.11	496	110,773	0.23%	1.65%	0.00%	7.50%	0.02%
Walmart Inc	WMT	81.95	8,038	658,735	1.38%	1.01%	0.01%	9.50%	0.13%
Cisco Systems Inc	CSCO	54.77	3,986	218,314	0.46%	2.92%	0.01%	3.50%	0.02%
Intel Corp	INTC	21.52	4,276	92,020	0.19%	n/a	n/a	-2.00%	0.00%
General Motors Co	GM	50.76	1,100	55,815	0.12%	0.95%	0.00%	6.50%	0.01%
Microsoft Corp	MSFT	406.35	7,435	3,021,164	6.35%	0.82%	0.05%	14.00%	0.89%
Dollar General Corp	DG	80.04	220	17,602	0.04%	2.95%	0.00%	-0.50%	0.00%
Cigna Group/The	CI	314.81	278	87,565	0.18%	1.78%	0.00%	12.00%	0.02%
Kinder Morgan Inc	KMI	24.51	2,222	54,452	0.11%	4.69%	0.01%	10.00%	0.01%
Citigroup Inc	C	64.17	1,908	122,423	0.26%	3.49%	0.01%	3.00%	0.01%
American International Group Inc	AIG	75.88	644	48,863	0.10%	2.11%	0.00%	13.00%	0.01%
Altria Group Inc	MO	54.46	1,695	92,300	0.19%	7.49%	0.01%	6.00%	0.01%
HCA Healthcare Inc	HCA	358.74	253	90,868	0.19%	0.74%	0.00%	10.50%	0.02%
International Paper Co	IP	55.54	347	19,293	0.04%	3.33%	0.00%	5.50%	0.00%
Hewlett Packard Enterprise Co	HPE	19.49	1,299	25,311	0.05%	2.67%	0.00%	7.50%	0.00%
Abbott Laboratories	ABT	113.37	1,734	196,635	0.41%	1.94%	0.01%	4.00%	0.02%
Aflac Inc	AFL	104.79	560	58,685	0.12%	1.91%	0.00%	7.50%	0.01%
Air Products and Chemicals Inc	APD	310.53	222	69,035	0.15%	2.28%	0.00%	10.50%	0.02%
Super Micro Computer Inc	SMCI	29.11	586	17,046	0.04%	n/a	n/a	39.00%	0.01%
Royal Caribbean Cruises Ltd	RCL	206.35	269	Excl.	0.00%	0.78%	0.00%		n/a
Hess Corp	HES	134.48	308	41,435	0.09%	1.49%	0.00%	8.00%	0.01%
Archer-Daniels-Midland Co	ADM	55.21	478	26,398	0.06%	3.62%	0.00%	3.50%	0.00%
Automatic Data Processing Inc	ADP	289.24	408	117,960	0.25%	1.94%	0.00%	10.50%	0.03%
Verisk Analytics Inc	VRSK	274.72	141	38,793	0.08%	0.57%	0.00%	8.50%	0.01%
AutoZone Inc	AZO	3,009.00	17	50,865	0.11%	n/a	n/a	12.50%	0.01%
Linde PLC	LIN	456.15	476	217,199	0.46%	1.22%	0.01%	7.00%	0.03%
Avery Dennison Corp	AVY	207.03	80	16,634	0.03%	1.70%	0.00%	2.00%	0.00%
Enphase Energy Inc	ENPH	83.04	135	11,219	0.02%	n/a	n/a	14.00%	0.00%
MSCI Inc	MSCI	571.20	78	44,766	0.09%	1.12%	0.00%	9.50%	0.01%

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Name	Ticker	[4] Price	[5] Shares Outstanding	[6] Market Capitalization	[7] Weight in Index	[8] Current Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Ball Corp	BALL	59.25	298	17,682	0.04%	1.35%	0.00%	10.50%	0.00%
Axon Enterprise Inc	AXON	423.50	76	32,006	0.07%	n/a	n/a	25.00%	0.02%
Dayforce Inc	DAY	70.95	158	Excl.	0.00%	n/a	n/a		n/a
Carrier Global Corp	CARR	72.72	897	65,246	0.14%	1.05%	0.00%	12.00%	0.02%
Bank of New York Mellon Corp/The	BK	75.36	738	55,612	0.12%	2.49%	0.00%	15.00%	0.02%
Otis Worldwide Corp	OTIS	98.20	399	39,227	0.08%	1.59%	0.00%	11.00%	0.01%
Baxter International Inc	BAX	35.70	510	18,213	0.04%	3.25%	0.00%	3.00%	0.00%
Becton Dickinson & Co	BDX	233.59	289	67,517	0.14%	1.63%	0.00%	6.00%	0.01%
Berkshire Hathaway Inc	BRK/B	450.92	1,325	597,556	1.26%	n/a	n/a	9.00%	0.11%
Best Buy Co Inc	BBY	90.43	215	19,418	0.04%	4.16%	0.00%	1.00%	0.00%
Boston Scientific Corp	BSX	84.02	1,473	123,730	0.26%	n/a	n/a	13.00%	0.03%
Bristol-Myers Squibb Co	BMY	55.77	2,028	113,111	0.24%	4.30%	0.01%	1.00%	0.00%
Brown-Forman Corp	BF/B	44.03	304	13,365	0.03%	1.98%	0.00%	15.00%	0.00%
Coterra Energy Inc	CTRA	23.92	739	17,683	0.04%	3.51%	0.00%	4.50%	0.00%
Hilton Worldwide Holdings Inc	HLT	234.85	244	Excl.	0.00%	0.26%	0.00%		n/a
Carnival Corp	CCL	22.00	1,154	Excl.	0.00%	n/a	n/a		n/a
Qorvo Inc	QRVO	71.26	95	6,736	0.01%	n/a	n/a	5.50%	0.00%
Builders FirstSource Inc	BLDR	171.40	116	19,960	0.04%	n/a	n/a	6.50%	0.00%
UDR Inc	UDR	42.19	330	13,921	0.03%	4.03%	0.00%	2.50%	0.00%
Clorox Co/The	CLX	158.55	124	19,625	0.04%	3.08%	0.00%	7.00%	0.00%
Paycom Software Inc	PAYC	209.03	58	12,053	0.03%	0.72%	0.00%	21.00%	0.01%
CMS Energy Corp	CMS	69.61	299	20,798	0.04%	2.96%	0.00%	6.00%	0.00%
Colgate-Palmolive Co	CL	93.71	817	76,562	0.16%	2.13%	0.00%	11.50%	0.02%
EPAM Systems Inc	EPAM	188.65	57	10,741	0.02%	n/a	n/a	20.50%	0.00%
Conagra Brands Inc	CAG	28.94	477	13,812	0.03%	4.84%	0.00%	3.00%	0.00%
Airbnb Inc	ABNB	134.79	440	59,308	0.12%	n/a	n/a	23.00%	0.03%
Consolidated Edison Inc	ED	101.68	346	35,196	0.07%	3.27%	0.00%	6.00%	0.00%
Corning Inc	GLW	47.59	856	40,723	0.09%	2.35%	0.00%	17.50%	0.01%
GoDaddy Inc	GDDY	166.80	140	23,417	0.05%	n/a	n/a	27.00%	0.01%
Cummins Inc	CMI	328.98	137	45,086	0.09%	2.21%	0.00%	6.00%	0.01%
Caesars Entertainment Inc	CZR	40.05	212	Excl.	0.00%	n/a	n/a		n/a
Danaher Corp	DHR	245.66	722	177,434	0.37%	0.44%	0.00%	5.50%	0.02%
Target Corp	TGT	150.04	461	69,120	0.15%	2.99%	0.00%	9.50%	0.01%
Deere & Co	DE	404.69	274	110,723	0.23%	1.45%	0.00%	4.00%	0.01%
Dominion Energy Inc	D	59.53	839	49,942	0.10%	4.49%	0.00%	3.00%	0.00%
Dover Corp	DOV	189.33	137	25,975	0.05%	1.09%	0.00%	6.00%	0.00%
Alliant Energy Corp	LNT	60.00	256	15,390	0.03%	3.20%	0.00%	6.00%	0.00%
Steel Dynamics Inc	STLD	130.50	154	20,137	0.04%	1.41%	0.00%	2.00%	0.00%
Duke Energy Corp	DUK	115.27	771	88,873	0.19%	3.63%	0.01%	5.00%	0.01%
Regency Centers Corp	REG	71.44	181	12,966	0.03%	3.75%	0.00%	11.50%	0.00%
Eaton Corp PLC	ETN	331.58	395	131,040	0.28%	1.13%	0.00%	11.00%	0.03%
Ecolab Inc	ECL	245.73	283	69,581	0.15%	0.93%	0.00%	11.00%	0.02%
Revvity Inc	RVTY	118.59	123	14,627	0.03%	0.24%	0.00%	-2.50%	0.00%
Dell Technologies Inc	DELL	123.63	334	41,277	0.09%	1.44%	0.00%	2.50%	0.00%
Emerson Electric Co	EMR	108.27	573	62,006	0.13%	1.94%	0.00%	7.00%	0.01%
EOG Resources Inc	EOG	121.96	569	69,346	0.15%	2.98%	0.00%	8.00%	0.01%
Aon PLC	AON	366.87	216	79,342	0.17%	0.74%	0.00%	12.50%	0.02%
Entergy Corp	ETR	154.78	214	33,097	0.07%	3.10%	0.00%	0.50%	0.00%
Equifax Inc	EFX	265.02	124	32,850	0.07%	0.59%	0.00%	7.00%	0.00%
EQT Corp	EQT	36.54	597	Excl.	0.00%	1.72%	0.00%		n/a
IQVIA Holdings Inc	IQV	205.82	182	37,356	0.08%	n/a	n/a	11.00%	0.01%
Gartner Inc	IT	502.50	77	38,723	0.08%	n/a	n/a	8.00%	0.01%
FedEx Corp	FDX	273.85	244	66,908	0.14%	2.02%	0.00%	3.50%	0.00%
FMC Corp	FMC	64.99	125	8,113	0.02%	3.57%	0.00%	4.00%	0.00%
Brown & Brown Inc	BRO	104.64	286	29,923	0.06%	0.57%	0.00%	12.50%	0.01%
Ford Motor Co	F	10.29	3,903	40,166	0.08%	5.83%	0.00%	35.00%	0.03%
NextEra Energy Inc	NEE	79.25	2,056	162,970	0.34%	2.60%	0.01%	8.00%	0.03%
Franklin Resources Inc	BEN	20.77	523	10,863	0.02%	5.97%	0.00%	4.00%	0.00%
Garmin Ltd	GRMN	198.35	192	38,088	0.08%	1.51%	0.00%	5.00%	0.00%
Freeport-McMoRan Inc	FCX	45.02	1,437	64,687	0.14%	1.33%	0.00%	11.00%	0.01%
Dexcom Inc	DXCM	70.48	391	Excl.	0.00%	n/a	n/a		n/a
General Dynamics Corp	GD	291.61	275	80,184	0.17%	1.95%	0.00%	10.00%	0.02%
General Mills Inc	GIS	68.02	555	37,762	0.08%	3.53%	0.00%	5.00%	0.00%
Genuine Parts Co	GPC	114.70	139	15,947	0.03%	3.49%	0.00%	8.50%	0.00%
Atmos Energy Corp	ATO	138.78	155	21,543	0.05%	2.32%	0.00%	7.00%	0.00%
WW Grainger Inc	GWW	1,109.23	49	54,020	0.11%	0.74%	0.00%	7.00%	0.01%
Halliburton Co	HAL	27.74	883	24,490	0.05%	2.45%	0.00%	18.00%	0.01%
L3Harris Technologies Inc	LHX	247.47	190	46,937	0.10%	1.87%	0.00%	11.50%	0.01%
Healthpeak Properties Inc	DOC	22.45	699	15,702	0.03%	5.35%	0.00%	7.00%	0.00%
Insulet Corp	PODD	231.53	70	Excl.	0.00%	n/a	n/a		n/a
Catalent Inc	CTLT	58.60	181	10,634	0.02%	n/a	n/a	21.00%	0.00%
Fortive Corp	FTV	71.43	347	24,783	0.05%	0.45%	0.00%	15.00%	0.01%
Hershey Co/The	HSY	177.58	148	26,224	0.06%	3.09%	0.00%	7.00%	0.00%
Synchrony Financial	SYF	55.14	389	21,468	0.05%	1.81%	0.00%	47.00%	0.02%
Hormel Foods Corp	HRL	30.55	548	16,753	0.04%	3.70%	0.00%	7.50%	0.00%
Arthur J Gallagher & Co	AJG	281.20	219	61,695	0.13%	0.85%	0.00%	14.00%	0.02%
Mondelez International Inc	MDLZ	68.48	1,337	91,571	0.19%	2.75%	0.01%	7.50%	0.01%

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Name	Ticker	Price	Shares Outstanding	Market Capitalization	Weight in Index	Current Dividend Yield	Cap-Weighted Dividend Yield	Value Line Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
CenterPoint Energy Inc	CNP	29.53	652	19,245	0.04%	2.84%	0.00%	6.50%	0.00%
Humana Inc	HUM	257.83	120	31,046	0.07%	1.37%	0.00%	4.50%	0.00%
Willis Towers Watson PLC	WTW	302.19	101	30,438	0.06%	1.16%	0.00%	9.50%	0.01%
Illinois Tool Works Inc	ITW	261.13	295	77,112	0.16%	2.30%	0.00%	9.00%	0.01%
CDW Corp/DE	CDW	188.23	133	25,084	0.05%	1.33%	0.00%	7.00%	0.00%
Trane Technologies PLC	TT	370.16	225	83,295	0.18%	0.91%	0.00%	14.00%	0.02%
Interpublic Group of Cos Inc/The	IPG	29.40	373	10,952	0.02%	4.49%	0.00%	8.50%	0.00%
International Flavors & Fragrances Inc	IFF	99.43	256	25,420	0.05%	1.61%	0.00%	0.50%	0.00%
Generac Holdings Inc	GNRC	165.55	60	9,958	0.02%	n/a	n/a	12.50%	0.00%
NXP Semiconductors NV	NXPI	234.50	255	59,735	0.13%	1.73%	0.00%	7.50%	0.01%
Kellanova	K	80.65	345	27,800	0.06%	2.83%	0.00%	3.00%	0.00%
Broadridge Financial Solutions Inc	BR	210.86	117	24,647	0.05%	1.67%	0.00%	9.50%	0.00%
Kimberly-Clark Corp	KMB	134.18	333	44,747	0.09%	3.64%	0.00%	7.50%	0.01%
Kimco Realty Corp	KIM	23.72	674	15,990	0.03%	4.22%	0.00%	18.00%	0.01%
Oracle Corp	ORCL	167.84	2,771	465,095	0.98%	0.95%	0.01%	10.00%	0.10%
Kroger Co/The	KR	55.77	723	40,349	0.08%	2.30%	0.00%	5.00%	0.00%
Lennar Corp	LEN	170.30	239	40,669	0.09%	1.17%	0.00%	6.00%	0.01%
Eli Lilly & Co	LLY	829.74	949	787,685	1.66%	0.63%	0.01%	28.50%	0.47%
Charter Communications Inc	CHTR	327.61	143	46,763	0.10%	n/a	n/a	6.50%	0.01%
Loews Corp	L	78.96	220	17,333	0.04%	0.32%	0.00%	14.50%	0.01%
Lowe's Cos Inc	LOW	261.83	567	148,535	0.31%	1.76%	0.01%	5.50%	0.02%
Hubbell Inc	HUBB	427.03	54	22,919	0.05%	1.24%	0.00%	9.00%	0.00%
IDEX Corp	IEX	214.64	76	16,253	0.03%	1.29%	0.00%	5.00%	0.00%
Marsh & McLennan Cos Inc	MMC	218.24	491	107,182	0.23%	1.49%	0.00%	12.00%	0.03%
Masco Corp	MAS	79.91	216	17,240	0.04%	1.45%	0.00%	9.50%	0.00%
S&P Global Inc	SPGI	480.36	318	152,514	0.32%	0.76%	0.00%	8.00%	0.03%
Medtronic PLC	MDT	89.25	1,282	114,460	0.24%	3.14%	0.01%	6.50%	0.02%
Viatris Inc	VTRS	11.60	1,194	13,846	0.03%	4.14%	0.00%	-1.50%	0.00%
CVS Health Corp	CVS	56.46	1,258	71,025	0.15%	4.71%	0.01%	2.50%	0.00%
DuPont de Nemours Inc	DD	82.99	417	34,648	0.07%	1.83%	0.00%	9.00%	0.01%
Micron Technology Inc	MU	99.65	1,109	110,486	0.23%	0.46%	0.00%	24.00%	0.06%
Motorola Solutions Inc	MSI	449.35	167	74,970	0.16%	0.87%	0.00%	10.00%	0.02%
Cboe Global Markets Inc	CBOE	213.57	105	22,347	0.05%	1.18%	0.00%	14.00%	0.01%
Newmont Corp	NEM	45.44	1,138	51,731	0.11%	2.20%	0.00%	13.00%	0.01%
NIKE Inc	NKE	77.13	1,191	91,831	0.19%	1.92%	0.00%	10.50%	0.02%
NiSource Inc	NI	35.16	467	16,412	0.03%	3.01%	0.00%	9.50%	0.00%
Norfolk Southern Corp	NSC	250.43	226	56,657	0.12%	2.16%	0.00%	9.50%	0.01%
Principal Financial Group Inc	PFG	82.40	229	18,847	0.04%	3.54%	0.00%	4.00%	0.00%
Eversource Energy	ES	65.85	357	23,534	0.05%	4.34%	0.00%	6.00%	0.00%
Northrop Grumman Corp	NOC	509.02	146	74,162	0.16%	1.62%	0.00%	8.00%	0.01%
Wells Fargo & Co	WFC	64.92	3,329	216,151	0.45%	2.46%	0.01%	9.50%	0.04%
Nucor Corp	NUE	141.84	237	Excl.	0.00%	1.52%	0.00%		n/a
Occidental Petroleum Corp	OXY	50.11	916	45,911	0.10%	1.76%	0.00%	6.00%	0.01%
Omnicom Group Inc	OMC	101.00	195	19,704	0.04%	2.77%	0.00%	7.00%	0.00%
ONEOK Inc	OKE	96.88	584	56,596	0.12%	4.09%	0.00%	12.00%	0.01%
Raymond James Financial Inc	RJF	148.22	206	30,525	0.06%	1.21%	0.00%	10.00%	0.01%
PG&E Corp	PCG	20.22	2,137	43,219	0.09%	0.20%	0.00%	9.00%	0.01%
Parker-Hannifin Corp	PH	634.07	129	81,586	0.17%	1.03%	0.00%	12.50%	0.02%
Rollins Inc	ROL	47.14	484	22,830	0.05%	1.40%	0.00%	9.00%	0.00%
PPL Corp	PPL	32.56	738	24,022	0.05%	3.16%	0.00%	7.50%	0.00%
ConocoPhillips	COP	109.54	1,151	126,071	0.26%	2.85%	0.01%	4.00%	0.01%
PulteGroup Inc	PHM	129.53	205	26,564	0.06%	0.62%	0.00%	8.00%	0.00%
Pinnacle West Capital Corp	PNW	87.81	114	9,976	0.02%	4.08%	0.00%	4.50%	0.00%
PNC Financial Services Group Inc/The	PNC	188.27	397	74,837	0.16%	3.40%	0.01%	11.50%	0.02%
PPG Industries Inc	PPG	124.51	232	28,886	0.06%	2.18%	0.00%	7.00%	0.00%
Progressive Corp/The	PGR	242.83	586	142,217	0.30%	0.16%	0.00%	22.50%	0.07%
Veralto Corp	VLTO	102.19	247	25,272	0.05%	0.35%	0.00%	6.00%	0.00%
Public Service Enterprise Group Inc	PEG	89.41	498	44,541	0.09%	2.68%	0.00%	5.00%	0.00%
Cooper Cos Inc/The	COO	104.68	199	20,848	0.04%	n/a	n/a	7.50%	0.00%
Edison International	EIX	82.40	387	31,901	0.07%	3.79%	0.00%	6.50%	0.00%
Schlumberger NV	SLB	40.07	1,412	56,585	0.12%	2.75%	0.00%	22.00%	0.03%
Charles Schwab Corp/The	SCHW	70.83	1,778	125,967	0.26%	1.41%	0.00%	10.50%	0.03%
Sherwin-Williams Co/The	SHW	358.77	252	90,357	0.19%	0.80%	0.00%	11.00%	0.02%
West Pharmaceutical Services Inc	WST	307.93	72	22,301	0.05%	0.27%	0.00%	7.50%	0.00%
J M Smucker Co/The	SJM	113.51	106	12,078	0.03%	3.81%	0.00%	7.00%	0.00%
Snap-on Inc	SNA	330.13	53	17,334	0.04%	2.25%	0.00%	5.50%	0.00%
AMETEK Inc	AME	183.34	231	42,408	0.09%	0.61%	0.00%	10.00%	0.01%
Uber Technologies Inc	UBER	72.05	2,106	Excl.	0.00%	n/a	n/a		n/a
Southern Co/The	SO	91.03	1,095	99,644	0.21%	3.16%	0.01%	6.50%	0.01%
Truist Financial Corp	TFC	43.05	1,339	57,650	0.12%	4.83%	0.01%	1.50%	0.00%
Southwest Airlines Co	LUV	30.58	600	Excl.	0.00%	2.35%	0.00%		n/a
W R Berkley Corp	WRB	57.17	381	21,756	0.05%	0.56%	0.00%	13.00%	0.01%
Stanley Black & Decker Inc	SWK	92.94	154	14,328	0.03%	3.53%	0.00%	11.00%	0.00%
Public Storage	PSA	329.06	176	57,817	0.12%	3.65%	0.00%	7.00%	0.01%
Arista Networks Inc	ANET	386.44	314	121,401	0.26%	n/a	n/a	19.50%	0.05%
Sysco Corp	SYY	74.95	491	36,817	0.08%	2.72%	0.00%	13.50%	0.01%
Corteva Inc	CTVA	60.92	692	42,172	0.09%	1.12%	0.00%	9.50%	0.01%

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Name	Ticker	Price	Shares Outstanding	Market Capitalization	Weight in Index	Current Dividend Yield	Cap-Weighted Dividend Yield	Value Line Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Texas Instruments Inc	TXN	203.16	912	185,326	0.39%	2.68%	0.01%	3.00%	0.01%
Textron Inc	TXT	80.42	186	14,919	0.03%	0.10%	0.00%	13.00%	0.00%
Thermo Fisher Scientific Inc	TMO	546.32	382	208,692	0.44%	0.29%	0.00%	6.00%	0.03%
TJX Cos Inc/The	TJX	113.03	1,128	127,483	0.27%	1.33%	0.00%	17.00%	0.05%
Globe Life Inc	GL	105.60	90	9,485	0.02%	0.91%	0.00%	8.50%	0.00%
Johnson Controls International plc	JCI	75.55	668	50,468	0.11%	1.96%	0.00%	9.50%	0.01%
Ulta Beauty Inc	ULTA	368.98	47	17,384	0.04%	n/a	n/a	6.50%	0.00%
Union Pacific Corp	UNP	232.07	606	140,694	0.30%	2.31%	0.01%	8.00%	0.02%
Keysight Technologies Inc	KEYS	149.01	174	25,860	0.05%	n/a	n/a	8.00%	0.00%
UnitedHealth Group Inc	UNH	564.50	923	521,269	1.10%	1.49%	0.02%	12.00%	0.13%
Blackstone Inc	BX	167.75	720	120,793	0.25%	2.05%	0.01%	16.00%	0.04%
Marathon Oil Corp	MRO	27.70	559	15,495	0.03%	1.59%	0.00%	12.50%	0.00%
Ventas Inc	VTR	65.49	419	27,464	0.06%	2.75%	0.00%	23.00%	0.01%
Labcorp Holdings Inc	LH	228.27	84	19,092	0.04%	1.26%	0.00%	1.00%	0.00%
Vulcan Materials Co	VMC	273.93	132	36,175	0.08%	0.67%	0.00%	8.00%	0.01%
Weyerhaeuser Co	WY	31.16	727	22,640	0.05%	2.57%	0.00%	-2.00%	0.00%
Williams Cos Inc/The	WMB	52.37	1,219	63,835	0.13%	3.63%	0.00%	11.00%	0.01%
Constellation Energy Corp	CEG	262.96	315	Excl.	0.00%	0.54%	0.00%		n/a
WEC Energy Group Inc	WEC	95.53	316	30,195	0.06%	3.50%	0.00%	6.00%	0.00%
Adobe Inc	ADBE	478.08	440	210,451	0.44%	n/a	n/a	13.50%	0.06%
Vistra Corp	VST	124.96	344	Excl.	0.00%	0.71%	0.00%		n/a
AES Corp/The	AES	16.49	711	11,725	0.02%	4.18%	0.00%	14.00%	0.00%
Expeditors International of Washington Inc	EXPD	119.00	141	16,794	0.04%	1.23%	0.00%	-1.00%	0.00%
Amgen Inc	AMGN	320.16	538	172,097	0.36%	2.81%	0.01%	4.50%	0.02%
Apple Inc	AAPL	225.91	15,204	3,434,767	7.22%	0.44%	0.03%	8.00%	0.58%
Autodesk Inc	ADSK	283.80	215	61,017	0.13%	n/a	n/a	14.00%	0.02%
Cintas Corp	CTAS	205.81	403	83,003	0.17%	0.76%	0.00%	14.00%	0.02%
Comcast Corp	CMCSA	43.67	3,817	166,693	0.35%	2.84%	0.01%	7.50%	0.03%
Molson Coors Beverage Co	TAP	54.47	193	10,490	0.02%	3.23%	0.00%	11.50%	0.00%
KLA Corp	KLAC	666.23	134	89,115	0.19%	0.87%	0.00%	13.00%	0.02%
Marriott International Inc/MD	MAR	260.02	282	73,202	0.15%	0.97%	0.00%	11.00%	0.02%
Fiserv Inc	FI	197.90	569	112,589	0.24%	n/a	n/a	9.50%	0.02%
McCormick & Co Inc/MD	MKC	78.24	252	19,731	0.04%	2.15%	0.00%	4.50%	0.00%
PACCAR Inc	PCAR	104.28	524	54,674	0.11%	1.15%	0.00%	14.50%	0.02%
Costco Wholesale Corp	COST	874.18	443	387,326	0.81%	0.53%	0.00%	10.00%	0.08%
Stryker Corp	SYK	356.28	381	135,820	0.29%	0.90%	0.00%	9.50%	0.03%
Tyson Foods Inc	TSN	58.59	286	16,746	0.04%	3.35%	0.00%	6.00%	0.00%
Lamb Weston Holdings Inc	LW	77.69	143	11,078	0.02%	1.85%	0.00%	10.50%	0.00%
Applied Materials Inc	AMAT	181.58	824	149,695	0.31%	0.88%	0.00%	9.50%	0.03%
Cardinal Health Inc	CAH	108.52	242	26,258	0.06%	1.86%	0.00%	6.50%	0.00%
Cincinnati Financial Corp	CINF	140.83	156	22,014	0.05%	2.30%	0.00%	10.50%	0.00%
Paramount Global	PARA	10.94	626	6,849	0.01%	1.83%	0.00%	3.00%	0.00%
DR Horton Inc	DHI	169.00	326	55,101	0.12%	0.95%	0.00%	5.00%	0.01%
Electronic Arts Inc	EA	150.85	264	39,855	0.08%	0.50%	0.00%	14.00%	0.01%
Erie Indemnity Co	ERIE	448.84	46	20,731	0.04%	1.14%	0.00%	20.00%	0.01%
Fair Isaac Corp	FICO	1,993.11	25	48,869	0.10%	n/a	n/a	16.50%	0.02%
Fastenal Co	FAST	78.18	573	44,788	0.09%	2.00%	0.00%	9.00%	0.01%
M&T Bank Corp	MTB	194.68	167	Excl.	0.00%	2.77%	0.00%		n/a
Xcel Energy Inc	XEL	66.81	574	38,365	0.08%	3.28%	0.00%	6.00%	0.00%
Fifth Third Bancorp	FITB	43.68	677	29,563	0.06%	3.39%	0.00%	4.50%	0.00%
Gilead Sciences Inc	GILD	88.82	1,245	110,580	0.23%	3.47%	0.01%	2.50%	0.01%
Hasbro Inc	HAS	65.63	140	9,155	0.02%	4.27%	0.00%	8.50%	0.00%
Huntington Bancshares Inc/OH	HBAN	15.59	1,453	22,649	0.05%	3.98%	0.00%	7.50%	0.00%
Welltower Inc	WELL	134.88	623	83,988	0.18%	1.99%	0.00%	26.50%	0.05%
Biogen Inc	BIIB	174.00	146	25,355	0.05%	n/a	n/a	0.50%	0.00%
Northern Trust Corp	NTRS	100.52	198	19,925	0.04%	2.98%	0.00%	4.00%	0.00%
Packaging Corp of America	PKG	228.94	90	20,562	0.04%	2.18%	0.00%	9.00%	0.00%
Paychex Inc	PAYX	139.33	360	50,145	0.11%	2.81%	0.00%	8.00%	0.01%
QUALCOMM Inc	QCOM	162.77	1,114	181,326	0.38%	2.09%	0.01%	6.00%	0.02%
Ross Stores Inc	ROST	139.72	332	46,354	0.10%	1.05%	0.00%	14.00%	0.01%
IDEXX Laboratories Inc	IDXX	406.92	82	33,321	0.07%	n/a	n/a	10.50%	0.01%
Starbucks Corp	SBUX	97.70	1,133	110,714	0.23%	2.50%	0.01%	9.00%	0.02%
KeyCorp	KEY	17.25	991	17,099	0.04%	4.75%	0.00%	-2.00%	0.00%
Fox Corp	FOXA	42.00	225	9,435	0.02%	1.29%	0.00%	8.00%	0.00%
Fox Corp	FOX	38.96	236	Excl.	0.00%	1.39%	0.00%		n/a
State Street Corp	STT	92.80	293	Excl.	0.00%	3.28%	0.00%		n/a
Norwegian Cruise Line Holdings Ltd	NCLH	25.34	440	Excl.	0.00%	n/a	n/a		n/a
US Bancorp	USB	48.31	1,561	75,388	0.16%	4.14%	0.01%	4.00%	0.01%
A O Smith Corp	AOS	75.10	119	8,945	0.02%	1.81%	0.00%	9.00%	0.00%
Gen Digital Inc	GEN	29.11	616	17,938	0.04%	1.72%	0.00%	10.50%	0.00%
T Rowe Price Group Inc	TROW	109.86	223	24,455	0.05%	4.51%	0.00%	5.50%	0.00%
Waste Management Inc	WM	215.85	401	86,635	0.18%	1.39%	0.00%	6.00%	0.01%
Palantir Technologies Inc	PLTR	41.56	2,142	Excl.	0.00%	n/a	n/a		n/a
Constellation Brands Inc	STZ	232.34	182	42,178	0.09%	1.74%	0.00%	6.00%	0.01%
Invesco Ltd	IVZ	17.34	449	7,793	0.02%	4.73%	0.00%	10.00%	0.00%
Intuit Inc	INTU	610.30	280	171,062	0.36%	0.68%	0.00%	13.50%	0.05%
Morgan Stanley	MS	116.25	1,621	188,428	0.40%	3.18%	0.01%	9.50%	0.04%

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Microchip Technology Inc	MCHP	73.37	537	39,363	0.08%	2.48%	0.00%	6.00%	0.00%
Crowdstrike Holdings Inc	CRWD	296.87	233	Excl.	0.00%	n/a	n/a		n/a
Chubb Ltd	CB	282.44	403	113,851	0.24%	1.29%	0.00%	13.00%	0.03%
Hologic Inc	HOLX	80.87	232	18,784	0.04%	n/a	n/a	-2.00%	0.00%
Citizens Financial Group Inc	CFG	42.12	448	18,882	0.04%	3.99%	0.00%	7.50%	0.00%
Jabil Inc	JBL	123.09	113	13,890	0.03%	0.26%	0.00%	13.50%	0.00%
O'Reilly Automotive Inc	ORLY	1,153.14	58	66,889	0.14%	n/a	n/a	10.50%	0.01%
Allstate Corp/The	ALL	186.52	265	49,391	0.10%	1.97%	0.00%	30.00%	0.03%
Equity Residential	EQR	70.37	379	26,680	0.06%	3.84%	0.00%	-4.00%	0.00%
BorgWarner Inc	BWA	33.63	219	7,355	0.02%	1.31%	0.00%	5.50%	0.00%
Keurig Dr Pepper Inc	KDP	32.95	1,356	44,695	0.09%	2.79%	0.00%	10.00%	0.01%
Host Hotels & Resorts Inc	HST	17.24	702	12,110	0.03%	4.64%	0.00%	51.00%	0.01%
Incyte Corp	INCY	74.12	193	14,279	0.03%	n/a	n/a	18.50%	0.01%
Simon Property Group Inc	SPG	169.12	326	55,139	0.12%	4.85%	0.01%	3.50%	0.00%
Eastman Chemical Co	EMN	105.09	117	12,281	0.03%	3.08%	0.00%	3.50%	0.00%
AvalonBay Communities Inc	AVB	221.61	142	31,517	0.07%	3.07%	0.00%	5.50%	0.00%
Prudential Financial Inc	PRU	122.48	356	43,603	0.09%	4.25%	0.00%	4.00%	0.00%
United Parcel Service Inc	UPS	134.06	733	98,200	0.21%	4.86%	0.01%	3.50%	0.01%
Walgreens Boots Alliance Inc	WBA	9.46	865	8,179	0.02%	10.57%	0.00%	-7.00%	0.00%
STERIS PLC	STE	221.85	99	21,878	0.05%	1.03%	0.00%	8.00%	0.00%
McKesson Corp	MCK	500.59	130	64,915	0.14%	0.57%	0.00%	10.00%	0.01%
Lockheed Martin Corp	LMT	546.05	237	129,433	0.27%	2.42%	0.01%	9.50%	0.03%
Cencora Inc	COR	228.08	196	44,706	0.09%	0.89%	0.00%	6.50%	0.01%
Capital One Financial Corp	COF	162.79	382	62,106	0.13%	1.47%	0.00%	2.50%	0.00%
Campbell Soup Co	CPB	46.65	298	13,884	0.03%	3.17%	0.00%	5.00%	0.00%
Waters Corp	WAT	323.11	59	19,180	0.04%	n/a	n/a	6.50%	0.00%
Nordson Corp	NDSN	247.89	57	14,175	0.03%	1.26%	0.00%	10.00%	0.00%
Dollar Tree Inc	DLTR	64.64	215	13,897	0.03%	n/a	n/a	20.00%	0.01%
Darden Restaurants Inc	DRI	160.02	118	18,802	0.04%	3.50%	0.00%	10.00%	0.00%
Evergy Inc	EVRG	60.44	230	13,886	0.03%	4.25%	0.00%	7.50%	0.00%
Match Group Inc	MTCH	36.03	258	9,292	0.02%	n/a	n/a	12.00%	0.00%
Domino's Pizza Inc	DPZ	413.73	35	14,287	0.03%	1.46%	0.00%	12.50%	0.00%
NVR Inc	NVR	9,152.81	3	28,169	0.06%	n/a	n/a	1.50%	0.00%
NetApp Inc	NTAP	115.31	205	23,613	0.05%	1.80%	0.00%	7.50%	0.00%
Old Dominion Freight Line Inc	ODFL	201.32	214	43,142	0.09%	0.52%	0.00%	7.50%	0.01%
DaVita Inc	DVA	139.81	82	11,464	0.02%	n/a	n/a	9.50%	0.00%
Hartford Financial Services Group Inc/The	HIG	110.44	290	32,016	0.07%	1.88%	0.00%	7.00%	0.00%
Iron Mountain Inc	IRM	123.73	293	36,294	0.08%	2.31%	0.00%	5.50%	0.00%
Estee Lauder Cos Inc/The	EL	68.94	233	16,093	0.03%	2.03%	0.00%	3.50%	0.00%
Cadence Design Systems Inc	CDNS	276.12	274	75,729	0.16%	n/a	n/a	12.00%	0.02%
Tyler Technologies Inc	TYL	605.59	43	25,918	0.05%	n/a	n/a	8.00%	0.00%
Universal Health Services Inc	UHS	204.31	59	12,149	0.03%	0.39%	0.00%	9.00%	0.00%
Skyworks Solutions Inc	SWKS	87.58	160	Excl.	0.00%	3.20%	0.00%		n/a
Quest Diagnostics Inc	DGX	154.83	112	17,281	0.04%	1.94%	0.00%	3.00%	0.00%
Rockwell Automation Inc	ROK	266.71	113	30,263	0.06%	1.96%	0.00%	9.50%	0.01%
Kraft Heinz Co/The	KHC	33.46	1,209	40,459	0.09%	4.78%	0.00%	4.50%	0.00%
American Tower Corp	AMT	213.54	467	99,785	0.21%	3.03%	0.01%	11.00%	0.02%
Regeneron Pharmaceuticals Inc	REGN	838.20	108	90,586	0.19%	n/a	n/a	1.50%	0.00%
Amazon.com Inc	AMZN	186.40	10,496	1,956,374	4.11%	n/a	n/a	24.50%	1.01%
Jack Henry & Associates Inc	JKHY	181.93	73	13,266	0.03%	1.21%	0.00%	6.50%	0.00%
Ralph Lauren Corp	RL	197.93	40	7,929	0.02%	1.67%	0.00%	11.00%	0.00%
BXP Inc	BXP	80.56	158	12,723	0.03%	4.87%	0.00%	0.50%	0.00%
Amphenol Corp	APH	67.02	1,206	80,800	0.17%	0.98%	0.00%	13.50%	0.02%
Howmet Aerospace Inc	HWM	99.72	408	40,700	0.09%	0.32%	0.00%	12.00%	0.01%
Valero Energy Corp	VLO	129.76	317	41,080	0.09%	3.30%	0.00%	9.50%	0.01%
Synopsys Inc	SNPS	513.61	154	78,898	0.17%	n/a	n/a	12.50%	0.02%
CH Robinson Worldwide Inc	CHRW	103.04	117	12,085	0.03%	2.41%	0.00%	5.50%	0.00%
Accenture PLC	ACN	344.82	626	215,990	0.45%	1.72%	0.01%	12.50%	0.06%
TransDigm Group Inc	TDG	1,302.30	56	73,074	0.15%	n/a	n/a	22.00%	0.03%
Yum! Brands Inc	YUM	131.16	281	36,878	0.08%	2.04%	0.00%	10.00%	0.01%
Prologis Inc	PLD	112.94	926	104,572	0.22%	3.40%	0.01%	0.50%	0.00%
FirstEnergy Corp	FE	41.83	576	24,107	0.05%	4.06%	0.00%	5.50%	0.00%
VeriSign Inc	VRSN	176.84	96	16,994	0.04%	n/a	n/a	12.00%	0.00%
Quanta Services Inc	PWR	301.63	148	44,524	0.09%	0.12%	0.00%	16.50%	0.02%
Henry Schein Inc	HSIC	70.23	127	8,899	0.02%	n/a	n/a	8.50%	0.00%
Ameren Corp	AEE	87.11	267	23,216	0.05%	3.08%	0.00%	6.50%	0.00%
ANSYS Inc	ANSS	320.41	87	28,000	0.06%	n/a	n/a	9.50%	0.01%
FactSet Research Systems Inc	FDS	454.06	38	17,249	0.04%	0.92%	0.00%	11.00%	0.00%
NVIDIA Corp	NVDA	132.76	24,530	3,256,603	6.84%	0.03%	0.00%	41.00%	2.81%
Cognizant Technology Solutions Corp	CTSH	74.59	496	36,984	0.08%	1.61%	0.00%	8.00%	0.01%
Intuitive Surgical Inc	ISRG	503.84	356	179,457	0.38%	n/a	n/a	13.50%	0.05%
Take-Two Interactive Software Inc	TTWO	161.72	175	Excl.	0.00%	n/a	n/a		n/a
Republic Services Inc	RSG	198.00	313	62,004	0.13%	1.17%	0.00%	11.00%	0.01%
eBay Inc	EBAY	57.51	479	27,547	0.06%	1.88%	0.00%	9.50%	0.01%
Goldman Sachs Group Inc/The	GS	517.79	316	163,518	0.34%	2.32%	0.01%	7.50%	0.03%
SBA Communications Corp	SBAC	229.47	107	24,662	0.05%	1.71%	0.00%	16.50%	0.01%
Sempra	SRE	83.37	633	52,785	0.11%	2.97%	0.00%	7.00%	0.01%

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Moody's Corp	MCO	454.04	181	82,272	0.17%	0.75%	0.00%	9.00%	0.02%
ON Semiconductor Corp	ON	70.49	426	30,014	0.06%	n/a	n/a	8.00%	0.01%
Booking Holdings Inc	BKNG	4,676.25	33	154,768	0.33%	0.75%	0.00%	22.00%	0.07%
F5 Inc	FFIV	233.88	58	13,632	0.03%	n/a	n/a	10.00%	0.00%
Akamai Technologies Inc	AKAM	101.08	152	15,316	0.03%	n/a	n/a	6.00%	0.00%
Charles River Laboratories International Inc	CRL	178.58	52	9,220	0.02%	n/a	n/a	7.00%	0.00%
MarketAxess Holdings Inc	MKTX	289.42	38	10,926	0.02%	1.02%	0.00%	9.00%	0.00%
Devon Energy Corp	DVN	38.68	626	24,221	0.05%	2.28%	0.00%	3.00%	0.00%
Bio-Techne Corp	TECH	73.75	159	11,702	0.02%	0.43%	0.00%	10.00%	0.00%
Alphabet Inc	GOOGL	171.11	5,843	Excl.	0.00%	0.47%	0.00%		n/a
Teleflex Inc	TFX	201.06	46	9,338	0.02%	0.68%	0.00%	8.50%	0.00%
Allegion plc	ALLE	139.63	87	12,138	0.03%	1.38%	0.00%	8.50%	0.00%
Netflix Inc	NFLX	756.03	427	323,171	0.68%	n/a	n/a	16.50%	0.11%
Agilent Technologies Inc	A	130.31	287	37,442	0.08%	0.72%	0.00%	8.00%	0.01%
Warner Bros Discovery Inc	WBD	8.13	2,452	Excl.	0.00%	n/a	n/a		n/a
Elevance Health Inc	ELV	405.76	232	94,105	0.20%	1.61%	0.00%	11.00%	0.02%
Trimble Inc	TRMB	60.50	244	14,775	0.03%	n/a	n/a	5.50%	0.00%
CME Group Inc	CME	225.36	360	81,151	0.17%	2.04%	0.00%	5.50%	0.01%
Juniper Networks Inc	JNPR	38.90	331	12,879	0.03%	2.26%	0.00%	7.50%	0.00%
DTE Energy Co	DTE	124.22	207	25,704	0.05%	3.28%	0.00%	4.50%	0.00%
Nasdaq Inc	NDAQ	73.92	575	42,486	0.09%	1.30%	0.00%	3.50%	0.00%
Celanese Corp	CE	125.97	109	13,764	0.03%	2.22%	0.00%	4.50%	0.00%
Philip Morris International Inc	PM	132.70	1,555	206,326	0.43%	4.07%	0.02%	5.00%	0.02%
Salesforce Inc	CRM	291.37	956	278,550	0.59%	0.55%	0.00%	24.00%	0.14%
Ingersoll Rand Inc	IR	96.00	403	38,734	0.08%	0.08%	0.00%	10.50%	0.01%
Huntington Ingalls Industries Inc	HII	184.96	39	7,237	0.02%	2.92%	0.00%	10.00%	0.00%
Roper Technologies Inc	ROP	537.73	107	57,644	0.12%	0.56%	0.00%	9.00%	0.01%
MetLife Inc	MET	78.42	700	54,919	0.12%	2.78%	0.00%	7.50%	0.01%
Tapestry Inc	TPR	47.45	233	11,037	0.02%	2.95%	0.00%	9.00%	0.00%
CSX Corp	CSX	33.64	1,928	64,872	0.14%	1.43%	0.00%	9.00%	0.01%
Edwards Lifesciences Corp	EW	67.01	602	40,367	0.08%	n/a	n/a	10.00%	0.01%
Ameriprise Financial Inc	AMP	510.30	98	50,106	0.11%	1.16%	0.00%	10.00%	0.01%
Zebra Technologies Corp	ZBRA	381.97	52	19,702	0.04%	n/a	n/a	1.00%	0.00%
Zimmer Biomet Holdings Inc	ZBH	106.92	199	21,285	0.04%	0.90%	0.00%	6.50%	0.00%
CBRE Group Inc	CBRE	130.97	306	40,079	0.08%	n/a	n/a	5.00%	0.00%
Camden Property Trust	CPT	115.79	107	12,347	0.03%	3.56%	0.00%	-6.50%	0.00%
Mastercard Inc	MA	499.59	911	455,011	0.96%	0.53%	0.01%	14.50%	0.14%
CarMax Inc	KMX	72.38	155	11,213	0.02%	n/a	n/a	3.50%	0.00%
Intercontinental Exchange Inc	ICE	155.87	574	89,497	0.19%	1.15%	0.00%	7.50%	0.01%
Smurfit WestRock PLC	SW	51.50	520	Excl.	0.00%	2.35%	0.00%		n/a
Fidelity National Information Services Inc	FIS	89.73	546	48,954	0.10%	1.60%	0.00%	4.00%	0.00%
Chipotle Mexican Grill Inc	CMG	55.77	1,363	75,992	0.16%	n/a	n/a	20.00%	0.03%
Wynn Resorts Ltd	WYNN	96.02	111	10,657	0.02%	1.04%	0.00%	27.00%	0.01%
Live Nation Entertainment Inc	LYV	117.14	232	Excl.	0.00%	n/a	n/a		n/a
Assurant Inc	AIZ	191.70	52	9,929	0.02%	1.50%	0.00%	9.50%	0.00%
NRG Energy Inc	NRG	90.40	206	18,657	0.04%	1.80%	0.00%	11.00%	0.00%
Regions Financial Corp	RF	23.87	915	21,844	0.05%	4.19%	0.00%	4.50%	0.00%
Monster Beverage Corp	MNST	52.68	980	51,602	0.11%	n/a	n/a	12.00%	0.01%
Mosaic Co/The	MOS	26.76	319	8,527	0.02%	3.14%	0.00%	-9.50%	0.00%
Baker Hughes Co	BKR	38.08	990	37,681	0.08%	2.21%	0.00%	29.50%	0.02%
Expedia Group Inc	EXPE	156.31	125	19,485	0.04%	n/a	n/a	39.00%	0.02%
CF Industries Holdings Inc	CF	82.23	174	14,310	0.03%	2.43%	0.00%	-1.50%	0.00%
Leidos Holdings Inc	LDOS	183.16	133	24,440	0.05%	0.87%	0.00%	9.50%	0.00%
APA Corp	APA	23.60	370	8,730	0.02%	4.24%	0.00%	6.00%	0.00%
Alphabet Inc	GOOG	172.69	5,534	955,666	2.01%	0.46%	0.01%	13.50%	0.27%
First Solar Inc	FSLR	194.48	107	20,821	0.04%	n/a	n/a	34.50%	0.02%
Discover Financial Services	DFS	148.43	251	37,267	0.08%	1.89%	0.00%	4.00%	0.00%
Visa Inc	V	289.85	1,670	484,178	1.02%	0.81%	0.01%	13.50%	0.14%
Mid-America Apartment Communities Inc	MAA	151.34	117	17,689	0.04%	3.89%	0.00%	-15.00%	-0.01%
Xylem Inc/NY	XYL	121.78	243	29,586	0.06%	1.18%	0.00%	12.00%	0.01%
Marathon Petroleum Corp	MPC	145.47	335	48,686	0.10%	2.50%	0.00%	-6.50%	-0.01%
Advanced Micro Devices Inc	AMD	144.07	1,623	233,798	0.49%	n/a	n/a	17.00%	0.08%
Tractor Supply Co	TSCO	265.51	108	28,640	0.06%	1.66%	0.00%	11.50%	0.01%
ResMed Inc	RMD	242.47	147	35,594	0.07%	0.87%	0.00%	10.00%	0.01%
Mettler-Toledo International Inc	MTD	1,291.75	21	27,588	0.06%	n/a	n/a	8.50%	0.00%
Jacobs Solutions Inc	J	140.58	124	17,467	0.04%	0.83%	0.00%	11.00%	0.00%
Copart Inc	CPRT	51.47	963	49,585	0.10%	n/a	n/a	9.00%	0.01%
VICI Properties Inc	VICI	31.76	1,043	33,130	0.07%	5.45%	0.00%	10.50%	0.01%
Fortinet Inc	FTNT	78.66	765	60,168	0.13%	n/a	n/a	24.00%	0.03%
Albemarle Corp	ALB	94.73	118	11,134	0.02%	1.71%	0.00%	-3.50%	0.00%
Moderna Inc	MRNA	54.36	384	20,896	0.04%	n/a	n/a	-18.50%	-0.01%
Essex Property Trust Inc	ESS	283.86	64	18,243	0.04%	3.45%	0.00%	4.50%	0.00%
CoStar Group Inc	CSGP	72.79	410	29,841	0.06%	n/a	n/a	16.50%	0.01%
Realty Income Corp	O	59.37	871	51,703	0.11%	5.33%	0.01%	5.00%	0.01%
Westinghouse Air Brake Technologies Corp	WAB	187.98	172	32,312	0.07%	0.43%	0.00%	16.00%	0.01%
Pool Corp	POOL	361.64	38	13,762	0.03%	1.33%	0.00%	14.00%	0.00%
Western Digital Corp	WDC	65.31	346	22,578	0.05%	n/a	n/a	22.50%	0.01%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Price	[5] Shares Outstanding	[6] Market Capitalization	[7] Weight in Index	[8] Current Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
PepsiCo Inc	PEP	166.08	1,372	227,860	0.48%	3.26%	0.02%	7.50%	0.04%
TE Connectivity PLC	TEL	147.42	304	44,804	0.09%	1.76%	0.00%	10.50%	0.01%
Diamondback Energy Inc	FANG	176.77	296	52,270	0.11%	5.30%	0.01%	2.50%	0.00%
Palo Alto Networks Inc	PANW	360.33	327	Excl.	0.00%	n/a	n/a		n/a
ServiceNow Inc	NOW	932.99	206	192,196	0.40%	n/a	n/a	32.50%	0.13%
Church & Dwight Co Inc	CHD	99.91	245	24,459	0.05%	1.14%	0.00%	6.50%	0.00%
Federal Realty Investment Trust	FRT	110.84	85	9,417	0.02%	3.97%	0.00%	2.50%	0.00%
Amentum Holdings Inc	AMTM	29.74	243	Excl.	0.00%	n/a	n/a		n/a
MGM Resorts International	MGM	36.87	298	10,978	0.02%	n/a	n/a	25.00%	0.01%
American Electric Power Co Inc	AEP	98.75	532	52,547	0.11%	3.77%	0.00%	6.50%	0.01%
Invitation Homes Inc	INVH	31.41	613	19,242	0.04%	3.57%	0.00%	13.50%	0.01%
PTC Inc	PTC	185.33	120	22,265	0.05%	n/a	n/a	29.00%	0.01%
JB Hunt Transport Services Inc	JBHT	180.62	101	18,212	0.04%	0.95%	0.00%	7.50%	0.00%
Lam Research Corp	LRCX	74.35	1,287	95,665	0.20%	1.24%	0.00%	12.50%	0.03%
Mohawk Industries Inc	MHK	134.27	63	8,475	0.02%	n/a	n/a	1.00%	0.00%
Pentair PLC	PNR	99.12	165	16,378	0.03%	0.93%	0.00%	12.00%	0.00%
GE HealthCare Technologies Inc	GEHC	87.35	457	Excl.	0.00%	0.14%	0.00%		n/a
Vertex Pharmaceuticals Inc	VRTX	475.98	258	122,851	0.26%	n/a	n/a	11.00%	0.03%
Amcor PLC	AMCR	11.13	1,445	16,087	0.03%	4.58%	0.00%	11.50%	0.00%
Meta Platforms Inc	META	567.58	2,180	1,237,325	2.60%	0.35%	0.01%	17.50%	0.46%
T-Mobile US Inc	TMUS	223.16	1,160	258,974	0.54%	1.58%	0.01%	20.00%	0.11%
United Rentals Inc	URI	812.80	66	53,338	0.11%	0.80%	0.00%	19.00%	0.02%
Honeywell International Inc	HON	205.68	650	133,743	0.28%	2.20%	0.01%	10.00%	0.03%
Alexandria Real Estate Equities Inc	ARE	111.55	175	19,495	0.04%	4.66%	0.00%	9.50%	0.00%
Delta Air Lines Inc	DAL	57.22	645	Excl.	0.00%	1.05%	0.00%		n/a
Seagate Technology Holdings PLC	STX	100.37	212	21,231	0.04%	2.87%	0.00%	32.00%	0.01%
United Airlines Holdings Inc	UAL	78.26	329	Excl.	0.00%	n/a	n/a		n/a
News Corp	NWS	29.04	190	Excl.	0.00%	0.69%	0.00%		n/a
Centene Corp	CNC	62.26	505	31,433	0.07%	n/a	n/a	10.00%	0.01%
Martin Marietta Materials Inc	MLM	592.34	61	36,203	0.08%	0.53%	0.00%	11.00%	0.01%
Teradyne Inc	TER	106.21	163	17,331	0.04%	0.45%	0.00%	9.50%	0.00%
PayPal Holdings Inc	PYPL	79.30	1,003	79,501	0.17%	n/a	n/a	11.50%	0.02%
Tesla Inc	TSLA	249.85	3,210	802,033	1.69%	n/a	n/a	19.00%	0.32%
Blackrock Inc	BLK	981.03	148	145,318	0.31%	2.08%	0.01%	9.50%	0.03%
Arch Capital Group Ltd	ACGL	98.56	376	37,064	0.08%	n/a	n/a	17.00%	0.01%
KKR & Co Inc	KKR	138.24	887	122,680	0.26%	0.51%	0.00%	5.00%	0.01%
Dow Inc	DOW	49.38	700	34,571	0.07%	5.67%	0.00%	0.50%	0.00%
Everest Group Ltd	EG	355.61	43	15,389	0.03%	2.25%	0.00%	10.50%	0.00%
Teledyne Technologies Inc	TDY	455.32	47	21,219	0.04%	n/a	n/a	7.00%	0.00%
GE Vernova Inc	GEV	301.66	276	Excl.	0.00%	n/a	n/a		n/a
News Corp	NWSA	27.25	379	10,338	0.02%	0.73%	0.00%	14.50%	0.00%
Exelon Corp	EXC	39.30	1,005	Excl.	0.00%	3.87%	0.00%		n/a
Global Payments Inc	GPN	103.71	254	26,394	0.06%	0.96%	0.00%	13.50%	0.01%
Crown Castle Inc	CCI	107.49	435	46,715	0.10%	5.82%	0.01%	-0.50%	0.00%
Aptiv PLC	APTV	56.83	235	13,357	0.03%	n/a	n/a	28.50%	0.01%
Align Technology Inc	ALGN	205.03	75	15,315	0.03%	n/a	n/a	17.00%	0.01%
Kenvue Inc	KVUE	22.93	1,915	Excl.	0.00%	3.58%	0.00%		n/a
Targa Resources Corp	TRGP	166.96	219	36,578	0.08%	1.80%	0.00%	20.00%	0.02%
Bunge Global SA	BG	84.02	140	11,731	0.02%	3.24%	0.00%	0.00%	0.00%
Deckers Outdoor Corp	DECK	160.89	152	24,443	0.05%	n/a	n/a	16.00%	0.01%
LKQ Corp	LKQ	36.79	260	9,564	0.02%	3.26%	0.00%	7.00%	0.00%
Zoetis Inc	ZTS	178.78	453	80,996	0.17%	0.97%	0.00%	7.50%	0.01%
Digital Realty Trust Inc	DLR	178.23	327	58,354	0.12%	2.74%	0.00%	-5.00%	-0.01%
Equinix Inc	EQIX	908.08	96	87,619	0.18%	1.88%	0.00%	15.00%	0.03%
Las Vegas Sands Corp	LVS	51.85	725	Excl.	0.00%	1.54%	0.00%		n/a
Molina Healthcare Inc	MOH	321.22	57	18,374	0.04%	n/a	n/a	11.50%	0.00%

Notes:
[4] Source: Bloomberg Professional
[5] Source: Bloomberg Professional
[6] Equals [4] x [5]
[7] Equals [6] / Sum of Column [6]
[8] Source: Bloomberg Professional
[9] Equals [7] x [8]
[10] Source: Value Line, as of October 31, 2024
[11] Equals [7] x [10]

MARKET RISK PREMIUM DERIVED FROM S&P 500 - FERC METHODOLOGY

[1] Estimate of the S&P 500 Dividend Yield	1.53%
[2] Estimate of the S&P 500 Growth Rate	9.81%
[3] S&P 500 Estimated Required Market Return	11.41%

Notes:
[1] Sum of [9]
[2] Sum of [11]
[3] Equals ([1] x (1 + 0.5 x [2])) + [2]

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Price	[5] Shares Outstanding	[6] Market Capitalization	[7] Weight in Index	[8] Current Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	86.85	325	Excl.	Excl.	6.17%	n/a	-1.00%	n/a
American Express Co	AXP	270.08	704	190,257	0.50%	1.04%	0.01%	9.00%	0.05%
Verizon Communications Inc	VZ	42.13	4,210	177,352	0.47%	6.43%	0.03%	0.50%	0.00%
Broadcom Inc	AVGO	169.77	4,671	Excl.	Excl.	1.25%	n/a	30.00%	n/a
Boeing Co/The	BA	149.31	730	Excl.	Excl.	n/a	n/a		n/a
Solventum Corp	SOLV	72.58	173	Excl.	Excl.	n/a	n/a		n/a
Caterpillar Inc	CAT	376.20	485	182,419	0.48%	1.50%	0.01%	11.50%	0.06%
JPMorgan Chase & Co	JPM	221.92	2,815	624,780	1.66%	2.25%	0.04%	7.00%	0.12%
Chevron Corp	CVX	148.82	1,829	272,179	0.72%	4.38%	0.03%	5.00%	0.04%
Coca-Cola Co/The	KO	65.31	4,308	281,342	0.75%	2.97%	0.02%	7.00%	0.05%
AbbVie Inc	ABBV	203.87	1,766	360,105	0.96%	3.22%	0.03%	4.00%	0.04%
Walt Disney Co/The	DIS	96.20	1,814	Excl.	Excl.	0.94%	n/a	31.50%	n/a
Corpay Inc	CPAY	329.72	69	22,893	0.06%	n/a	n/a	15.50%	0.01%
Extra Space Storage Inc	EXR	163.30	212	34,608	0.09%	3.97%	0.00%	5.00%	0.00%
Exxon Mobil Corp	XOM	116.78	4,443	Excl.	Excl.	3.25%	n/a	-3.00%	n/a
Phillips 66	PSX	121.82	413	50,310	0.13%	3.78%	0.01%	0.50%	0.00%
General Electric Co	GE	171.78	1,082	Excl.	Excl.	0.65%	n/a	22.00%	n/a
HP Inc	HPQ	35.52	964	34,231	0.09%	3.10%	0.00%	12.50%	0.01%
Home Depot Inc/The	HD	393.75	993	391,109	1.04%	2.29%	0.02%	6.50%	0.07%
Monolithic Power Systems Inc	MPWR	759.30	49	37,017	0.10%	0.66%	0.00%	10.50%	0.01%
International Business Machines Corp	IBM	206.72	925	191,143	0.51%	3.23%	0.02%	3.00%	0.02%
Johnson & Johnson	JNJ	159.86	2,408	384,883	1.02%	3.10%	0.03%	3.00%	0.03%
Lululemon Athletica Inc	LULU	297.90	118	35,051	0.09%	n/a	n/a	13.00%	0.01%
McDonald's Corp	MCD	292.11	717	209,543	0.56%	2.42%	0.01%	8.00%	0.04%
Merck & Co Inc	MRK	102.32	2,535	259,362	0.69%	3.01%	0.02%	15.50%	0.11%
3M Co	MMM	128.47	545	Excl.	Excl.	2.18%	n/a	30.50%	n/a
American Water Works Co Inc	AWK	138.11	195	26,917	0.07%	2.22%	0.00%	4.50%	0.00%
Bank of America Corp	BAC	41.82	7,673	320,880	0.85%	2.49%	0.02%	7.00%	0.06%
Pfizer Inc	PFE	28.30	5,667	160,367	0.43%	5.94%	0.03%	2.50%	0.01%
Procter & Gamble Co/The	PG	165.18	2,355	389,006	1.03%	2.44%	0.03%	5.00%	0.05%
AT&T Inc	T	22.54	7,175	161,731	0.43%	4.92%	0.02%	4.00%	0.02%
Travelers Cos Inc/The	TRV	245.94	227	55,833	0.15%	1.71%	0.00%	12.00%	0.02%
RTX Corp	RTX	120.99	1,331	161,040	0.43%	2.08%	0.01%	12.00%	0.05%
Analog Devices Inc	ADI	223.11	496	110,773	0.29%	1.65%	0.00%	7.50%	0.02%
Walmart Inc	WMT	81.95	8,038	658,735	1.75%	1.01%	0.02%	9.50%	0.17%
Cisco Systems Inc	CSCO	54.77	3,986	218,314	0.58%	2.92%	0.02%	3.50%	0.02%
Intel Corp	INTC	21.52	4,276	Excl.	Excl.	n/a	n/a	-2.00%	n/a
General Motors Co	GM	50.76	1,100	55,815	0.15%	0.95%	0.00%	6.50%	0.01%
Microsoft Corp	MSFT	406.35	7,435	3,021,164	8.02%	0.82%	0.07%	14.00%	1.12%
Dollar General Corp	DG	80.04	220	Excl.	Excl.	2.95%	n/a	-0.50%	n/a
Cigna Group/The	CI	314.81	278	87,565	0.23%	1.78%	0.00%	12.00%	0.03%
Kinder Morgan Inc	KMI	24.51	2,222	54,452	0.14%	4.69%	0.01%	10.00%	0.01%
Citigroup Inc	C	64.17	1,908	122,423	0.32%	3.49%	0.01%	3.00%	0.01%
American International Group Inc	AIG	75.88	644	48,863	0.13%	2.11%	0.00%	13.00%	0.02%
Altria Group Inc	MO	54.46	1,695	92,300	0.24%	7.49%	0.02%	6.00%	0.01%
HCA Healthcare Inc	HCA	358.74	253	90,868	0.24%	0.74%	0.00%	10.50%	0.03%
International Paper Co	IP	55.54	347	19,293	0.05%	3.33%	0.00%	5.50%	0.00%
Hewlett Packard Enterprise Co	HPE	19.49	1,299	25,311	0.07%	2.67%	0.00%	7.50%	0.01%
Abbott Laboratories	ABT	113.37	1,734	196,635	0.52%	1.94%	0.01%	4.00%	0.02%
Aflac Inc	AFL	104.79	560	58,685	0.16%	1.91%	0.00%	7.50%	0.01%
Air Products and Chemicals Inc	APD	310.53	222	69,035	0.18%	2.28%	0.00%	10.50%	0.02%
Super Micro Computer Inc	SMCI	29.11	586	Excl.	Excl.	n/a	n/a	39.00%	n/a
Royal Caribbean Cruises Ltd	RCL	206.35	269	Excl.	Excl.	0.78%	n/a		n/a
Hess Corp	HES	134.48	308	41,435	0.11%	1.49%	0.00%	8.00%	0.01%
Archer-Daniels-Midland Co	ADM	55.21	478	26,398	0.07%	3.62%	0.00%	3.50%	0.00%
Automatic Data Processing Inc	ADP	289.24	408	117,960	0.31%	1.94%	0.01%	10.50%	0.03%
Verisk Analytics Inc	VRSK	274.72	141	38,793	0.10%	0.57%	0.00%	8.50%	0.01%
AutoZone Inc	AZO	3,009.00	17	50,865	0.13%	n/a	n/a	12.50%	0.02%
Linde PLC	LIN	456.15	476	217,199	0.58%	1.22%	0.01%	7.00%	0.04%
Avery Dennison Corp	AVY	207.03	80	16,634	0.04%	1.70%	0.00%	2.00%	0.00%
Enphase Energy Inc	ENPH	83.04	135	11,219	0.03%	n/a	n/a	14.00%	0.00%
MSCI Inc	MSCI	571.20	78	44,766	0.12%	1.12%	0.00%	9.50%	0.01%

STANDARD AND POOR'S 500 INDEX

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Ball Corp	BALL	59.25	298	17,682	0.05%	1.35%	0.00%	10.50%	0.00%
Axon Enterprise Inc	AXON	423.50	76	Excl.	Excl.	n/a	n/a	25.00%	n/a
Dayforce Inc	DAY	70.95	158	Excl.	Excl.	n/a	n/a		n/a
Carrier Global Corp	CARR	72.72	897	65,246	0.17%	1.05%	0.00%	12.00%	0.02%
Bank of New York Mellon Corp/The	BK	75.36	738	55,612	0.15%	2.49%	0.00%	15.00%	0.02%
Otis Worldwide Corp	OTIS	98.20	399	39,227	0.10%	1.59%	0.00%	11.00%	0.01%
Baxter International Inc	BAX	35.70	510	18,213	0.05%	3.25%	0.00%	3.00%	0.00%
Becton Dickinson & Co	BDX	233.59	289	67,517	0.18%	1.63%	0.00%	6.00%	0.01%
Berkshire Hathaway Inc	BRK/B	450.92	1,325	597,556	1.59%	n/a	n/a	9.00%	0.14%
Best Buy Co Inc	BBY	90.43	215	19,418	0.05%	4.16%	0.00%	1.00%	0.00%
Boston Scientific Corp	BSX	84.02	1,473	123,730	0.33%	n/a	n/a	13.00%	0.04%
Bristol-Myers Squibb Co	BMY	55.77	2,028	113,111	0.30%	4.30%	0.01%	1.00%	0.00%
Brown-Forman Corp	BF/B	44.03	304	13,365	0.04%	1.98%	0.00%	15.00%	0.01%
Coterra Energy Inc	CTRA	23.92	739	17,683	0.05%	3.51%	0.00%	4.50%	0.00%
Hilton Worldwide Holdings Inc	HLT	234.85	244	Excl.	Excl.	0.26%	n/a		n/a
Carnival Corp	CCL	22.00	1,154	Excl.	Excl.	n/a	n/a		n/a
Qorvo Inc	QRVO	71.26	95	6,736	0.02%	n/a	n/a	5.50%	0.00%
Builders FirstSource Inc	BLDR	171.40	116	19,960	0.05%	n/a	n/a	6.50%	0.00%
UDR Inc	UDR	42.19	330	13,921	0.04%	4.03%	0.00%	2.50%	0.00%
Clorox Co/The	CLX	158.55	124	19,625	0.05%	3.08%	0.00%	7.00%	0.00%
Paycom Software Inc	PAYC	209.03	58	Excl.	Excl.	0.72%	n/a	21.00%	n/a
CMS Energy Corp	CMS	69.61	299	20,798	0.06%	2.96%	0.00%	6.00%	0.00%
Colgate-Palmolive Co	CL	93.71	817	76,562	0.20%	2.13%	0.00%	11.50%	0.02%
EPAM Systems Inc	EPAM	188.65	57	Excl.	Excl.	n/a	n/a	20.50%	n/a
Conagra Brands Inc	CAG	28.94	477	13,812	0.04%	4.84%	0.00%	3.00%	0.00%
Airbnb Inc	ABNB	134.79	440	Excl.	Excl.	n/a	n/a	23.00%	n/a
Consolidated Edison Inc	ED	101.68	346	35,196	0.09%	3.27%	0.00%	6.00%	0.01%
Corning Inc	GLW	47.59	856	40,723	0.11%	2.35%	0.00%	17.50%	0.02%
GoDaddy Inc	GDDY	166.80	140	Excl.	Excl.	n/a	n/a	27.00%	n/a
Cummins Inc	CMI	328.98	137	45,086	0.12%	2.21%	0.00%	6.00%	0.01%
Caesars Entertainment Inc	CZR	40.05	212	Excl.	Excl.	n/a	n/a		n/a
Danaher Corp	DHR	245.66	722	177,434	0.47%	0.44%	0.00%	5.50%	0.03%
Target Corp	TGT	150.04	461	69,120	0.18%	2.99%	0.01%	9.50%	0.02%
Deere & Co	DE	404.69	274	110,723	0.29%	1.45%	0.00%	4.00%	0.01%
Dominion Energy Inc	D	59.53	839	49,942	0.13%	4.49%	0.01%	3.00%	0.00%
Dover Corp	DOV	189.33	137	25,975	0.07%	1.09%	0.00%	6.00%	0.00%
Alliant Energy Corp	LNT	60.00	256	15,390	0.04%	3.20%	0.00%	6.00%	0.00%
Steel Dynamics Inc	STLD	130.50	154	20,137	0.05%	1.41%	0.00%	2.00%	0.00%
Duke Energy Corp	DUK	115.27	771	88,873	0.24%	3.63%	0.01%	5.00%	0.01%
Regency Centers Corp	REG	71.44	181	12,966	0.03%	3.75%	0.00%	11.50%	0.00%
Eaton Corp PLC	ETN	331.58	395	131,040	0.35%	1.13%	0.00%	11.00%	0.04%
Ecolab Inc	ECL	245.73	283	69,581	0.18%	0.93%	0.00%	11.00%	0.02%
Revvity Inc	RVTY	118.59	123	Excl.	Excl.	0.24%	n/a	-2.50%	n/a
Dell Technologies Inc	DELL	123.63	334	41,277	0.11%	1.44%	0.00%	2.50%	0.00%
Emerson Electric Co	EMR	108.27	573	62,006	0.16%	1.94%	0.00%	7.00%	0.01%
EOG Resources Inc	EOG	121.96	569	69,346	0.18%	2.98%	0.01%	8.00%	0.01%
Aon PLC	AON	366.87	216	79,342	0.21%	0.74%	0.00%	12.50%	0.03%
Entergy Corp	ETR	154.78	214	33,097	0.09%	3.10%	0.00%	0.50%	0.00%
Equifax Inc	EFX	265.02	124	32,850	0.09%	0.59%	0.00%	7.00%	0.01%
EQT Corp	EQT	36.54	597	Excl.	Excl.	1.72%	n/a		n/a
IQVIA Holdings Inc	IQV	205.82	182	37,356	0.10%	n/a	n/a	11.00%	0.01%
Gartner Inc	IT	502.50	77	38,723	0.10%	n/a	n/a	8.00%	0.01%
FedEx Corp	FDX	273.85	244	66,908	0.18%	2.02%	0.00%	3.50%	0.01%
FMC Corp	FMC	64.99	125	8,113	0.02%	3.57%	0.00%	4.00%	0.00%
Brown & Brown Inc	BRO	104.64	286	29,923	0.08%	0.57%	0.00%	12.50%	0.01%
Ford Motor Co	F	10.29	3,903	Excl.	Excl.	5.83%	n/a	35.00%	n/a
NextEra Energy Inc	NEE	79.25	2,056	162,970	0.43%	2.60%	0.01%	8.00%	0.03%
Franklin Resources Inc	BEN	20.77	523	10,863	0.03%	5.97%	0.00%	4.00%	0.00%
Garmin Ltd	GRMN	198.35	192	38,088	0.10%	1.51%	0.00%	5.00%	0.01%
Freeport-McMoRan Inc	FCX	45.02	1,437	64,687	0.17%	1.33%	0.00%	11.00%	0.02%
Dexcom Inc	DXCM	70.48	391	Excl.	Excl.	n/a	n/a		n/a
General Dynamics Corp	GD	291.61	275	80,184	0.21%	1.95%	0.00%	10.00%	0.02%
General Mills Inc	GIS	68.02	555	37,762	0.10%	3.53%	0.00%	5.00%	0.01%
Genuine Parts Co	GPC	114.70	139	15,947	0.04%	3.49%	0.00%	8.50%	0.00%
Atmos Energy Corp	ATO	138.78	155	21,543	0.06%	2.32%	0.00%	7.00%	0.00%
WW Grainger Inc	GWW	1,109.23	49	54,020	0.14%	0.74%	0.00%	7.00%	0.01%
Halliburton Co	HAL	27.74	883	24,490	0.06%	2.45%	0.00%	18.00%	0.01%
L3Harris Technologies Inc	LHX	247.47	190	46,937	0.12%	1.87%	0.00%	11.50%	0.01%
Healthpeak Properties Inc	DOC	22.45	699	15,702	0.04%	5.35%	0.00%	7.00%	0.00%
Insulet Corp	PODD	231.53	70	Excl.	Excl.	n/a	n/a		n/a
Catalent Inc	CTLT	58.60	181	Excl.	Excl.	n/a	n/a	21.00%	n/a
Fortive Corp	FTV	71.43	347	24,783	0.07%	0.45%	0.00%	15.00%	0.01%
Hershey Co/The	HSY	177.58	148	26,224	0.07%	3.09%	0.00%	7.00%	0.00%
Synchrony Financial	SYF	55.14	389	Excl.	Excl.	1.81%	n/a	47.00%	n/a
Hormel Foods Corp	HRL	30.55	548	16,753	0.04%	3.70%	0.00%	7.50%	0.00%
Arthur J Gallagher & Co	AJG	281.20	219	61,695	0.16%	0.85%	0.00%	14.00%	0.02%
Mondelez International Inc	MDLZ	68.48	1,337	91,571	0.24%	2.75%	0.01%	7.50%	0.02%

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CenterPoint Energy Inc	CNP	29.53	652	19,245	0.05%	2.84%	0.00%	6.50%	0.00%
Humana Inc	HUM	257.83	120	31,046	0.08%	1.37%	0.00%	4.50%	0.00%
Willis Towers Watson PLC	WTW	302.19	101	30,438	0.08%	1.16%	0.00%	9.50%	0.01%
Illinois Tool Works Inc	ITW	261.13	295	77,112	0.20%	2.30%	0.00%	9.00%	0.02%
CDW Corp/DE	CDW	188.23	133	25,084	0.07%	1.33%	0.00%	7.00%	0.00%
Trane Technologies PLC	TT	370.16	225	83,295	0.22%	0.91%	0.00%	14.00%	0.03%
Interpublic Group of Cos Inc/The	IPG	29.40	373	10,952	0.03%	4.49%	0.00%	8.50%	0.00%
International Flavors & Fragrances Inc	IFF	99.43	256	25,420	0.07%	1.61%	0.00%	0.50%	0.00%
Generac Holdings Inc	GNRC	165.55	60	9,958	0.03%	n/a	n/a	12.50%	0.00%
NXP Semiconductors NV	NXPI	234.50	255	59,735	0.16%	1.73%	0.00%	7.50%	0.01%
Kellanova	K	80.65	345	27,800	0.07%	2.83%	0.00%	3.00%	0.00%
Broadridge Financial Solutions Inc	BR	210.86	117	24,647	0.07%	1.67%	0.00%	9.50%	0.01%
Kimberly-Clark Corp	KMB	134.18	333	44,747	0.12%	3.64%	0.00%	7.50%	0.01%
Kimco Realty Corp	KIM	23.72	674	15,990	0.04%	4.22%	0.00%	18.00%	0.01%
Oracle Corp	ORCL	167.84	2,771	465,095	1.23%	0.95%	0.01%	10.00%	0.12%
Kroger Co/The	KR	55.77	723	40,349	0.11%	2.30%	0.00%	5.00%	0.01%
Lennar Corp	LEN	170.30	239	40,669	0.11%	1.17%	0.00%	6.00%	0.01%
Eli Lilly & Co	LLY	829.74	949	Excl.	Excl.	0.63%	n/a	28.50%	n/a
Charter Communications Inc	CHTR	327.61	143	46,763	0.12%	n/a	n/a	6.50%	0.01%
Loews Corp	L	78.96	220	17,333	0.05%	0.32%	0.00%	14.50%	0.01%
Lowe's Cos Inc	LOW	261.83	567	148,535	0.39%	1.76%	0.01%	5.50%	0.02%
Hubbell Inc	HUBB	427.03	54	22,919	0.06%	1.24%	0.00%	9.00%	0.01%
IDEX Corp	IEX	214.64	76	16,253	0.04%	1.29%	0.00%	5.00%	0.00%
Marsh & McLennan Cos Inc	MMC	218.24	491	107,182	0.28%	1.49%	0.00%	12.00%	0.03%
Masco Corp	MAS	79.91	216	17,240	0.05%	1.45%	0.00%	9.50%	0.00%
S&P Global Inc	SPGI	480.36	318	152,514	0.40%	0.76%	0.00%	8.00%	0.03%
Medtronic PLC	MDT	89.25	1,282	114,460	0.30%	3.14%	0.01%	6.50%	0.02%
Viatris Inc	VTRS	11.60	1,194	Excl.	Excl.	4.14%	n/a	-1.50%	n/a
CVS Health Corp	CVS	56.46	1,258	71,025	0.19%	4.71%	0.01%	2.50%	0.00%
DuPont de Nemours Inc	DD	82.99	417	34,648	0.09%	1.83%	0.00%	9.00%	0.01%
Micron Technology Inc	MU	99.65	1,109	Excl.	Excl.	0.46%	n/a	24.00%	n/a
Motorola Solutions Inc	MSI	449.35	167	74,970	0.20%	0.87%	0.00%	10.00%	0.02%
Cboe Global Markets Inc	CBOE	213.57	105	22,347	0.06%	1.18%	0.00%	14.00%	0.01%
Newmont Corp	NEM	45.44	1,138	51,731	0.14%	2.20%	0.00%	13.00%	0.02%
NIKE Inc	NKE	77.13	1,191	91,831	0.24%	1.92%	0.00%	10.50%	0.03%
NiSource Inc	NI	35.16	467	16,412	0.04%	3.01%	0.00%	9.50%	0.00%
Norfolk Southern Corp	NSC	250.43	226	56,657	0.15%	2.16%	0.00%	9.50%	0.01%
Principal Financial Group Inc	PFG	82.40	229	18,847	0.05%	3.54%	0.00%	4.00%	0.00%
Eversource Energy	ES	65.85	357	23,534	0.06%	4.34%	0.00%	6.00%	0.00%
Northrop Grumman Corp	NOC	509.02	146	74,162	0.20%	1.62%	0.00%	8.00%	0.02%
Wells Fargo & Co	WFC	64.92	3,329	216,151	0.57%	2.46%	0.01%	9.50%	0.05%
Nucor Corp	NUE	141.84	237	Excl.	Excl.	1.52%	n/a		n/a
Occidental Petroleum Corp	OXY	50.11	916	45,911	0.12%	1.76%	0.00%	6.00%	0.01%
Omnicom Group Inc	OMC	101.00	195	19,704	0.05%	2.77%	0.00%	7.00%	0.00%
ONEOK Inc	OKE	96.88	584	56,596	0.15%	4.09%	0.01%	12.00%	0.02%
Raymond James Financial Inc	RJF	148.22	206	30,525	0.08%	1.21%	0.00%	10.00%	0.01%
PG&E Corp	PCG	20.22	2,137	43,219	0.11%	0.20%	0.00%	9.00%	0.01%
Parker-Hannifin Corp	PH	634.07	129	81,586	0.22%	1.03%	0.00%	12.50%	0.03%
Rollins Inc	ROL	47.14	484	22,830	0.06%	1.40%	0.00%	9.00%	0.01%
PPL Corp	PPL	32.56	738	24,022	0.06%	3.16%	0.00%	7.50%	0.00%
ConocoPhillips	COP	109.54	1,151	126,071	0.33%	2.85%	0.01%	4.00%	0.01%
PulteGroup Inc	PHM	129.53	205	26,564	0.07%	0.62%	0.00%	8.00%	0.01%
Pinnacle West Capital Corp	PNW	87.81	114	9,976	0.03%	4.08%	0.00%	4.50%	0.00%
PNC Financial Services Group Inc/The	PNC	188.27	397	74,837	0.20%	3.40%	0.01%	11.50%	0.02%
PPG Industries Inc	PPG	124.51	232	28,886	0.08%	2.18%	0.00%	7.00%	0.01%
Progressive Corp/The	PGR	242.83	586	Excl.	Excl.	0.16%	n/a	22.50%	n/a
Veralto Corp	VLTO	102.19	247	25,272	0.07%	0.35%	0.00%	6.00%	0.00%
Public Service Enterprise Group Inc	PEG	89.41	498	44,541	0.12%	2.68%	0.00%	5.00%	0.01%
Cooper Cos Inc/The	COO	104.68	199	20,848	0.06%	n/a	n/a	7.50%	0.00%
Edison International	EIX	82.40	387	31,901	0.08%	3.79%	0.00%	6.50%	0.01%
Schlumberger NV	SLB	40.07	1,412	Excl.	Excl.	2.75%	n/a	22.00%	n/a
Charles Schwab Corp/The	SCHW	70.83	1,778	125,967	0.33%	1.41%	0.00%	10.50%	0.04%
Sherwin-Williams Co/The	SHW	358.77	252	90,357	0.24%	0.80%	0.00%	11.00%	0.03%
West Pharmaceutical Services Inc	WST	307.93	72	22,301	0.06%	0.27%	0.00%	7.50%	0.00%
J M Smucker Co/The	SJM	113.51	106	12,078	0.03%	3.81%	0.00%	7.00%	0.00%
Snap-on Inc	SNA	330.13	53	17,334	0.05%	2.25%	0.00%	5.50%	0.00%
AMETEK Inc	AME	183.34	231	42,408	0.11%	0.61%	0.00%	10.00%	0.01%
Uber Technologies Inc	UBER	72.05	2,106	Excl.	Excl.	n/a	n/a		n/a
Southern Co/The	SO	91.03	1,095	99,644	0.26%	3.16%	0.01%	6.50%	0.02%
Truist Financial Corp	TFC	43.05	1,339	57,650	0.15%	4.83%	0.01%	1.50%	0.00%
Southwest Airlines Co	LUV	30.58	600	Excl.	Excl.	2.35%	n/a		n/a
W R Berkley Corp	WRB	57.17	381	21,756	0.06%	0.56%	0.00%	13.00%	0.01%
Stanley Black & Decker Inc	SWK	92.94	154	14,328	0.04%	3.53%	0.00%	11.00%	0.00%
Public Storage	PSA	329.06	176	57,817	0.15%	3.65%	0.01%	7.00%	0.01%
Arista Networks Inc	ANET	386.44	314	121,401	0.32%	n/a	n/a	19.50%	0.06%
Sysco Corp	SYY	74.95	491	36,817	0.10%	2.72%	0.00%	13.50%	0.01%
Corteva Inc	CTVA	60.92	692	42,172	0.11%	1.12%	0.00%	9.50%	0.01%

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Texas Instruments Inc	TXN	203.16	912	185,326	0.49%	2.68%	0.01%	3.00%	0.01%
Textron Inc	TXT	80.42	186	14,919	0.04%	0.10%	0.00%	13.00%	0.01%
Thermo Fisher Scientific Inc	TMO	546.32	382	208,692	0.55%	0.29%	0.00%	6.00%	0.03%
TJX Cos Inc/The	TJX	113.03	1,128	127,483	0.34%	1.33%	0.00%	17.00%	0.06%
Globe Life Inc	GL	105.60	90	9,485	0.03%	0.91%	0.00%	8.50%	0.00%
Johnson Controls International plc	JCI	75.55	668	50,468	0.13%	1.96%	0.00%	9.50%	0.01%
Ulta Beauty Inc	ULTA	368.98	47	17,384	0.05%	n/a	n/a	6.50%	0.00%
Union Pacific Corp	UNP	232.07	606	140,694	0.37%	2.31%	0.01%	8.00%	0.03%
Keysight Technologies Inc	KEYS	149.01	174	25,860	0.07%	n/a	n/a	8.00%	0.01%
UnitedHealth Group Inc	UNH	564.50	923	521,269	1.38%	1.49%	0.02%	12.00%	0.17%
Blackstone Inc	BX	167.75	720	120,793	0.32%	2.05%	0.01%	16.00%	0.05%
Marathon Oil Corp	MRO	27.70	559	15,495	0.04%	1.59%	0.00%	12.50%	0.01%
Ventas Inc	VTR	65.49	419	Excl.	Excl.	2.75%	n/a	23.00%	n/a
Labcorp Holdings Inc	LH	228.27	84	19,092	0.05%	1.26%	0.00%	1.00%	0.00%
Vulcan Materials Co	VMC	273.93	132	36,175	0.10%	0.67%	0.00%	8.00%	0.01%
Weyerhaeuser Co	WY	31.16	727	Excl.	Excl.	2.57%	n/a	-2.00%	n/a
Williams Cos Inc/The	WMB	52.37	1,219	63,835	0.17%	3.63%	0.01%	11.00%	0.02%
Constellation Energy Corp	CEG	262.96	315	Excl.	Excl.	0.54%	n/a		n/a
WEC Energy Group Inc	WEC	95.53	316	30,195	0.08%	3.50%	0.00%	6.00%	0.00%
Adobe Inc	ADBE	478.08	440	210,451	0.56%	n/a	n/a	13.50%	0.08%
Vistra Corp	VST	124.96	344	Excl.	Excl.	0.71%	n/a		n/a
AES Corp/The	AES	16.49	711	11,725	0.03%	4.18%	0.00%	14.00%	0.00%
Expeditors International of Washington Inc	EXPD	119.00	141	Excl.	Excl.	1.23%	n/a	-1.00%	n/a
Amgen Inc	AMGN	320.16	538	172,097	0.46%	2.81%	0.01%	4.50%	0.02%
Apple Inc	AAPL	225.91	15,204	3,434,767	9.11%	0.44%	0.04%	8.00%	0.73%
Autodesk Inc	ADSK	283.80	215	61,017	0.16%	n/a	n/a	14.00%	0.02%
Cintas Corp	CTAS	205.81	403	83,003	0.22%	0.76%	0.00%	14.00%	0.03%
Comcast Corp	CMCSA	43.67	3,817	166,693	0.44%	2.84%	0.01%	7.50%	0.03%
Molson Coors Beverage Co	TAP	54.47	193	10,490	0.03%	3.23%	0.00%	11.50%	0.00%
KLA Corp	KLAC	666.23	134	89,115	0.24%	0.87%	0.00%	13.00%	0.03%
Marriott International Inc/MD	MAR	260.02	282	73,202	0.19%	0.97%	0.00%	11.00%	0.02%
Fiserv Inc	FI	197.90	569	112,589	0.30%	n/a	n/a	9.50%	0.03%
McCormick & Co Inc/MD	MKC	78.24	252	19,731	0.05%	2.15%	0.00%	4.50%	0.00%
PACCAR Inc	PCAR	104.28	524	54,674	0.15%	1.15%	0.00%	14.50%	0.02%
Costco Wholesale Corp	COST	874.18	443	387,326	1.03%	0.53%	0.01%	10.00%	0.10%
Stryker Corp	SYK	356.28	381	135,820	0.36%	0.90%	0.00%	9.50%	0.03%
Tyson Foods Inc	TSN	58.59	286	16,746	0.04%	3.35%	0.00%	6.00%	0.00%
Lamb Weston Holdings Inc	LW	77.69	143	11,078	0.03%	1.85%	0.00%	10.50%	0.00%
Applied Materials Inc	AMAT	181.58	824	149,695	0.40%	0.88%	0.00%	9.50%	0.04%
Cardinal Health Inc	CAH	108.52	242	26,258	0.07%	1.86%	0.00%	6.50%	0.00%
Cincinnati Financial Corp	CINF	140.83	156	22,014	0.06%	2.30%	0.00%	10.50%	0.01%
Paramount Global	PARA	10.94	626	6,849	0.02%	1.83%	0.00%	3.00%	0.00%
DR Horton Inc	DHI	169.00	326	55,101	0.15%	0.95%	0.00%	5.00%	0.01%
Electronic Arts Inc	EA	150.85	264	39,855	0.11%	0.50%	0.00%	14.00%	0.01%
Erie Indemnity Co	ERIE	448.84	46	20,731	0.06%	1.14%	0.00%	20.00%	0.01%
Fair Isaac Corp	FICO	1,993.11	25	48,869	0.13%	n/a	n/a	16.50%	0.02%
Fastenal Co	FAST	78.18	573	44,788	0.12%	2.00%	0.00%	9.00%	0.01%
M&T Bank Corp	MTB	194.68	167	Excl.	Excl.	2.77%	n/a		n/a
Xcel Energy Inc	XEL	66.81	574	38,365	0.10%	3.28%	0.00%	6.00%	0.01%
Fifth Third Bancorp	FITB	43.68	677	29,563	0.08%	3.39%	0.00%	4.50%	0.00%
Gilead Sciences Inc	GILD	88.82	1,245	110,580	0.29%	3.47%	0.01%	2.50%	0.01%
Hasbro Inc	HAS	65.63	140	9,155	0.02%	4.27%	0.00%	8.50%	0.00%
Huntington Bancshares Inc/OH	HBAN	15.59	1,453	22,649	0.06%	3.98%	0.00%	7.50%	0.00%
Welltower Inc	WELL	134.88	623	Excl.	Excl.	1.99%	n/a	26.50%	n/a
Biogen Inc	BIIB	174.00	146	25,355	0.07%	n/a	n/a	0.50%	0.00%
Northern Trust Corp	NTRS	100.52	198	19,925	0.05%	2.98%	0.00%	4.00%	0.00%
Packaging Corp of America	PKG	228.94	90	20,562	0.05%	2.18%	0.00%	9.00%	0.00%
Paychex Inc	PAYX	139.33	360	50,145	0.13%	2.81%	0.00%	8.00%	0.01%
QUALCOMM Inc	QCOM	162.77	1,114	181,326	0.48%	2.09%	0.01%	6.00%	0.03%
Ross Stores Inc	ROST	139.72	332	46,354	0.12%	1.05%	0.00%	14.00%	0.02%
IDEXX Laboratories Inc	IDXX	406.92	82	33,321	0.09%	n/a	n/a	10.50%	0.01%
Starbucks Corp	SBUX	97.70	1,133	110,714	0.29%	2.50%	0.01%	9.00%	0.03%
KeyCorp	KEY	17.25	991	Excl.	Excl.	4.75%	n/a	-2.00%	n/a
Fox Corp	FOXA	42.00	225	9,435	0.03%	1.29%	0.00%	8.00%	0.00%
Fox Corp	FOX	38.96	236	Excl.	Excl.	1.39%	n/a		n/a
State Street Corp	STT	92.80	293	Excl.	Excl.	3.28%	n/a		n/a
Norwegian Cruise Line Holdings Ltd	NCLH	25.34	440	Excl.	Excl.	n/a	n/a		n/a
US Bancorp	USB	48.31	1,561	75,388	0.20%	4.14%	0.01%	4.00%	0.01%
A O Smith Corp	AOS	75.10	119	8,945	0.02%	1.81%	0.00%	9.00%	0.00%
Gen Digital Inc	GEN	29.11	616	17,938	0.05%	1.72%	0.00%	10.50%	0.00%
T Rowe Price Group Inc	TROW	109.86	223	24,455	0.06%	4.51%	0.00%	5.50%	0.00%
Waste Management Inc	WM	215.85	401	86,635	0.23%	1.39%	0.00%	6.00%	0.01%
Palantir Technologies Inc	PLTR	41.56	2,142	Excl.	Excl.	n/a	n/a		n/a
Constellation Brands Inc	STZ	232.34	182	42,178	0.11%	1.74%	0.00%	6.00%	0.01%
Invesco Ltd	IVZ	17.34	449	7,793	0.02%	4.73%	0.00%	10.00%	0.00%
Intuit Inc	INTU	610.30	280	171,062	0.45%	0.68%	0.00%	13.50%	0.06%
Morgan Stanley	MS	116.25	1,621	188,428	0.50%	3.18%	0.02%	9.50%	0.05%

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Name	Ticker	[4] Price	[5] Shares Outstanding	[6] Market Capitalization	[7] Weight in Index	[8] Current Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Microchip Technology Inc	MCHP	73.37	537	39,363	0.10%	2.48%	0.00%	6.00%	0.01%
Crowdstrike Holdings Inc	CRWD	296.87	233	Excl.	Excl.	n/a	n/a		n/a
Chubb Ltd	CB	282.44	403	113,851	0.30%	1.29%	0.00%	13.00%	0.04%
Hologic Inc	HOLX	80.87	232	Excl.	Excl.	n/a	n/a	-2.00%	n/a
Citizens Financial Group Inc	CFG	42.12	448	18,882	0.05%	3.99%	0.00%	7.50%	0.00%
Jabil Inc	JBL	123.09	113	13,890	0.04%	0.26%	0.00%	13.50%	0.00%
O'Reilly Automotive Inc	ORLY	1,153.14	58	66,889	0.18%	n/a	n/a	10.50%	0.02%
Allstate Corp/The	ALL	186.52	265	Excl.	Excl.	1.97%	n/a	30.00%	n/a
Equity Residential	EQR	70.37	379	Excl.	Excl.	3.84%	n/a	-4.00%	n/a
BorgWarner Inc	BWA	33.63	219	7,355	0.02%	1.31%	0.00%	5.50%	0.00%
Keurig Dr Pepper Inc	KDP	32.95	1,356	44,695	0.12%	2.79%	0.00%	10.00%	0.01%
Host Hotels & Resorts Inc	HST	17.24	702	Excl.	Excl.	4.64%	n/a	51.00%	n/a
Incyte Corp	INCY	74.12	193	14,279	0.04%	n/a	n/a	18.50%	0.01%
Simon Property Group Inc	SPG	169.12	326	55,139	0.15%	4.85%	0.01%	3.50%	0.01%
Eastman Chemical Co	EMN	105.09	117	12,281	0.03%	3.08%	0.00%	3.50%	0.00%
AvalonBay Communities Inc	AVB	221.61	142	31,517	0.08%	3.07%	0.00%	5.50%	0.00%
Prudential Financial Inc	PRU	122.48	356	43,603	0.12%	4.25%	0.00%	4.00%	0.00%
United Parcel Service Inc	UPS	134.06	733	98,200	0.26%	4.86%	0.01%	3.50%	0.01%
Walgreens Boots Alliance Inc	WBA	9.46	865	Excl.	Excl.	10.57%	n/a	-7.00%	n/a
STERIS PLC	STE	221.85	99	21,878	0.06%	1.03%	0.00%	8.00%	0.00%
McKesson Corp	MCK	500.59	130	64,915	0.17%	0.57%	0.00%	10.00%	0.02%
Lockheed Martin Corp	LMT	546.05	237	129,433	0.34%	2.42%	0.01%	9.50%	0.03%
Cencora Inc	COR	228.08	196	44,706	0.12%	0.89%	0.00%	6.50%	0.01%
Capital One Financial Corp	COF	162.79	382	62,106	0.16%	1.47%	0.00%	2.50%	0.00%
Campbell Soup Co	CPB	46.65	298	13,884	0.04%	3.17%	0.00%	5.00%	0.00%
Waters Corp	WAT	323.11	59	19,180	0.05%	n/a	n/a	6.50%	0.00%
Nordson Corp	NDSN	247.89	57	14,175	0.04%	1.26%	0.00%	10.00%	0.00%
Dollar Tree Inc	DLTR	64.64	215	13,897	0.04%	n/a	n/a	20.00%	0.01%
Darden Restaurants Inc	DRI	160.02	118	18,802	0.05%	3.50%	0.00%	10.00%	0.00%
Evergy Inc	EVRG	60.44	230	13,886	0.04%	4.25%	0.00%	7.50%	0.00%
Match Group Inc	MTCH	36.03	258	9,292	0.02%	n/a	n/a	12.00%	0.00%
Domino's Pizza Inc	DPZ	413.73	35	14,287	0.04%	1.46%	0.00%	12.50%	0.00%
NVR Inc	NVR	9,152.81	3	28,169	0.07%	n/a	n/a	1.50%	0.00%
NetApp Inc	NTAP	115.31	205	23,613	0.06%	1.80%	0.00%	7.50%	0.00%
Old Dominion Freight Line Inc	ODFL	201.32	214	43,142	0.11%	0.52%	0.00%	7.50%	0.01%
DaVita Inc	DVA	139.81	82	11,464	0.03%	n/a	n/a	9.50%	0.00%
Hartford Financial Services Group Inc/The	HIG	110.44	290	32,016	0.08%	1.88%	0.00%	7.00%	0.01%
Iron Mountain Inc	IRM	123.73	293	36,294	0.10%	2.31%	0.00%	5.50%	0.01%
Estee Lauder Cos Inc/The	EL	68.94	233	16,093	0.04%	2.03%	0.00%	3.50%	0.00%
Cadence Design Systems Inc	CDNS	276.12	274	75,729	0.20%	n/a	n/a	12.00%	0.02%
Tyler Technologies Inc	TYL	605.59	43	25,918	0.07%	n/a	n/a	8.00%	0.01%
Universal Health Services Inc	UHS	204.31	59	12,149	0.03%	0.39%	0.00%	9.00%	0.00%
Skyworks Solutions Inc	SWKS	87.58	160	Excl.	Excl.	3.20%	n/a		n/a
Quest Diagnostics Inc	DGX	154.83	112	17,281	0.05%	1.94%	0.00%	3.00%	0.00%
Rockwell Automation Inc	ROK	266.71	113	30,263	0.08%	1.96%	0.00%	9.50%	0.01%
Kraft Heinz Co/The	KHC	33.46	1,209	40,459	0.11%	4.78%	0.01%	4.50%	0.00%
American Tower Corp	AMT	213.54	467	99,785	0.26%	3.03%	0.01%	11.00%	0.03%
Regeneron Pharmaceuticals Inc	REGN	838.20	108	90,586	0.24%	n/a	n/a	1.50%	0.00%
Amazon.com Inc	AMZN	186.40	10,496	Excl.	Excl.	n/a	n/a	24.50%	n/a
Jack Henry & Associates Inc	JKHY	181.93	73	13,266	0.04%	1.21%	0.00%	6.50%	0.00%
Ralph Lauren Corp	RL	197.93	40	7,929	0.02%	1.67%	0.00%	11.00%	0.00%
BXP Inc	BXP	80.56	158	12,723	0.03%	4.87%	0.00%	0.50%	0.00%
Amphenol Corp	APH	67.02	1,206	80,800	0.21%	0.98%	0.00%	13.50%	0.03%
Howmet Aerospace Inc	HWM	99.72	408	40,700	0.11%	0.32%	0.00%	12.00%	0.01%
Valero Energy Corp	VLO	129.76	317	41,080	0.11%	3.30%	0.00%	9.50%	0.01%
Synopsys Inc	SNPS	513.61	154	78,898	0.21%	n/a	n/a	12.50%	0.03%
CH Robinson Worldwide Inc	CHRW	103.04	117	12,085	0.03%	2.41%	0.00%	5.50%	0.00%
Accenture PLC	ACN	344.82	626	215,990	0.57%	1.72%	0.01%	12.50%	0.07%
TransDigm Group Inc	TDG	1,302.30	56	Excl.	Excl.	n/a	n/a	22.00%	n/a
Yum! Brands Inc	YUM	131.16	281	36,878	0.10%	2.04%	0.00%	10.00%	0.01%
Prologis Inc	PLD	112.94	926	104,572	0.28%	3.40%	0.01%	0.50%	0.00%
FirstEnergy Corp	FE	41.83	576	24,107	0.06%	4.06%	0.00%	5.50%	0.00%
VeriSign Inc	VRSN	176.84	96	16,994	0.05%	n/a	n/a	12.00%	0.01%
Quanta Services Inc	PWR	301.63	148	44,524	0.12%	0.12%	0.00%	16.50%	0.02%
Henry Schein Inc	HSIC	70.23	127	8,899	0.02%	n/a	n/a	8.50%	0.00%
Ameren Corp	AEE	87.11	267	23,216	0.06%	3.08%	0.00%	6.50%	0.00%
ANSYS Inc	ANSS	320.41	87	28,000	0.07%	n/a	n/a	9.50%	0.01%
FactSet Research Systems Inc	FDS	454.06	38	17,249	0.05%	0.92%	0.00%	11.00%	0.01%
NVIDIA Corp	NVDA	132.76	24,530	Excl.	Excl.	0.03%	n/a	41.00%	n/a
Cognizant Technology Solutions Corp	CTSH	74.59	496	36,984	0.10%	1.61%	0.00%	8.00%	0.01%
Intuitive Surgical Inc	ISRG	503.84	356	179,457	0.48%	n/a	n/a	13.50%	0.06%
Take-Two Interactive Software Inc	TTWO	161.72	175	Excl.	Excl.	n/a	n/a		n/a
Republic Services Inc	RSG	198.00	313	62,004	0.16%	1.17%	0.00%	11.00%	0.02%
eBay Inc	EBAY	57.51	479	27,547	0.07%	1.88%	0.00%	9.50%	0.01%
Goldman Sachs Group Inc/The	GS	517.79	316	163,518	0.43%	2.32%	0.01%	7.50%	0.03%
SBA Communications Corp	SBAC	229.47	107	24,662	0.07%	1.71%	0.00%	16.50%	0.01%
Sempra	SRE	83.37	633	52,785	0.14%	2.97%	0.00%	7.00%	0.01%

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		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Price	Shares Outstanding	Market Capitalization	Weight in Index	Current Dividend Yield	Cap-Weighted Dividend Yield	Value Line Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Moody's Corp	MCO	454.04	181	82,272	0.22%	0.75%	0.00%	9.00%	0.02%
ON Semiconductor Corp	ON	70.49	426	30,014	0.08%	n/a	n/a	8.00%	0.01%
Booking Holdings Inc	BKNG	4,676.25	33	Excl.	Excl.	0.75%	n/a	22.00%	n/a
F5 Inc	FFIV	233.88	58	13,632	0.04%	n/a	n/a	10.00%	0.00%
Akamai Technologies Inc	AKAM	101.08	152	15,316	0.04%	n/a	n/a	6.00%	0.00%
Charles River Laboratories International Inc	CRL	178.58	52	9,220	0.02%	n/a	n/a	7.00%	0.00%
MarketAxess Holdings Inc	MKTX	289.42	38	10,926	0.03%	1.02%	0.00%	9.00%	0.00%
Devon Energy Corp	DVN	38.68	626	24,221	0.06%	2.28%	0.00%	3.00%	0.00%
Bio-Techne Corp	TECH	73.75	159	11,702	0.03%	0.43%	0.00%	10.00%	0.00%
Alphabet Inc	GOOGL	171.11	5,843	Excl.	Excl.	0.47%	n/a		n/a
Teleflex Inc	TFX	201.06	46	9,338	0.02%	0.68%	0.00%	8.50%	0.00%
Allegion plc	ALLE	139.63	87	12,138	0.03%	1.38%	0.00%	8.50%	0.00%
Netflix Inc	NFLX	756.03	427	323,171	0.86%	n/a	n/a	16.50%	0.14%
Agilent Technologies Inc	A	130.31	287	37,442	0.10%	0.72%	0.00%	8.00%	0.01%
Warner Bros Discovery Inc	WBD	8.13	2,452	Excl.	Excl.	n/a	n/a		n/a
Elevance Health Inc	ELV	405.76	232	94,105	0.25%	1.61%	0.00%	11.00%	0.03%
Trimble Inc	TRMB	60.50	244	14,775	0.04%	n/a	n/a	5.50%	0.00%
CME Group Inc	CME	225.36	360	81,151	0.22%	2.04%	0.00%	5.50%	0.01%
Juniper Networks Inc	JNPR	38.90	331	12,879	0.03%	2.26%	0.00%	7.50%	0.00%
DTE Energy Co	DTE	124.22	207	25,704	0.07%	3.28%	0.00%	4.50%	0.00%
Nasdaq Inc	NDAQ	73.92	575	42,486	0.11%	1.30%	0.00%	3.50%	0.00%
Celanese Corp	CE	125.97	109	13,764	0.04%	2.22%	0.00%	4.50%	0.00%
Philip Morris International Inc	PM	132.70	1,555	206,326	0.55%	4.07%	0.02%	5.00%	0.03%
Salesforce Inc	CRM	291.37	956	Excl.	Excl.	0.55%	n/a	24.00%	n/a
Ingersoll Rand Inc	IR	96.00	403	38,734	0.10%	0.08%	0.00%	10.50%	0.01%
Huntington Ingalls Industries Inc	HII	184.96	39	7,237	0.02%	2.92%	0.00%	10.00%	0.00%
Roper Technologies Inc	ROP	537.73	107	57,644	0.15%	0.56%	0.00%	9.00%	0.01%
MetLife Inc	MET	78.42	700	54,919	0.15%	2.78%	0.00%	7.50%	0.01%
Tapestry Inc	TPR	47.45	233	11,037	0.03%	2.95%	0.00%	9.00%	0.00%
CSX Corp	CSX	33.64	1,928	64,872	0.17%	1.43%	0.00%	9.00%	0.02%
Edwards Lifesciences Corp	EW	67.01	602	40,367	0.11%	n/a	n/a	10.00%	0.01%
Ameriprise Financial Inc	AMP	510.30	98	50,106	0.13%	1.16%	0.00%	10.00%	0.01%
Zebra Technologies Corp	ZBRA	381.97	52	19,702	0.05%	n/a	n/a	1.00%	0.00%
Zimmer Biomet Holdings Inc	ZBH	106.92	199	21,285	0.06%	0.90%	0.00%	6.50%	0.00%
CBRE Group Inc	CBRE	130.97	306	40,079	0.11%	n/a	n/a	5.00%	0.01%
Camden Property Trust	CPT	115.79	107	Excl.	Excl.	3.56%	n/a	-6.50%	n/a
Mastercard Inc	MA	499.59	911	455,011	1.21%	0.53%	0.01%	14.50%	0.18%
CarMax Inc	KMX	72.38	155	11,213	0.03%	n/a	n/a	3.50%	0.00%
Intercontinental Exchange Inc	ICE	155.87	574	89,497	0.24%	1.15%	0.00%	7.50%	0.02%
Smurfit WestRock PLC	SW	51.50	520	Excl.	Excl.	2.35%	n/a		n/a
Fidelity National Information Services Inc	FIS	89.73	546	48,954	0.13%	1.60%	0.00%	4.00%	0.01%
Chipotle Mexican Grill Inc	CMG	55.77	1,363	75,992	0.20%	n/a	n/a	20.00%	0.04%
Wynn Resorts Ltd	WYNN	96.02	111	Excl.	Excl.	1.04%	n/a	27.00%	n/a
Live Nation Entertainment Inc	LYV	117.14	232	Excl.	Excl.	n/a	n/a		n/a
Assurant Inc	AIZ	191.70	52	9,929	0.03%	1.50%	0.00%	9.50%	0.00%
NRG Energy Inc	NRG	90.40	206	18,657	0.05%	1.80%	0.00%	11.00%	0.01%
Regions Financial Corp	RF	23.87	915	21,844	0.06%	4.19%	0.00%	4.50%	0.00%
Monster Beverage Corp	MNST	52.68	980	51,602	0.14%	n/a	n/a	12.00%	0.02%
Mosaic Co/The	MOS	26.76	319	Excl.	Excl.	3.14%	n/a	-9.50%	n/a
Baker Hughes Co	BKR	38.08	990	Excl.	Excl.	2.21%	n/a	29.50%	n/a
Expedia Group Inc	EXPE	156.31	125	Excl.	Excl.	n/a	n/a	39.00%	n/a
CF Industries Holdings Inc	CF	82.23	174	Excl.	Excl.	2.43%	n/a	-1.50%	n/a
Leidos Holdings Inc	LDOS	183.16	133	24,440	0.06%	0.87%	0.00%	9.50%	0.01%
APA Corp	APA	23.60	370	8,730	0.02%	4.24%	0.00%	6.00%	0.00%
Alphabet Inc	GOOG	172.69	5,534	955,666	2.54%	0.46%	0.01%	13.50%	0.34%
First Solar Inc	FSLR	194.48	107	Excl.	Excl.	n/a	n/a	34.50%	n/a
Discover Financial Services	DFS	148.43	251	37,267	0.10%	1.89%	0.00%	4.00%	0.00%
Visa Inc	V	289.85	1,670	484,178	1.28%	0.81%	0.01%	13.50%	0.17%
Mid-America Apartment Communities Inc	MAA	151.34	117	Excl.	Excl.	3.89%	n/a	-15.00%	n/a
Xylem Inc/NY	XYL	121.78	243	29,586	0.08%	1.18%	0.00%	12.00%	0.01%
Marathon Petroleum Corp	MPC	145.47	335	Excl.	Excl.	2.50%	n/a	-6.50%	n/a
Advanced Micro Devices Inc	AMD	144.07	1,623	233,798	0.62%	n/a	n/a	17.00%	0.11%
Tractor Supply Co	TSCO	265.51	108	28,640	0.08%	1.66%	0.00%	11.50%	0.01%
ResMed Inc	RMD	242.47	147	35,594	0.09%	0.87%	0.00%	10.00%	0.01%
Mettler-Toledo International Inc	MTD	1,291.75	21	27,588	0.07%	n/a	n/a	8.50%	0.01%
Jacobs Solutions Inc	J	140.58	124	17,467	0.05%	0.83%	0.00%	11.00%	0.01%
Copart Inc	CPRT	51.47	963	49,585	0.13%	n/a	n/a	9.00%	0.01%
VICI Properties Inc	VICI	31.76	1,043	33,130	0.09%	5.45%	0.00%	10.50%	0.01%
Fortinet Inc	FTNT	78.66	765	Excl.	Excl.	n/a	n/a	24.00%	n/a
Albemarle Corp	ALB	94.73	118	Excl.	Excl.	1.71%	n/a	-3.50%	n/a
Moderna Inc	MRNA	54.36	384	Excl.	Excl.	n/a	n/a	-18.50%	n/a
Essex Property Trust Inc	ESS	283.86	64	18,243	0.05%	3.45%	0.00%	4.50%	0.00%
CoStar Group Inc	CSGP	72.79	410	29,841	0.08%	n/a	n/a	16.50%	0.01%
Realty Income Corp	O	59.37	871	51,703	0.14%	5.33%	0.01%	5.00%	0.01%
Westinghouse Air Brake Technologies Corp	WAB	187.98	172	32,312	0.09%	0.43%	0.00%	16.00%	0.01%
Pool Corp	POOL	361.64	38	13,762	0.04%	1.33%	0.00%	14.00%	0.01%
Western Digital Corp	WDC	65.31	346	Excl.	Excl.	n/a	n/a	22.50%	n/a

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Price	[5] Shares Outstanding	[6] Market Capitalization	[7] Weight in Index	[8] Current Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
PepsiCo Inc	PEP	166.08	1,372	227,860	0.60%	3.26%	0.02%	7.50%	0.05%
TE Connectivity PLC	TEL	147.42	304	44,804	0.12%	1.76%	0.00%	10.50%	0.01%
Diamondback Energy Inc	FANG	176.77	296	52,270	0.14%	5.30%	0.01%	2.50%	0.00%
Palo Alto Networks Inc	PANW	360.33	327	Excl.	Excl.	n/a	n/a		n/a
ServiceNow Inc	NOW	932.99	206	Excl.	Excl.	n/a	n/a	32.50%	n/a
Church & Dwight Co Inc	CHD	99.91	245	24,459	0.06%	1.14%	0.00%	6.50%	0.00%
Federal Realty Investment Trust	FRT	110.84	85	9,417	0.02%	3.97%	0.00%	2.50%	0.00%
Amentum Holdings Inc	AMTM	29.74	243	Excl.	Excl.	n/a	n/a		n/a
MGM Resorts International	MGM	36.87	298	Excl.	Excl.	n/a	n/a	25.00%	n/a
American Electric Power Co Inc	AEP	98.75	532	52,547	0.14%	3.77%	0.01%	6.50%	0.01%
Invitation Homes Inc	INVH	31.41	613	19,242	0.05%	3.57%	0.00%	13.50%	0.01%
PTC Inc	PTC	185.33	120	Excl.	Excl.	n/a	n/a	29.00%	n/a
JB Hunt Transport Services Inc	JBHT	180.62	101	18,212	0.05%	0.95%	0.00%	7.50%	0.00%
Lam Research Corp	LRCX	74.35	1,287	95,665	0.25%	1.24%	0.00%	12.50%	0.03%
Mohawk Industries Inc	MHK	134.27	63	8,475	0.02%	n/a	n/a	1.00%	0.00%
Pentair PLC	PNR	99.12	165	16,378	0.04%	0.93%	0.00%	12.00%	0.01%
GE HealthCare Technologies Inc	GEHC	87.35	457	Excl.	Excl.	0.14%	n/a		n/a
Vertex Pharmaceuticals Inc	VRTX	475.98	258	122,851	0.33%	n/a	n/a	11.00%	0.04%
Amcor PLC	AMCR	11.13	1,445	16,087	0.04%	4.58%	0.00%	11.50%	0.00%
Meta Platforms Inc	META	567.58	2,180	1,237,325	3.28%	0.35%	0.01%	17.50%	0.57%
T-Mobile US Inc	TMUS	223.16	1,160	258,974	0.69%	1.58%	0.01%	20.00%	0.14%
United Rentals Inc	URI	812.80	66	53,338	0.14%	0.80%	0.00%	19.00%	0.03%
Honeywell International Inc	HON	205.68	650	133,743	0.35%	2.20%	0.01%	10.00%	0.04%
Alexandria Real Estate Equities Inc	ARE	111.55	175	19,495	0.05%	4.66%	0.00%	9.50%	0.00%
Delta Air Lines Inc	DAL	57.22	645	Excl.	Excl.	1.05%	n/a		n/a
Seagate Technology Holdings PLC	STX	100.37	212	Excl.	Excl.	2.87%	n/a	32.00%	n/a
United Airlines Holdings Inc	UAL	78.26	329	Excl.	Excl.	n/a	n/a		n/a
News Corp	NWS	29.04	190	Excl.	Excl.	0.69%	n/a		n/a
Centene Corp	CNC	62.26	505	31,433	0.08%	n/a	n/a	10.00%	0.01%
Martin Marietta Materials Inc	MLM	592.34	61	36,203	0.10%	0.53%	0.00%	11.00%	0.01%
Teradyne Inc	TER	106.21	163	17,331	0.05%	0.45%	0.00%	9.50%	0.00%
PayPal Holdings Inc	PYPL	79.30	1,003	79,501	0.21%	n/a	n/a	11.50%	0.02%
Tesla Inc	TSLA	249.85	3,210	802,033	2.13%	n/a	n/a	19.00%	0.40%
Blackrock Inc	BLK	981.03	148	145,318	0.39%	2.08%	0.01%	9.50%	0.04%
Arch Capital Group Ltd	ACGL	98.56	376	37,064	0.10%	n/a	n/a	17.00%	0.02%
KKR & Co Inc	KKR	138.24	887	122,680	0.33%	0.51%	0.00%	5.00%	0.02%
Dow Inc	DOW	49.38	700	34,571	0.09%	5.67%	0.01%	0.50%	0.00%
Everest Group Ltd	EG	355.61	43	15,389	0.04%	2.25%	0.00%	10.50%	0.00%
Teledyne Technologies Inc	TDY	455.32	47	21,219	0.06%	n/a	n/a	7.00%	0.00%
GE Vernova Inc	GEV	301.66	276	Excl.	Excl.	n/a	n/a		n/a
News Corp	NWSA	27.25	379	10,338	0.03%	0.73%	0.00%	14.50%	0.00%
Exelon Corp	EXC	39.30	1,005	Excl.	Excl.	3.87%	n/a		n/a
Global Payments Inc	GPN	103.71	254	26,394	0.07%	0.96%	0.00%	13.50%	0.01%
Crown Castle Inc	CCI	107.49	435	Excl.	Excl.	5.82%	n/a	-0.50%	n/a
Aptiv PLC	APTV	56.83	235	Excl.	Excl.	n/a	n/a	28.50%	n/a
Align Technology Inc	ALGN	205.03	75	15,315	0.04%	n/a	n/a	17.00%	0.01%
Kenvue Inc	KVUE	22.93	1,915	Excl.	Excl.	3.58%	n/a		n/a
Targa Resources Corp	TRGP	166.96	219	36,578	0.10%	1.80%	0.00%	20.00%	0.02%
Bunge Global SA	BG	84.02	140	11,731	0.03%	3.24%	0.00%	0.00%	0.00%
Deckers Outdoor Corp	DECK	160.89	152	24,443	0.06%	n/a	n/a	16.00%	0.01%
LKQ Corp	LKQ	36.79	260	9,564	0.03%	3.26%	0.00%	7.00%	0.00%
Zoetis Inc	ZTS	178.78	453	80,996	0.21%	0.97%	0.00%	7.50%	0.02%
Digital Realty Trust Inc	DLR	178.23	327	Excl.	Excl.	2.74%	n/a	-5.00%	n/a
Equinix Inc	EQIX	908.08	96	87,619	0.23%	1.88%	0.00%	15.00%	0.03%
Las Vegas Sands Corp	LVS	51.85	725	Excl.	Excl.	1.54%	n/a		n/a
Molina Healthcare Inc	MOH	321.22	57	18,374	0.05%	n/a	n/a	11.50%	0.01%

Notes:
[4] Source: Bloomberg Professional
[5] Source: Bloomberg Professional
[6] Equals [4] x [5]
[7] Equals [6] / Sum of Column [6]
[8] Source: Bloomberg Professional
[9] Equals [7] x [8]
[10] Source: Value Line, as of October 31, 2024
[11] Equals [7] x [10]

CAPITAL ASSET PRICING MODEL - CURRENT RISK-FREE RATE, VALUE LINE BETA, AND
MARKET RISK PREMIUM DERIVED FROM S&P 500 - ALL COMPANIES
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
Alliant Energy Corporation	LNT	4.30%	0.90	15.07%	10.76%	13.99%
Ameren Corporation	AEE	4.30%	0.90	15.07%	10.76%	13.99%
American Electric Power Company, In	AEP	4.30%	0.85	15.07%	10.76%	13.45%
Entergy Corporation	ETR	4.30%	1.00	15.07%	10.76%	15.07%
Evergy, Inc.	EVRG	4.30%	0.95	15.07%	10.76%	14.53%
IDACORP, Inc.	IDA	4.30%	0.85	15.07%	10.76%	13.45%
NextEra Energy, Inc.	NEE	4.30%	1.05	15.07%	10.76%	15.61%
NorthWestern Corporation	NWE	4.30%	1.00	15.07%	10.76%	15.07%
OGE Energy Corporation	OGE	4.30%	1.05	15.07%	10.76%	15.61%
Pinnacle West Capital Corporation	PNW	4.30%	0.95	15.07%	10.76%	14.53%
TXNM Energy, Inc.	TXNM	4.30%	0.90	15.07%	10.76%	13.99%
Portland General Electric Company	POR	4.30%	0.95	15.07%	10.76%	14.53%
PPL Corporation	PPL	4.30%	1.15	15.07%	10.76%	16.68%
Southern Company	SO	4.30%	0.95	15.07%	10.76%	14.53%
Xcel Energy Inc.	XEL	4.30%	0.85	15.07%	10.76%	13.45%
Median			0.95			14.53%
Mean			0.95			14.56%

Notes:
[1] Source: Bloomberg Professional, 30-day average as of October 31, 2024
[2] Source: Value Line Reports
[3] Source: Exhibit JCN-5, page 1
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE, VALUE LINE BETA, AND
MARKET RISK PREMIUM DERIVED FROM S&P 500 - ALL COMPANIES
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2025 - Q1 2026)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
Alliant Energy Corporation	LNT	4.20%	0.90	15.07%	10.87%	13.98%
Ameren Corporation	AEE	4.20%	0.90	15.07%	10.87%	13.98%
American Electric Power Company, In	AEP	4.20%	0.85	15.07%	10.87%	13.44%
Entergy Corporation	ETR	4.20%	1.00	15.07%	10.87%	15.07%
Evergy, Inc.	EVRG	4.20%	0.95	15.07%	10.87%	14.52%
IDACORP, Inc.	IDA	4.20%	0.85	15.07%	10.87%	13.44%
NextEra Energy, Inc.	NEE	4.20%	1.05	15.07%	10.87%	15.61%
NorthWestern Corporation	NWE	4.20%	1.00	15.07%	10.87%	15.07%
OGE Energy Corporation	OGE	4.20%	1.05	15.07%	10.87%	15.61%
Pinnacle West Capital Corporation	PNW	4.20%	0.95	15.07%	10.87%	14.52%
TXNM Energy, Inc.	TXNM	4.20%	0.90	15.07%	10.87%	13.98%
Portland General Electric Company	POR	4.20%	0.95	15.07%	10.87%	14.52%
PPL Corporation	PPL	4.20%	1.15	15.07%	10.87%	16.70%
Southern Company	SO	4.20%	0.95	15.07%	10.87%	14.52%
Xcel Energy Inc.	XEL	4.20%	0.85	15.07%	10.87%	13.44%
Median			0.95			14.52%
Mean			0.95			14.56%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 43, No. 11, November 1, 2024 at 2
[2] Source: Value Line Reports
[3] Source: Exhibit JCN-5, page 1
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE, VALUE LINE BETA, AND
MARKET RISK PREMIUM DERIVED FROM S&P 500 - ALL COMPANIES
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2026 - 2030)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
Alliant Energy Corporation	LNT	4.30%	0.90	15.07%	10.77%	13.99%
Ameren Corporation	AEE	4.30%	0.90	15.07%	10.77%	13.99%
American Electric Power Company, In	AEP	4.30%	0.85	15.07%	10.77%	13.45%
Entergy Corporation	ETR	4.30%	1.00	15.07%	10.77%	15.07%
Evergy, Inc.	EVRG	4.30%	0.95	15.07%	10.77%	14.53%
IDACORP, Inc.	IDA	4.30%	0.85	15.07%	10.77%	13.45%
NextEra Energy, Inc.	NEE	4.30%	1.05	15.07%	10.77%	15.61%
NorthWestern Corporation	NWE	4.30%	1.00	15.07%	10.77%	15.07%
OGE Energy Corporation	OGE	4.30%	1.05	15.07%	10.77%	15.61%
Pinnacle West Capital Corporation	PNW	4.30%	0.95	15.07%	10.77%	14.53%
TXNM Energy, Inc.	TXNM	4.30%	0.90	15.07%	10.77%	13.99%
Portland General Electric Company	POR	4.30%	0.95	15.07%	10.77%	14.53%
PPL Corporation	PPL	4.30%	1.15	15.07%	10.77%	16.68%
Southern Company	SO	4.30%	0.95	15.07%	10.77%	14.53%
Xcel Energy Inc.	XEL	4.30%	0.85	15.07%	10.77%	13.45%
Median			0.95			14.53%
Mean			0.95			14.56%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 43, No. 6, June 1, 2024 at 14
[2] Source: Value Line Reports
[3] Source: Exhibit JCN-5, page 1
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE, BLOOMBERG BETA, AND
MARKET RISK PREMIUM DERIVED FROM S&P 500 - ALL COMPANIES
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
Alliant Energy Corporation	LNT	4.30%	0.77	15.07%	10.76%	12.61%
Ameren Corporation	AEE	4.30%	0.73	15.07%	10.76%	12.17%
American Electric Power Company, In	AEP	4.30%	0.74	15.07%	10.76%	12.23%
Entergy Corporation	ETR	4.30%	0.84	15.07%	10.76%	13.32%
Evergy, Inc.	EVRG	4.30%	0.77	15.07%	10.76%	12.54%
IDACORP, Inc.	IDA	4.30%	0.77	15.07%	10.76%	12.54%
NextEra Energy, Inc.	NEE	4.30%	0.80	15.07%	10.76%	12.91%
NorthWestern Corporation	NWE	4.30%	0.86	15.07%	10.76%	13.53%
OGE Energy Corporation	OGE	4.30%	0.89	15.07%	10.76%	13.87%
Pinnacle West Capital Corporation	PNW	4.30%	0.80	15.07%	10.76%	12.92%
TXNM Energy, Inc.	TXNM	4.30%	0.80	15.07%	10.76%	12.95%
Portland General Electric Company	POR	4.30%	0.76	15.07%	10.76%	12.53%
PPL Corporation	PPL	4.30%	0.93	15.07%	10.76%	14.29%
Southern Company	SO	4.30%	0.76	15.07%	10.76%	12.52%
Xcel Energy Inc.	XEL	4.30%	0.71	15.07%	10.76%	11.98%
Median			0.77			12.61%
Mean			0.80			12.86%

Notes:
[1] Source: Bloomberg Professional, 30-day average as of October 31, 2024
[2] Source: Bloomberg Professional, as of September 30, 2024
[3] Source: Exhibit JCN-5, page 1
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE, BLOOMBERG BETA, AND
MARKET RISK PREMIUM DERIVED FROM S&P 500 - ALL COMPANIES
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2025 - Q1 2026)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
Alliant Energy Corporation	LNT	4.20%	0.77	15.07%	10.87%	12.58%
Ameren Corporation	AEE	4.20%	0.73	15.07%	10.87%	12.15%
American Electric Power Company, In	AEP	4.20%	0.74	15.07%	10.87%	12.21%
Entergy Corporation	ETR	4.20%	0.84	15.07%	10.87%	13.30%
Evergy, Inc.	EVRG	4.20%	0.77	15.07%	10.87%	12.52%
IDACORP, Inc.	IDA	4.20%	0.77	15.07%	10.87%	12.51%
NextEra Energy, Inc.	NEE	4.20%	0.80	15.07%	10.87%	12.89%
NorthWestern Corporation	NWE	4.20%	0.86	15.07%	10.87%	13.51%
OGE Energy Corporation	OGE	4.20%	0.89	15.07%	10.87%	13.86%
Pinnacle West Capital Corporation	PNW	4.20%	0.80	15.07%	10.87%	12.90%
TXNM Energy, Inc.	TXNM	4.20%	0.80	15.07%	10.87%	12.93%
Portland General Electric Company	POR	4.20%	0.76	15.07%	10.87%	12.51%
PPL Corporation	PPL	4.20%	0.93	15.07%	10.87%	14.28%
Southern Company	SO	4.20%	0.76	15.07%	10.87%	12.50%
Xcel Energy Inc.	XEL	4.20%	0.71	15.07%	10.87%	11.95%
Median			0.77			12.58%
Mean			0.80			12.84%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 43, No. 11, November 1, 2024 at 2
[2] Source: Bloomberg Professional, as of September 30, 2024
[3] Source: Exhibit JCN-5, page 1
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE, BLOOMBERG BETA, AND
MARKET RISK PREMIUM DERIVED FROM S&P 500 - ALL COMPANIES
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2026 - 2030)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
Alliant Energy Corporation	LNT	4.30%	0.77	15.07%	10.77%	12.61%
Ameren Corporation	AEE	4.30%	0.73	15.07%	10.77%	12.17%
American Electric Power Company, In	AEP	4.30%	0.74	15.07%	10.77%	12.23%
Entergy Corporation	ETR	4.30%	0.84	15.07%	10.77%	13.32%
Evergy, Inc.	EVRG	4.30%	0.77	15.07%	10.77%	12.54%
IDACORP, Inc.	IDA	4.30%	0.77	15.07%	10.77%	12.54%
NextEra Energy, Inc.	NEE	4.30%	0.80	15.07%	10.77%	12.91%
NorthWestern Corporation	NWE	4.30%	0.86	15.07%	10.77%	13.52%
OGE Energy Corporation	OGE	4.30%	0.89	15.07%	10.77%	13.87%
Pinnacle West Capital Corporation	PNW	4.30%	0.80	15.07%	10.77%	12.92%
TXNM Energy, Inc.	TXNM	4.30%	0.80	15.07%	10.77%	12.95%
Portland General Electric Company	POR	4.30%	0.76	15.07%	10.77%	12.53%
PPL Corporation	PPL	4.30%	0.93	15.07%	10.77%	14.29%
Southern Company	SO	4.30%	0.76	15.07%	10.77%	12.52%
Xcel Energy Inc.	XEL	4.30%	0.71	15.07%	10.77%	11.98%
Median			0.77			12.61%
Mean			0.80			12.86%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 43, No. 6, June 1, 2024 at 14
[2] Source: Bloomberg Professional, as of September 30, 2024
[3] Source: Exhibit JCN-5, page 1
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE, VALUE LINE BETA, AND
MARKET RISK PREMIUM DERIVED FROM S&P 500 - FERC METHODOLOGY
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
Alliant Energy Corporation	LNT	4.30%	0.90	11.41%	7.11%	10.70%
Ameren Corporation	AEE	4.30%	0.90	11.41%	7.11%	10.70%
American Electric Power Company, In	AEP	4.30%	0.85	11.41%	7.11%	10.34%
Entergy Corporation	ETR	4.30%	1.00	11.41%	7.11%	11.41%
Evergy, Inc.	EVRG	4.30%	0.95	11.41%	7.11%	11.05%
IDACORP, Inc.	IDA	4.30%	0.85	11.41%	7.11%	10.34%
NextEra Energy, Inc.	NEE	4.30%	1.05	11.41%	7.11%	11.76%
NorthWestern Corporation	NWE	4.30%	1.00	11.41%	7.11%	11.41%
OGE Energy Corporation	OGE	4.30%	1.05	11.41%	7.11%	11.76%
Pinnacle West Capital Corporation	PNW	4.30%	0.95	11.41%	7.11%	11.05%
TXNM Energy, Inc.	TXNM	4.30%	0.90	11.41%	7.11%	10.70%
Portland General Electric Company	POR	4.30%	0.95	11.41%	7.11%	11.05%
PPL Corporation	PPL	4.30%	1.15	11.41%	7.11%	12.47%
Southern Company	SO	4.30%	0.95	11.41%	7.11%	11.05%
Xcel Energy Inc.	XEL	4.30%	0.85	11.41%	7.11%	10.34%
Median			0.95			11.05%
Mean			0.95			11.08%

Notes:
[1] Source: Bloomberg Professional, 30-day average as of October 31, 2024
[2] Source: Value Line Reports
[3] Source: Exhibit JCN-5, page 8
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE, VALUE LINE BETA, AND
MARKET RISK PREMIUM DERIVED FROM S&P 500 - FERC METHODOLOGY
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2025 - Q1 2026)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
Alliant Energy Corporation	LNT	4.20%	0.90	11.41%	7.21%	10.69%
Ameren Corporation	AEE	4.20%	0.90	11.41%	7.21%	10.69%
American Electric Power Company, In	AEP	4.20%	0.85	11.41%	7.21%	10.33%
Entergy Corporation	ETR	4.20%	1.00	11.41%	7.21%	11.41%
Evergy, Inc.	EVRG	4.20%	0.95	11.41%	7.21%	11.05%
IDACORP, Inc.	IDA	4.20%	0.85	11.41%	7.21%	10.33%
NextEra Energy, Inc.	NEE	4.20%	1.05	11.41%	7.21%	11.77%
NorthWestern Corporation	NWE	4.20%	1.00	11.41%	7.21%	11.41%
OGE Energy Corporation	OGE	4.20%	1.05	11.41%	7.21%	11.77%
Pinnacle West Capital Corporation	PNW	4.20%	0.95	11.41%	7.21%	11.05%
TXNM Energy, Inc.	TXNM	4.20%	0.90	11.41%	7.21%	10.69%
Portland General Electric Company	POR	4.20%	0.95	11.41%	7.21%	11.05%
PPL Corporation	PPL	4.20%	1.15	11.41%	7.21%	12.49%
Southern Company	SO	4.20%	0.95	11.41%	7.21%	11.05%
Xcel Energy Inc.	XEL	4.20%	0.85	11.41%	7.21%	10.33%
Median			0.95			11.05%
Mean			0.95			11.07%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 43, No. 11, November 1, 2024 at 2
[2] Source: Value Line Reports
[3] Source: Exhibit JCN-5, page 8
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE, VALUE LINE BETA, AND
MARKET RISK PREMIUM DERIVED FROM S&P 500 - FERC METHODOLOGY
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2026 - 2030)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
Alliant Energy Corporation	LNT	4.30%	0.90	11.41%	7.11%	10.70%
Ameren Corporation	AEE	4.30%	0.90	11.41%	7.11%	10.70%
American Electric Power Company, In	AEP	4.30%	0.85	11.41%	7.11%	10.34%
Entergy Corporation	ETR	4.30%	1.00	11.41%	7.11%	11.41%
Evergy, Inc.	EVRG	4.30%	0.95	11.41%	7.11%	11.05%
IDACORP, Inc.	IDA	4.30%	0.85	11.41%	7.11%	10.34%
NextEra Energy, Inc.	NEE	4.30%	1.05	11.41%	7.11%	11.76%
NorthWestern Corporation	NWE	4.30%	1.00	11.41%	7.11%	11.41%
OGE Energy Corporation	OGE	4.30%	1.05	11.41%	7.11%	11.76%
Pinnacle West Capital Corporation	PNW	4.30%	0.95	11.41%	7.11%	11.05%
TXNM Energy, Inc.	TXNM	4.30%	0.90	11.41%	7.11%	10.70%
Portland General Electric Company	POR	4.30%	0.95	11.41%	7.11%	11.05%
PPL Corporation	PPL	4.30%	1.15	11.41%	7.11%	12.47%
Southern Company	SO	4.30%	0.95	11.41%	7.11%	11.05%
Xcel Energy Inc.	XEL	4.30%	0.85	11.41%	7.11%	10.34%
Median			0.95			11.05%
Mean			0.95			11.08%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 43, No. 6, June 1, 2024 at 14
[2] Source: Value Line Reports
[3] Source: Exhibit JCN-5, page 8
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE, BLOOMBERG BETA, AND
MARKET RISK PREMIUM DERIVED FROM S&P 500 - FERC METHODOLOGY
K = Rf + β (Rm − Rf)

Company	Ticker	[1] Current 30-day average of 30-year U.S. Treasury bond yield	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)
Alliant Energy Corporation	LNT	4.30%	0.77	11.41%	7.11%	9.79%
Ameren Corporation	AEE	4.30%	0.73	11.41%	7.11%	9.50%
American Electric Power Company, In	AEP	4.30%	0.74	11.41%	7.11%	9.54%
Entergy Corporation	ETR	4.30%	0.84	11.41%	7.11%	10.25%
Evergy, Inc.	EVRG	4.30%	0.77	11.41%	7.11%	9.74%
IDACORP, Inc.	IDA	4.30%	0.77	11.41%	7.11%	9.74%
NextEra Energy, Inc.	NEE	4.30%	0.80	11.41%	7.11%	9.99%
NorthWestern Corporation	NWE	4.30%	0.86	11.41%	7.11%	10.39%
OGE Energy Corporation	OGE	4.30%	0.89	11.41%	7.11%	10.62%
Pinnacle West Capital Corporation	PNW	4.30%	0.80	11.41%	7.11%	9.99%
TXNM Energy, Inc.	TXNM	4.30%	0.80	11.41%	7.11%	10.01%
Portland General Electric Company	POR	4.30%	0.76	11.41%	7.11%	9.74%
PPL Corporation	PPL	4.30%	0.93	11.41%	7.11%	10.89%
Southern Company	SO	4.30%	0.76	11.41%	7.11%	9.73%
Xcel Energy Inc.	XEL	4.30%	0.71	11.41%	7.11%	9.37%
Median			0.77			9.79%
Mean			0.80			9.95%

Notes:
[1] Source: Bloomberg Professional, 30-day average as of October 31, 2024
[2] Source: Bloomberg Professional, as of September 30, 2024
[3] Source: Exhibit JCN-5, page 8
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE, BLOOMBERG BETA, AND
MARKET RISK PREMIUM DERIVED FROM S&P 500 - FERC METHODOLOGY
K = Rf + β (Rm − Rf)

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (Q1 2025 - Q1 2026)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)
Alliant Energy Corporation	LNT	4.20%	0.77	11.41%	7.21%	9.76%
Ameren Corporation	AEE	4.20%	0.73	11.41%	7.21%	9.47%
American Electric Power Company, In	AEP	4.20%	0.74	11.41%	7.21%	9.51%
Entergy Corporation	ETR	4.20%	0.84	11.41%	7.21%	10.24%
Evergy, Inc.	EVRG	4.20%	0.77	11.41%	7.21%	9.72%
IDACORP, Inc.	IDA	4.20%	0.77	11.41%	7.21%	9.72%
NextEra Energy, Inc.	NEE	4.20%	0.80	11.41%	7.21%	9.97%
NorthWestern Corporation	NWE	4.20%	0.86	11.41%	7.21%	10.38%
OGE Energy Corporation	OGE	4.20%	0.89	11.41%	7.21%	10.61%
Pinnacle West Capital Corporation	PNW	4.20%	0.80	11.41%	7.21%	9.97%
TXNM Energy, Inc.	TXNM	4.20%	0.80	11.41%	7.21%	9.99%
Portland General Electric Company	POR	4.20%	0.76	11.41%	7.21%	9.71%
PPL Corporation	PPL	4.20%	0.93	11.41%	7.21%	10.89%
Southern Company	SO	4.20%	0.76	11.41%	7.21%	9.70%
Xcel Energy Inc.	XEL	4.20%	0.71	11.41%	7.21%	9.34%
Median			0.77			9.76%
Mean			0.80			9.93%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 43, No. 11, November 1, 2024 at 2
[2] Source: Bloomberg Professional, as of September 30, 2024
[3] Source: Exhibit JCN-5, page 8
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE, BLOOMBERG BETA, AND
MARKET RISK PREMIUM DERIVED FROM S&P 500 - FERC METHODOLOGY
K = Rf + β (Rm − Rf)

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2026 - 2030)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)
Alliant Energy Corporation	LNT	4.30%	0.77	11.41%	7.11%	9.78%
Ameren Corporation	AEE	4.30%	0.73	11.41%	7.11%	9.50%
American Electric Power Company, In	AEP	4.30%	0.74	11.41%	7.11%	9.54%
Entergy Corporation	ETR	4.30%	0.84	11.41%	7.11%	10.25%
Evergy, Inc.	EVRG	4.30%	0.77	11.41%	7.11%	9.74%
IDACORP, Inc.	IDA	4.30%	0.77	11.41%	7.11%	9.74%
NextEra Energy, Inc.	NEE	4.30%	0.80	11.41%	7.11%	9.99%
NorthWestern Corporation	NWE	4.30%	0.86	11.41%	7.11%	10.39%
OGE Energy Corporation	OGE	4.30%	0.89	11.41%	7.11%	10.62%
Pinnacle West Capital Corporation	PNW	4.30%	0.80	11.41%	7.11%	9.99%
TXNM Energy, Inc.	TXNM	4.30%	0.80	11.41%	7.11%	10.01%
Portland General Electric Company	POR	4.30%	0.76	11.41%	7.11%	9.74%
PPL Corporation	PPL	4.30%	0.93	11.41%	7.11%	10.89%
Southern Company	SO	4.30%	0.76	11.41%	7.11%	9.73%
Xcel Energy Inc.	XEL	4.30%	0.71	11.41%	7.11%	9.37%
Median			0.77			9.78%
Mean			0.80			9.95%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 43, No. 6, June 1, 2024 at 14
[2] Source: Bloomberg Professional, as of September 30, 2024
[3] Source: Exhibit JCN-5, page 8
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

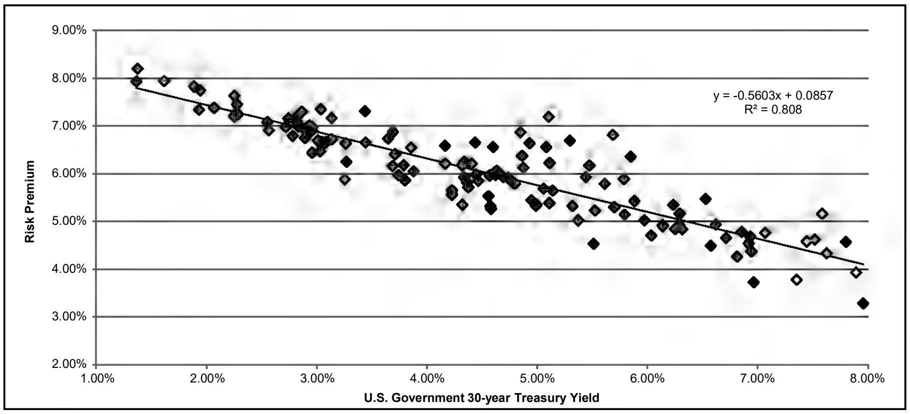
BOND YIELD PLUS RISK PREMIUM ANALYSIS
Risk Premium -- Vertically Integrated Electric Utilities (US)

	[1] Average Authorized VI Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1992.1	12.38%	7.80%	4.58%
1992.2	11.83%	7.89%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.77%
1993.2	11.64%	6.86%	4.79%
1993.3	11.15%	6.31%	4.84%
1993.4	11.04%	6.14%	4.90%
1994.1	11.07%	6.57%	4.49%
1994.2	11.13%	7.35%	3.78%
1994.3	12.75%	7.58%	5.17%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.34%
1995.2	11.32%	6.94%	4.37%
1995.3	11.37%	6.71%	4.66%
1995.4	11.58%	6.23%	5.35%
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.96%	3.74%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.81%	4.27%
1997.2	11.62%	6.93%	4.68%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.14%	4.92%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.47%	6.18%
1998.4	12.30%	5.10%	7.20%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.79%	5.15%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.25%	4.85%
2000.1	11.21%	6.29%	4.92%
2000.2	11.00%	5.97%	5.03%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.44%	5.93%
2001.2	11.00%	5.70%	5.30%
2001.3	10.76%	5.52%	5.23%
2001.4	11.99%	5.30%	6.70%
2002.1	10.05%	5.51%	4.54%
2002.2	11.41%	5.61%	5.79%
2002.3	11.65%	5.08%	6.57%
2002.4	11.57%	4.93%	6.64%
2003.1	11.72%	4.85%	6.87%
2003.2	11.16%	4.60%	6.56%
2003.3	10.50%	5.11%	5.39%
2003.4	11.34%	5.11%	6.23%
2004.1	11.00%	4.88%	6.12%
2004.2	10.64%	5.32%	5.32%
2004.3	10.75%	5.06%	5.69%
2004.4	11.24%	4.86%	6.38%
2005.1	10.63%	4.69%	5.93%
2005.2	10.31%	4.47%	5.85%
2005.3	11.08%	4.44%	6.65%
2005.4	10.63%	4.68%	5.95%
2006.1	10.70%	4.63%	6.06%
2006.2	10.79%	5.14%	5.65%
2006.3	10.35%	4.99%	5.35%
2006.4	10.65%	4.74%	5.91%
2007.1	10.59%	4.80%	5.80%
2007.2	10.33%	4.99%	5.34%
2007.3	10.40%	4.95%	5.45%
2007.4	10.65%	4.61%	6.04%
2008.1	10.62%	4.41%	6.21%
2008.2	10.54%	4.57%	5.97%
2008.3	10.43%	4.44%	5.98%
2008.4	10.39%	3.65%	6.74%
2009.1	10.75%	3.44%	7.31%
2009.2	10.75%	4.17%	6.58%
2009.3	10.50%	4.32%	6.18%
2009.4	10.59%	4.34%	6.26%
2010.1	10.59%	4.62%	5.97%
2010.2	10.18%	4.36%	5.82%
2010.3	10.40%	3.86%	6.55%
2010.4	10.38%	4.17%	6.21%
2011.1	10.09%	4.56%	5.53%
2011.2	10.26%	4.34%	5.92%
2011.3	10.57%	3.69%	6.88%
2011.4	10.39%	3.04%	7.35%
2012.1	10.30%	3.14%	7.17%
2012.2	9.95%	2.93%	7.02%
2012.3	9.90%	2.74%	7.16%
2012.4	10.16%	2.86%	7.30%
2013.1	9.85%	3.13%	6.72%
2013.2	9.86%	3.14%	6.72%

BOND YIELD PLUS RISK PREMIUM ANALYSIS
Risk Premium -- Vertically Integrated Electric Utilities (US)

	[1]	[2]	[3]
	Average Authorized VI Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
2013.3	10.12%	3.71%	6.41%
2013.4	9.97%	3.79%	6.18%
2014.1	9.86%	3.69%	6.17%
2014.2	10.10%	3.44%	6.66%
2014.3	9.90%	3.26%	6.64%
2014.4	9.94%	2.96%	6.98%
2015.1	9.64%	2.55%	7.08%
2015.2	9.83%	2.88%	6.94%
2015.3	9.40%	2.96%	6.44%
2015.4	9.86%	2.96%	6.90%
2016.1	9.70%	2.72%	6.98%
2016.2	9.48%	2.57%	6.91%
2016.3	9.74%	2.28%	7.46%
2016.4	9.83%	2.83%	7.00%
2017.1	9.72%	3.04%	6.67%
2017.2	9.64%	2.90%	6.75%
2017.3	10.00%	2.82%	7.18%
2017.4	9.91%	2.82%	7.09%
2018.1	9.69%	3.02%	6.66%
2018.2	9.75%	3.09%	6.66%
2018.3	9.69%	3.06%	6.63%
2018.4	9.52%	3.27%	6.25%
2019.1	9.72%	3.01%	6.71%
2019.2	9.58%	2.78%	6.79%
2019.3	9.53%	2.29%	7.24%
2019.4	9.89%	2.25%	7.63%
2020.1	9.72%	1.89%	7.83%
2020.2	9.58%	1.38%	8.20%
2020.3	9.30%	1.37%	7.93%
2020.4	9.56%	1.62%	7.94%
2021.1	9.45%	2.07%	7.38%
2021.2	9.47%	2.25%	7.21%
2021.3	9.27%	1.93%	7.34%
2021.4	9.69%	1.94%	7.75%
2022.1	9.45%	2.25%	7.20%
2022.2	9.50%	3.03%	6.47%
2022.3	9.14%	3.26%	5.88%
2022.4	9.94%	3.88%	6.06%
2023.1	9.72%	3.74%	5.97%
2023.2	9.67%	3.80%	5.86%
2023.3	9.79%	4.23%	5.56%
2023.4	9.85%	4.58%	5.27%
2024.1	9.67%	4.32%	5.35%
2024.2	9.90%	4.58%	5.32%
2024.3	9.88%	4.23%	5.65%
2024.4	10.10%	4.38%	5.72%
AVERAGE	10.56%	4.53%	6.03%
MEDIAN	10.46%	4.56%	6.09%

BOND YIELD PLUS RISK PREMIUM ANALYSIS
Risk Premium -- Vertically Integrated Electric Utilities (US)



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.898876091
R Square	0.807978227
Adjusted R Square	0.806501137
Standard Error	0.004412698
Observations	132

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.010651259	0.010651259	547.0065614	2.02972E-48
Residual	130	0.002531348	1.94719E-05		
Total	131	0.013182607			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.085655622	0.00115177	74.36869396	2.0838E-108	0.083376983	0.08793426
X Variable 1	-0.560267003	0.023955144	-23.3881714	2.02972E-48	-0.60765939	-0.5128746

	[7] U.S. Govt. 30-year Treasury	[8] Risk Premium	[9] ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.30%	6.16%	10.46%
Blue Chip Near-Term Projected Forecast (Q4 2024 - Q4 2025) [5]	4.20%	6.21%	10.41%
Blue Chip Long-Term Projected Forecast (2026-2030) [6]	4.30%	6.16%	10.46%
AVERAGE			10.44%

Notes:
[1] Source: Regulatory Research Associates, rate cases through October 31, 2024
[2] Source: Bloomberg Professional, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: Bloomberg Professional, 30-day average as of September 30, 2024
[5] Source: Blue Chip Financial Forecasts, Vol. 43, No. 11, November 1, 2024 at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 43, No. 6, June 1, 2024 at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.085656 + (-0.560267 x Column [7])
[9] Equals Column [7] + Column [8]

EXPECTED EARNINGS ANALYSIS

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
		Value Line ROE 2027-2029	Value Line Total Capital 2023	Value Line Common Equity Ratio 2023	Total Equity 2023	Value Line Total Capital 2027-2029	Value Line Common Equity Ratio 2027-2029	Total Equity 2027-2029	Compound Annual Growth Rate	Adjustment Factor	Adjusted Return on Common Equity
Alliant Energy Corporation	LNT	12.00%	15,002.00	45.20%	6,781	17,070.00	48.00%	8,193.60	3.86%	1.019	12.23%
Ameren Corporation	AEE	10.00%	24,847.00	43.80%	10,883	29,500.00	48.50%	14,307.50	5.62%	1.027	10.27%
American Electric Power Company, Inc.	AEP	11.00%	62,837.00	42.00%	26,392	75,900.00	42.50%	32,257.50	4.10%	1.020	11.22%
Entergy Corporation	ETR	9.50%	37,851.00	38.60%	14,610	50,555.00	39.00%	19,716.45	6.18%	1.030	9.78%
Evergy, Inc.	EVRG	10.00%	20,019.00	48.00%	9,609	23,400.00	46.50%	10,881.00	2.52%	1.012	10.12%
IDACORP, Inc.	IDA	9.00%	5,683.40	51.20%	2,910	7,500.00	50.50%	3,787.50	5.41%	1.026	9.24%
NextEra Energy, Inc.	NEE	13.50%	108,873.00	43.60%	47,469	176,200.00	42.50%	74,885.00	9.55%	1.046	14.12%
NorthWestern Corporation	NWE	8.00%	5,475.40	50.90%	2,787	6,700.00	49.50%	3,316.50	3.54%	1.017	8.14%
OGE Energy Corporation	OGE	13.00%	9,238.20	49.60%	4,582	10,400.00	50.00%	5,200.00	2.56%	1.013	13.16%
Pinnacle West Capital Corporation	PNW	8.50%	13,718.00	45.00%	6,173	18,350.00	48.00%	8,808.00	7.37%	1.036	8.80%
TXNM Energy, Inc.	TXNM	10.00%	6,602.30	35.60%	2,350	10,400.00	30.50%	3,172.00	6.18%	1.030	10.30%
Portland General Electric Company	POR	9.50%	7,513.00	44.20%	3,321	10,900.00	41.00%	4,469.00	6.12%	1.030	9.78%
PPL Corporation	PPL	9.50%	28,544.00	48.80%	13,929	34,280.00	50.50%	17,311.40	4.44%	1.022	9.71%
Southern Company	SO	14.50%	83,654.00	37.60%	31,454	93,500.00	37.00%	34,595.00	1.92%	1.010	14.64%
Xcel Energy Inc.	XEL	11.00%	42,529.00	41.40%	17,607	64,100.00	37.50%	24,037.50	6.42%	1.031	11.34%
Median											10.27%
Mean											10.86%

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Source: Value Line
[4] Equals [2] x [3]
[5] Source: Value Line
[6] Source: Value Line
[7] Equals [5] x [6]
[8] Equals ([7] / [4]) ^ (1/5) - 1
[9] Equals 2 x (1 + [8]) / (2 + [8])
[10] Equals [1] x [9]

REGULATORY FRAMEWORK COMPARISON
DUKE ENERGY KENTUCKY AND PROXY GROUP COMPANIES

Company	Jurisdiction/Service	[1] Test Year	[2] Rate Base	[3] Revenue Decoupling	[4] Capital Cost Recovery Mechanism
Interstate Power and Light Company	Iowa - Electric	Fully Forecast	Average	No	Yes
Wisconsin Power and Light Company	Wisconsin - Electric	Fully Forecast	Average	No	No
Ameren Illinois Company	Illinois - Electric	Historical	Year End	Partial	Yes
Union Electric Company	Missouri - Electric	Historical	Year End	Partial	Yes
Southwestern Electric Power Company	Arkansas - Electric	Historical	Year End	Partial	Yes
Indiana Michigan Power Company	Indiana - Electric	Fully Forecast	Year End	Partial	Yes
Kentucky Power Company	Kentucky - Electric	Historical	Year End	Partial	Yes
Southwestern Electric Power Company	Louisiana - Electric	Historical	Year End	Partial	No
Indiana Michigan Power Company	Michigan - Electric	Fully Forecast	Average	Partial	Yes
Ohio Power Company	Ohio - Electric	Partially Forecast	Year End	Partial	Yes
Public Service Company of Oklahoma	Oklahoma - Electric	Historical	Year End	Partial	Yes
Kingsport Power Company	Tennessee - Electric	Fully Forecast	Average	No	No
AEP Texas Inc.	Texas - Electric	Historical	Year End	No	Yes
Southwestern Electric Power Company	Texas - Electric	Historical	Year End	No	Yes
Appalachian Power Company	Virginia - Electric	Fully Forecast	Year End	No	Yes
Appalachian Power / Wheeling Power	West Virginia - Electric	Historical	Average	No	Yes
Entergy Arkansas, LLC	Arkansas - Electric	Fully Forecast	Average	Partial	Yes
Entergy Louisiana, LLC	Louisiana - Electric	Historical	Average	Partial	Yes
Entergy Mississippi, LLC	Mississippi - Electric	Partially Forecast	Average	Partial	No
Entergy New Orleans, LLC	Louisiana - Electric	Partially Forecast	Year End	No	Yes
Entergy Texas, Inc.	Texas - Electric	Fully Forecast	Year End	No	Yes
Evergy Kansas Central	Kansas - Electric	Historical	Year End	Partial	Yes
Evergy Kansas South	Kansas - Electric	Historical	Year End	Partial	Yes
Evergy Kansas Metro	Kansas - Electric	Historical	Year End	No	Yes
Evergy Missouri Metro	Missouri - Electric	Historical	Year End	Partial	Yes
Evergy Missouri West	Missouri - Electric	Historical	Year End	Partial	Yes
Idaho Power Company	Idaho - Electric	Partially Forecast	Average	Full	No
Idaho Power Company	Oregon - Electric	Fully Forecast	Average	No	No
Florida Power & Light Company	Florida - Electric	Fully Forecast	Average	No	Yes
NorthWestern Energy	Montana - Electric	Historical	Average	No	No
NorthWestern Energy	South Dakota - Electric	Historical	Average	No	No
Oklahoma Gas and Electric Company	Arkansas - Electric	Historical	Year End	Partial	Yes
Oklahoma Gas and Electric Company	Oklahoma - Electric	Historical	Year End	Partial	Yes
Arizona Public Service Company	Arizona - Electric	Historical	Year End	Partial	Yes
Portland General Electric Company	Oregon - Electric	Fully Forecast	Average	No	Yes
Louisville Gas & Electric Co.	Kentucky - Electric	Fully Forecast	Year End	Partial	Yes
PPL Electric Utilities Corp.	Pennsylvania - Electric	Fully Forecast	Year End	No	Yes
The Narragansett Electric Co.	Rhode Island - Electric	Historical	Average	Full	Yes
Kentucky Utilities Co.	Virginia - Electric	Historical	Average	No	No
Alabama Power Company	Alabama - Electric	Fully Forecast	Year End	No	Yes
Georgia Power Company	Georgia - Electric	Fully Forecast	Average	No	Yes
Mississippi Power Company	Mississippi - Electric	Fully Forecast	Year End	Partial	Yes
Public Service Co. of New Mexico	New Mexico - Electric	Historical	Year End	No	Yes
Texas-New Mexico Power Co.	Texas - Electric	Historical	Year End	No	Yes
Public Service Co. of Colorado	Colorado - Electric	Historical	Average	Partial	Yes
Northern States Power Co. MN	Minnesota - Electric	Fully Forecast	Average	Partial	Yes
Southwestern Public Service Co.	New Mexico - Electric	Historical	Year End	No	Yes
Northern States Power Co. MN	North Dakota - Electric	Fully Forecast	Average	No	Yes
Northern States Power Co. MN	South Dakota - Electric	Historical	Average	Partial	Yes
Southwestern Public Service Co.	Texas - Electric	Historical	Year End	No	No
Northern States Power Co. WI	Wisconsin - Electric	Fully Forecast	Average	No	No

		Test Year		Rate Base		Revenue Decoupling		Capital Cost Recovery Mechanism
Proxy Group Operating Company Count	Fully Forecast	19	Year End	29	Full	2	Yes	40
	Partially Forecast	4	Average	22	Partial	24	No	11
	Historical	28	Date Certain	0	No	25		
	Forecast	45%	Year End	57%	RDM	51%	CCRM	78%

Company	Jurisdiction/Service	Test Year	Rate Base	Revenue Decoupling	Capital Cost Recovery Mechanism
Duke Energy Kentucky	Kentucky - Electric	Fully Forecast	Average	Partial	Yes

Notes

[1] Source: S&P Global - Market

[2] Source: S&P Global - Market Intelligence Rate Case History (Past Rate Cases), accessed 8/31/2024

[3] - [4] Source: "Adjustment Clauses: A State-by-state Overview," Regulatory Research Associates, June 2022. Operating subsidiaries not covered in this report were excluded from this exhibit.

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2022Q2	2022Q1	2021Q4	2021Q3	2021Q2	2021Q1	2020Q4	2020Q3	Average
Alliant Energy Corporation	LNT	51.73%	51.56%	52.06%	52.24%	52.31%	52.23%	52.55%	51.35%	52.00%
Ameren Corporation	AEE	53.13%	53.53%	53.05%	53.68%	52.60%	53.04%	53.74%	54.19%	53.37%
American Electric Power Company, Inc.	AEP	47.29%	47.66%	47.27%	47.71%	46.68%	46.36%	46.67%	47.21%	47.11%
Entergy Corporation	ETR	50.33%	50.28%	51.45%	49.95%	49.51%	48.66%	47.19%	47.03%	49.30%
Evergy, Inc.	EVRG	58.54%	59.12%	58.23%	60.44%	59.97%	60.57%	60.41%	61.38%	59.83%
IDACORP, Inc.	IDA	51.54%	49.44%	49.40%	49.36%	52.01%	50.55%	54.36%	54.20%	51.36%
NextEra Energy, Inc.	NEE	58.55%	62.08%	58.09%	58.37%	58.60%	60.61%	62.56%	62.13%	60.12%
NorthWestern Corporation	NWE	50.78%	50.74%	49.89%	50.78%	50.15%	50.91%	50.34%	49.73%	50.41%
OGE Energy Corporation	OGE	52.45%	52.59%	53.07%	52.90%	53.30%	53.22%	55.65%	55.42%	53.58%
Pinnacle West Capital Corporation	OGE	52.45%	52.59%	53.07%	52.90%	53.30%	53.22%	55.65%	55.42%	53.58%
Portland General Electric Company	POR	43.80%	43.62%	45.21%	46.29%	47.64%	46.99%	42.22%	44.76%	45.07%
PPL Corporation	PPL	55.81%	55.23%	55.47%	55.79%	55.81%	55.69%	56.29%	56.52%	55.83%
Southern Company	SO	54.36%	53.86%	53.84%	54.64%	53.00%	54.25%	54.24%	54.06%	54.03%
TXNM Energy, Inc.	TXNM	49.37%	50.76%	50.35%	48.25%	48.17%	49.52%	48.78%	49.53%	49.34%
Xcel Energy Inc.	XEL	53.38%	53.74%	54.26%	53.61%	53.50%	55.35%	54.76%	54.01%	54.07%
MEAN		52.23%	52.45%	52.31%	52.46%	52.44%	52.74%	53.03%	53.13%	52.60%
LOW		43.80%	43.62%	45.21%	46.29%	46.68%	46.36%	42.22%	44.76%	45.07%
HIGH		58.55%	62.08%	58.23%	60.44%	59.97%	60.61%	62.56%	62.13%	60.12%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2022Q2	2022Q1	2021Q4	2021Q3	2021Q2	2021Q1	2020Q4	2020Q3	Average
Interstate Power and Light Company	LNT	50.39%	50.13%	49.74%	49.81%	50.60%	50.59%	50.55%	50.85%	50.33%
Wisconsin Power and Light Company	LNT	53.18%	53.09%	54.68%	55.02%	54.19%	54.02%	54.93%	51.94%	53.88%
Ameren Illinois Company	AEE	54.51%	56.58%	55.48%	55.50%	54.85%	56.32%	55.59%	56.77%	55.70%
Union Electric Company	AEE	51.88%	50.77%	50.86%	52.05%	50.54%	50.16%	52.07%	52.00%	51.29%
AEP Texas, Inc.	AEP	44.11%	44.98%	45.24%	45.24%	42.62%	41.54%	41.64%	41.73%	43.39%
Appalachian Power Company	AEP	49.10%	48.80%	46.65%	46.99%	46.23%	46.67%	46.61%	46.66%	47.21%
Indiana Michigan Power Company	AEP	48.37%	48.22%	47.34%	47.95%	47.85%	47.55%	46.99%	47.80%	47.76%
Kentucky Power Company	AEP	40.67%	40.89%	40.69%	41.13%	40.01%	40.96%	41.20%	42.16%	40.96%
Kingsport Power Company	AEP	51.34%	50.64%	49.98%	49.64%	48.95%	47.91%	50.99%	47.86%	49.66%
Ohio Power Company	AEP	48.80%	49.19%	50.06%	49.48%	49.19%	48.03%	48.64%	48.94%	49.04%
Public Service Company of Oklahoma	AEP	48.95%	48.73%	50.37%	51.10%	49.20%	48.10%	50.76%	52.40%	49.95%
Southwestern Electric Power Company	AEP	48.26%	49.56%	49.61%	50.58%	50.15%	50.06%	49.86%	51.13%	49.90%
Wheeling Power Company	AEP	43.65%	43.99%	38.32%	43.79%	44.62%	46.37%	48.40%	47.71%	44.61%
Entergy Arkansas, Inc.	ETR	46.86%	46.00%	44.47%	45.17%	46.11%	44.79%	47.33%	47.24%	46.00%
Entergy Louisiana, LLC	ETR	52.20%	52.21%	55.01%	52.44%	51.24%	50.66%	46.79%	46.67%	50.90%
Entergy Mississippi, Inc.	ETR	47.25%	47.60%	48.31%	47.01%	46.04%	44.63%	45.50%	44.09%	46.30%
Entergy New Orleans, LLC	ETR	50.07%	51.59%	53.17%	51.97%	47.24%	47.23%	46.88%	46.77%	49.36%
Entergy Texas, Inc.	ETR	51.70%	51.00%	50.72%	49.40%	51.16%	50.37%	49.99%	50.62%	50.62%
Evergy Metro	EVRG	50.39%	52.24%	51.99%	51.75%	51.87%	55.04%	52.01%	53.19%	52.31%
Evergy Kansas South	EVRG	82.88%	83.97%	84.28%	85.09%	83.65%	83.73%	83.43%	83.66%	83.83%
Evergy Missouri West, Inc.	EVRG	48.84%	52.88%	49.29%	54.74%	53.89%	53.46%	52.21%	56.48%	52.72%
Westar Energy (KPL)	EVRG	56.18%	54.20%	53.58%	56.61%	56.21%	55.48%	58.01%	58.02%	56.04%
Idaho Power Co.	IDA	51.54%	49.44%	49.40%	49.36%	52.01%	50.55%	54.36%	54.20%	51.36%
Florida Power & Light Company	NEE	58.55%	62.08%	58.09%	58.37%	58.60%	60.61%	62.56%	62.13%	60.12%
NorthWestern Corporation	NWE	50.78%	50.74%	49.89%	50.78%	50.15%	50.91%	50.34%	49.73%	50.41%
Oklahoma Gas and Electric Company	OGE	52.45%	52.59%	53.07%	52.90%	53.30%	53.22%	55.65%	55.42%	53.58%
Arizona Public Service Company	PNW	50.35%	49.47%	49.41%	50.05%	48.66%	50.67%	50.10%	52.22%	50.12%
Portland General Electric Company	POR	43.80%	43.62%	45.21%	46.29%	47.64%	46.99%	42.22%	44.76%	45.07%
Kentucky Utilities Company	PPL	53.76%	52.95%	53.18%	53.29%	53.14%	52.69%	53.58%	53.29%	53.23%
Louisville Gas and Electric Company	PPL	52.69%	52.53%	52.49%	52.61%	52.59%	52.51%	54.14%	53.28%	52.85%
Narragansett Electric Company	PPL	61.04%	59.51%	60.21%	61.80%	62.30%	62.30%	63.21%	65.89%	62.03%
PPL Electric Utilities Corporation	PPL	56.12%	55.90%	56.24%	56.25%	56.18%	56.18%	56.02%	56.09%	56.12%
Alabama Power Company	SO	53.32%	53.09%	52.13%	52.16%	52.26%	52.60%	51.97%	52.40%	52.49%
Georgia Power Company	SO	55.06%	54.44%	54.79%	56.28%	53.45%	55.30%	55.63%	54.98%	54.99%
Mississippi Power Company	SO	53.51%	52.56%	54.69%	54.04%	53.24%	54.34%	55.37%	56.13%	54.23%
Public Service Company of New Mexico	TXNM	49.37%	50.76%	50.35%	48.25%	48.17%	49.52%	48.78%	49.53%	49.34%
Northern States Power Company - MN	XEL	52.13%	51.60%	52.46%	52.30%	52.06%	53.04%	52.70%	52.04%	52.29%
Northern States Power Company - WI	XEL	52.49%	54.32%	52.62%	52.29%	51.91%	54.26%	53.30%	53.14%	53.04%
Public Service Company of Colorado	XEL	54.28%	55.82%	56.19%	54.75%	55.13%	58.23%	57.08%	55.86%	55.92%
Southwestern Public Service Company	XEL	54.23%	53.40%	54.14%	54.20%	53.33%	54.12%	54.25%	54.16%	53.98%

Notes:
[1] Ratios are weighted by actual common capital, short-term debt, and long-term debt of Operating Subsidiaries.
[2] Electric Operating Subsidiaries with data listed as N/A from S&P Capital IQ have been excluded from the analysis.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2022Q2	2022Q1	2021Q4	2021Q3	2021Q2	2021Q1	2020Q4	2020Q3	Average
Alliant Energy Corporation	LNT	48.21%	48.37%	47.87%	47.67%	47.61%	47.69%	47.36%	48.57%	47.92%
Ameren Corporation	AEE	46.52%	45.84%	44.88%	45.92%	47.01%	46.60%	45.93%	45.47%	46.02%
American Electric Power Company, Inc.	AEP	50.69%	49.30%	50.29%	50.49%	51.08%	49.88%	49.44%	50.48%	50.21%
Entergy Corporation	ETR	48.61%	48.67%	47.48%	49.01%	49.45%	50.31%	51.73%	51.92%	49.64%
Evergy, Inc.	EVRG	40.02%	38.67%	38.64%	39.11%	39.44%	38.91%	38.94%	37.31%	38.88%
IDACORP, Inc.	IDA	48.40%	50.51%	50.57%	50.62%	47.94%	49.41%	45.62%	45.74%	48.60%
NextEra Energy, Inc.	NEE	40.47%	36.96%	40.92%	40.68%	40.49%	38.48%	36.51%	36.97%	38.94%
NorthWestern Corporation	NWE	49.22%	49.26%	50.11%	49.22%	49.85%	49.09%	49.66%	50.27%	49.59%
OGE Energy Corporation	OGE	46.35%	45.39%	46.07%	46.38%	46.70%	46.78%	44.35%	44.58%	45.83%
Pinnacle West Capital Corporation	OGE	46.35%	45.39%	46.07%	46.38%	46.70%	46.78%	44.35%	44.58%	45.83%
Portland General Electric Company	POR	55.88%	56.06%	54.44%	53.32%	52.04%	52.77%	55.43%	53.37%	54.17%
PPL Corporation	PPL	43.78%	44.23%	42.73%	42.85%	42.95%	43.12%	42.87%	43.03%	43.19%
Southern Company	SO	44.76%	45.19%	44.38%	44.67%	46.17%	44.26%	45.13%	44.63%	44.90%
TXNM Energy, Inc.	TXNM	50.48%	49.02%	49.49%	51.60%	51.68%	50.32%	51.07%	50.32%	50.50%
Xcel Energy Inc.	XEL	46.45%	45.24%	45.35%	45.76%	46.09%	44.45%	45.08%	45.39%	45.48%
MEAN		47.08%	46.54%	46.62%	46.91%	47.01%	46.59%	46.23%	46.18%	46.65%
LOW		40.02%	36.96%	38.64%	39.11%	39.44%	38.48%	36.51%	36.97%	38.88%
HIGH		55.88%	56.06%	54.44%	53.32%	52.04%	52.77%	55.43%	53.37%	54.17%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2022Q2	2022Q1	2021Q4	2021Q3	2021Q2	2021Q1	2020Q4	2020Q3	Average
Interstate Power and Light Company	LNT	49.61%	49.87%	50.26%	50.19%	49.40%	49.41%	49.45%	49.15%	49.67%
Wisconsin Power and Light Company	LNT	46.68%	46.76%	45.16%	44.80%	45.62%	45.80%	44.88%	47.89%	45.95%
Ameren Illinois Company	AEE	45.07%	42.43%	42.91%	43.92%	44.58%	43.17%	43.98%	42.77%	43.61%
Union Electric Company	AEE	47.83%	48.92%	46.65%	47.70%	49.22%	49.61%	47.69%	47.77%	48.17%
AEP Texas, Inc.	AEP	55.89%	52.55%	53.78%	54.76%	56.05%	53.84%	57.33%	58.27%	55.31%
Appalachian Power Company	AEP	50.17%	50.48%	49.65%	50.49%	50.70%	49.80%	50.98%	52.61%	50.61%
Indiana Michigan Power Company	AEP	50.08%	49.92%	50.62%	51.22%	51.38%	51.74%	48.35%	49.82%	50.39%
Kentucky Power Company	AEP	54.87%	55.23%	55.58%	52.67%	52.02%	52.25%	52.83%	53.89%	53.67%
Kingsport Power Company	AEP	46.44%	47.13%	47.80%	48.06%	49.00%	48.74%	43.64%	41.59%	46.55%
Ohio Power Company	AEP	49.85%	45.79%	47.52%	48.07%	48.91%	44.68%	47.12%	48.28%	47.53%
Public Service Company of Oklahoma	AEP	44.97%	44.79%	46.97%	47.69%	48.22%	48.09%	40.36%	41.48%	45.32%
Southwestern Electric Power Company	AEP	47.11%	46.29%	48.27%	47.85%	48.48%	48.78%	45.04%	45.81%	47.21%
Wheeling Power Company	AEP	56.14%	55.61%	57.52%	48.30%	50.23%	47.11%	50.09%	43.39%	51.05%
Entergy Arkansas, Inc.	ETR	51.88%	52.63%	54.18%	53.54%	52.59%	53.97%	51.37%	51.49%	52.71%
Entergy Louisiana, LLC	ETR	47.00%	47.03%	44.19%	46.79%	48.00%	48.58%	52.41%	52.55%	48.32%
Entergy Mississippi, Inc.	ETR	50.80%	50.40%	49.64%	50.99%	51.97%	53.41%	52.50%	53.95%	51.71%
Entergy New Orleans, LLC	ETR	47.70%	46.09%	44.61%	45.76%	50.58%	50.56%	50.91%	51.07%	48.41%
Entergy Texas, Inc.	ETR	47.65%	48.34%	48.63%	49.94%	48.12%	48.91%	49.28%	48.67%	48.69%
Evergy Metro	EVRG	49.59%	47.73%	47.99%	48.22%	48.10%	44.92%	47.95%	46.78%	47.66%
Evergy Kansas South	EVRG	13.93%	14.34%	14.60%	14.84%	14.82%	16.19%	16.29%	16.26%	15.16%
Evergy Missouri West, Inc.	EVRG	46.17%	41.41%	38.69%	43.30%	44.11%	44.51%	43.76%	36.35%	42.29%
Westar Energy (KPL)	EVRG	43.59%	43.07%	43.52%	43.00%	43.74%	43.97%	41.95%	41.04%	42.99%
Idaho Power Co.	IDA	48.40%	50.51%	50.57%	50.62%	47.94%	49.41%	45.62%	45.74%	48.60%
Florida Power & Light Company	NEE	40.47%	36.96%	40.92%	40.68%	40.49%	38.48%	36.51%	36.97%	38.94%
NorthWestern Corporation	NWE	49.22%	49.26%	50.11%	49.22%	49.85%	49.09%	49.66%	50.27%	49.59%
Oklahoma Gas and Electric Company	OGE	46.35%	45.39%	46.07%	46.38%	46.70%	46.78%	44.35%	44.58%	45.83%
Arizona Public Service Company	PNW	49.38%	50.25%	50.30%	49.67%	51.06%	49.03%	49.60%	47.48%	49.60%
Portland General Electric Company	POR	55.88%	56.06%	54.44%	53.32%	52.04%	52.77%	55.43%	53.37%	54.17%
Kentucky Utilities Company	PPL	45.48%	45.94%	46.29%	45.86%	46.21%	46.66%	45.90%	45.85%	46.02%
Louisville Gas and Electric Company	PPL	46.31%	46.82%	46.86%	46.62%	46.76%	46.85%	45.23%	45.80%	46.41%
Narragansett Electric Company	PPL	38.79%	39.63%	31.10%	32.36%	32.21%	32.44%	33.39%	33.86%	34.22%
PPL Electric Utilities Corporation	PPL	43.83%	44.06%	43.72%	43.71%	43.79%	43.78%	43.94%	43.87%	43.84%
Alabama Power Company	SO	46.22%	46.47%	47.43%	47.39%	47.28%	46.94%	47.56%	47.14%	47.05%
Georgia Power Company	SO	44.02%	44.30%	42.49%	42.91%	45.60%	42.66%	43.63%	43.05%	43.58%
Mississippi Power Company	SO	43.34%	46.70%	44.73%	44.83%	44.75%	42.99%	44.09%	43.34%	44.35%
Public Service Company of New Mexico	TXNM	50.48%	49.02%	49.49%	51.60%	51.68%	50.32%	51.07%	50.32%	50.50%
Northern States Power Company - MN	XEL	47.69%	48.20%	47.32%	47.49%	47.74%	46.75%	47.13%	47.76%	47.51%
Northern States Power Company - WI	XEL	47.24%	44.69%	47.09%	47.42%	47.81%	45.45%	46.42%	46.58%	46.59%
Public Service Company of Colorado	XEL	45.54%	42.57%	43.31%	43.95%	44.70%	41.60%	42.75%	42.91%	43.42%
Southwestern Public Service Company	XEL	45.65%	45.11%	45.36%	45.70%	45.17%	45.69%	45.66%	45.75%	45.51%

Notes:
[1] Ratios are weighted by actual common capital, short-term debt, and long-term debt of Operating Subsidiaries.
[2] Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

CAPITAL STRUCTURE ANALYSIS

SHORT-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2022Q2	2022Q1	2021Q4	2021Q3	2021Q2	2021Q1	2020Q4	2020Q3	Average
Alliant Energy Corporation	LNT	0.07%	0.07%	0.07%	0.09%	0.09%	0.08%	0.09%	0.08%	0.08%
Ameren Corporation	AEE	0.35%	0.63%	2.07%	0.40%	0.40%	0.36%	0.33%	0.34%	0.61%
American Electric Power Company, Inc.	AEP	2.02%	3.04%	2.43%	1.80%	2.23%	3.76%	3.89%	2.31%	2.69%
Entergy Corporation	ETR	1.06%	1.06%	1.08%	1.04%	1.04%	1.04%	1.08%	1.05%	1.06%
Evergy, Inc.	EVRG	1.43%	2.21%	3.13%	0.44%	0.60%	0.52%	0.65%	1.32%	1.29%
IDACORP, Inc.	IDA	0.06%	0.05%	0.02%	0.02%	0.05%	0.04%	0.02%	0.06%	0.04%
NextEra Energy, Inc.	NEE	0.99%	0.96%	0.98%	0.95%	0.91%	0.91%	0.93%	0.90%	0.94%
NorthWestern Corporation	NWE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OGE Energy Corporation	OGE	1.20%	2.02%	0.86%	0.71%	0.00%	0.00%	0.00%	0.00%	0.60%
Pinnacle West Capital Corporation	OGE	1.20%	2.02%	0.86%	0.71%	0.00%	0.00%	0.00%	0.00%	0.60%
Portland General Electric Company	POR	0.33%	0.31%	0.35%	0.39%	0.32%	0.24%	2.34%	1.86%	0.77%
PPL Corporation	PPL	0.41%	0.54%	1.80%	1.36%	1.24%	1.20%	0.85%	0.45%	0.98%
Southern Company	SO	0.88%	0.95%	1.79%	0.70%	0.83%	1.49%	0.63%	1.31%	1.07%
TXNM Energy, Inc.	TXNM	0.15%	0.22%	0.16%	0.15%	0.15%	0.16%	0.16%	0.15%	0.16%
Xcel Energy Inc.	XEL	0.18%	1.02%	0.38%	0.64%	0.41%	0.19%	0.16%	0.60%	0.45%
MEAN		0.69%	1.01%	1.07%	0.63%	0.55%	0.67%	0.74%	0.69%	0.76%
LOW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
HIGH		2.02%	3.04%	3.13%	1.80%	2.23%	3.76%	3.89%	2.31%	2.69%

SHORT-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2022Q2	2022Q1	2021Q4	2021Q3	2021Q2	2021Q1	2020Q4	2020Q3	Average
Interstate Power and Light Company	LNT	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Wisconsin Power and Light Company	LNT	0.14%	0.15%	0.15%	0.18%	0.18%	0.18%	0.19%	0.18%	0.17%
Ameren Illinois Company	AEE	0.42%	1.00%	1.61%	0.58%	0.57%	0.51%	0.43%	0.47%	0.70%
Union Electric Company	AEE	0.29%	0.31%	2.49%	0.24%	0.24%	0.23%	0.24%	0.23%	0.53%
AEP Texas, Inc.	AEP	0.00%	2.47%	0.98%	0.00%	1.34%	4.62%	1.03%	0.00%	1.30%
Appalachian Power Company	AEP	0.73%	0.72%	3.71%	2.52%	3.07%	3.53%	2.41%	0.73%	2.18%
Indiana Michigan Power Company	AEP	1.55%	1.86%	2.04%	0.83%	0.77%	0.71%	4.66%	2.38%	1.85%
Kentucky Power Company	AEP	4.46%	3.88%	3.73%	6.20%	7.96%	6.79%	5.96%	3.95%	5.37%
Kingsport Power Company	AEP	2.22%	2.23%	2.22%	2.30%	2.05%	3.35%	5.38%	10.55%	3.79%
Ohio Power Company	AEP	1.35%	5.02%	2.42%	2.45%	1.90%	7.29%	4.24%	2.78%	3.43%
Public Service Company of Oklahoma	AEP	6.08%	6.48%	2.66%	1.21%	2.58%	3.81%	8.88%	6.12%	4.73%
Southwestern Electric Power Company	AEP	4.63%	4.15%	2.12%	1.57%	1.37%	1.16%	5.10%	3.06%	2.90%
Wheeling Power Company	AEP	0.21%	0.39%	4.16%	7.91%	5.15%	6.52%	1.51%	8.90%	4.34%
Entergy Arkansas, Inc.	ETR	1.26%	1.37%	1.35%	1.29%	1.29%	1.25%	1.30%	1.27%	1.30%
Entergy Louisiana, LLC	ETR	0.81%	0.77%	0.80%	0.77%	0.75%	0.76%	0.80%	0.77%	0.78%
Entergy Mississippi, Inc.	ETR	1.96%	2.01%	2.04%	1.99%	2.00%	1.96%	2.00%	1.96%	1.99%
Entergy New Orleans, LLC	ETR	2.22%	2.31%	2.22%	2.27%	2.18%	2.22%	2.21%	2.16%	2.22%
Entergy Texas, Inc.	ETR	0.65%	0.66%	0.65%	0.66%	0.72%	0.72%	0.72%	0.71%	0.69%
Evergy Metro	EVRG	0.02%	0.02%	0.03%	0.03%	0.03%	0.03%	0.03%	0.04%	0.03%
Evergy Kansas South	EVRG	3.20%	1.69%	1.12%	0.07%	1.53%	0.08%	0.28%	0.09%	1.01%
Evergy Missouri West, Inc.	EVRG	4.99%	5.71%	12.02%	1.96%	2.00%	2.03%	4.03%	7.17%	4.99%
Westar Energy (KPL)	EVRG	0.24%	2.72%	2.89%	0.39%	0.05%	0.55%	0.04%	0.93%	0.98%
Idaho Power Co.	IDA	0.06%	0.05%	0.02%	0.02%	0.05%	0.04%	0.02%	0.06%	0.04%
Florida Power & Light Company	NEE	0.99%	0.96%	0.98%	0.95%	0.91%	0.91%	0.93%	0.90%	0.94%
NorthWestern Corporation	NWE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Oklahoma Gas and Electric Company	OGE	1.20%	2.02%	0.86%	0.71%	0.00%	0.00%	0.00%	0.00%	0.60%
Arizona Public Service Company	PNW	0.27%	0.29%	0.29%	0.27%	0.29%	0.29%	0.30%	0.31%	0.29%
Portland General Electric Company	POR	0.33%	0.31%	0.35%	0.39%	0.32%	0.24%	2.34%	1.86%	0.77%
Kentucky Utilities Company	PPL	0.76%	1.12%	0.53%	0.85%	0.65%	0.65%	0.52%	0.86%	0.74%
Louisville Gas and Electric Company	PPL	1.00%	0.66%	0.65%	0.77%	0.65%	0.64%	0.63%	0.91%	0.74%
Narragansett Electric Company	PPL	0.17%	0.86%	8.69%	5.84%	5.48%	5.26%	3.40%	0.26%	3.74%
PPL Electric Utilities Corporation	PPL	0.05%	0.04%	0.04%	0.03%	0.04%	0.04%	0.04%	0.04%	0.04%
Alabama Power Company	SO	0.45%	0.44%	0.45%	0.44%	0.46%	0.46%	0.47%	0.46%	0.45%
Georgia Power Company	SO	0.92%	1.27%	2.72%	0.81%	0.95%	2.04%	0.74%	1.97%	1.43%
Mississippi Power Company	SO	3.15%	0.74%	0.58%	1.13%	2.02%	2.67%	0.54%	0.53%	1.42%
Public Service Company of New Mexico	TXNM	0.15%	0.22%	0.16%	0.15%	0.15%	0.16%	0.16%	0.15%	0.16%
Northern States Power Company - MN	XEL	0.18%	0.20%	0.22%	0.21%	0.20%	0.21%	0.16%	0.20%	0.20%
Northern States Power Company - WI	XEL	0.27%	1.00%	0.29%	0.29%	0.28%	0.30%	0.28%	0.28%	0.37%
Public Service Company of Colorado	XEL	0.18%	1.61%	0.49%	1.31%	0.17%	0.17%	0.18%	1.22%	0.67%
Southwestern Public Service Company	XEL	0.11%	1.49%	0.50%	0.11%	1.50%	0.18%	0.10%	0.09%	0.51%

Notes:
[1] Ratios are weighted by actual common capital, short-term debt, and long-term debt of Operating Subsidiaries.
[2] Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

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. 2024-00354

DIRECT TESTIMONY OF

JOHN R. PANIZZA

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 2, 2024

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John R. Panizza and my business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS) as Director, Tax Operations. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Science degree in Accounting from Montclair State University and a Master's in Taxation from Seton Hall University. I am a Certified Public Accountant in the state of New Jersey. My professional work experience began in 1989 as an auditor with KPMG. From 1993 to 2002, I held a number of financial positions primarily at two companies, in telecommunications and automotive (AT&T Corp., and Collins & Aikman Inc.). In 2002, I joined Duke Energy and have held a number of financial positions of increasing responsibilities, including various accounting and tax related positions. In March 2018, after a three-year rotation primarily in Corporate Accounting, I moved back into the role of Director, Tax Operations, a position that I had previously held.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS DIRECTOR, TAX OPERATIONS.

A. As Director, Tax Operations, I have overall responsibility for corporate tax compliance and accounting for Duke Energy. The Duke Energy Tax Operations Department is responsible for all federal, state, and local income tax returns for Duke Energy, including various joint ventures if Duke Energy is the designated tax matters partner.

The Tax Department is responsible for maintaining and reconciling Duke Energy's tax accounts and for the reporting and disclosure of tax-related matters, to the extent required.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony addresses Duke Energy Kentucky's income tax expense presented in this filing and certain other tax matters. I sponsor Schedule B-6 and Schedule E-1 and E-2 in response to Filing Requirements FR 16(8)(b) and FR 16(8)(e) respectfully. I also provided certain additional tax information to other witnesses for their use in certain calculations for the base period and the forecasted period.

II. SCHEDULES SPONSORED BY WITNESS

Q. PLEASE DESCRIBE SCHEDULE B-6.

A. Schedule B-6 includes the Accumulated Deferred Investment Tax Credit, Accumulated Deferred Income Tax (ADIT) and Excess accumulated Deferred Income Tax (EDIT) balance information.

Q. PLEASE DESCRIBE SCHEDULE E-1.

A. Schedule E-1 is the calculation of adjusted jurisdictional federal and state taxable income and federal and state income tax expense for the base period under current income tax rates and for the forecasted period at income tax rates in effect for that period. Included within this calculation is an amortization of EDITs.

Q. PLEASE DESCRIBE SCHEDULE E-2.

A. Schedule E-2 is for the calculation of jurisdictional federal and state taxable income and federal and state income tax expense. Since the utility taxes are 100 percent jurisdictional, this schedule is not applicable.

Q. WHAT TAX INFORMATION DID YOU PROVIDE TO OTHER WITNESSES?

A. I provided Duke Energy Kentucky witness Mr. Grady "Tripp" S. Carpenter with the property tax expense for the forecasted financial data. These expenses are based on projected property tax rates applied to the most recent valuations as approved by the Kentucky Department of Revenue (KDR), updated for projected additions, retirements, and additional depreciation.

I also provided Mr. Carpenter with the income tax rates and the amortization of the investment tax credit and EDIT for both the forecasted portion of the base period consisting of the six months ending February 28, 2025, and the forecasted test period ending June 30, 2026.

I reviewed Mr. Carpenter's calculation of deferred income taxes for the base period and the forecasted period, I provided the amount of tax depreciation he used for this calculation, and I support the methodology he used for calculating deferred income taxes. I also provided Duke Energy Kentucky witness Mr. Thomas J. Heath, Jr. with the accumulated deferred investment tax credit balance for his use on Schedule J-1.

III. INCOME TAX EXPENSE

Q. WHAT TAX RATE DID THE COMPANY USE TO CALCULATE ITS TEST PERIOD FEDERAL INCOME TAX EXPENSE?

A. The Company used the statutory federal corporate income tax rate of 21 percent for both the base period and forecasted period.

Q. WHAT TAX RATE DID THE COMPANY USE TO CALCULATE ITS TEST PERIOD STATE INCOME TAX EXPENSE?

A. The Company used the composite statutory Kentucky corporate income tax rate of 5 percent for both the base period and the forecast period.

Q. HOW IS THE EDIT RELATING TO THE TAX CUTS AND JOBS ACT (TCJA) BEING FLOWED BACK TO CUSTOMERS?

A. Per the Commission Order in Case No. 2017-00321, the protected EDIT is amortized using Average Rate Assumption Method (ARAM) and the unprotected EDIT is amortized over 10 years.

Q. HOW IS THE EDIT RELATING TO THE KY STATE INCOME TAX REDUCTION BEING FLOWED BACK TO CUSTOMERS?

A. Per the Commission Order in Case No. 2019-00271, Kentucky state EDIT is being returned to the customer over a 10-year amortization period.

Q. WHAT IS THE COMBINED FEDERAL AND STATE STATUTORY INCOME TAX RATE APPLICABLE DURING THE TEST PERIOD?

A. The combined federal and state statutory income tax rate for Duke Energy Kentucky, which is expected to be in effect during the base period and for the forecasted period is 24.925 percent. This rate includes the statutory federal corporate income tax rate of 21 percent and the composite statutory Kentucky corporate income tax rate of 5 percent. State income taxes are deductible in computing the federal tax liability and this deduction is considered in computing the overall effective tax liability. I provided this information to Company witness Ms. Lisa D. Steinkuhl for her use in calculating the revenue requirement. I also provided her with the amount of income tax expense for the base period and the forecasted test period, based on these income tax rates.

Q. WHY DID YOU USE THE STATUTORY KENTUCKY INCOME TAX RATE INSTEAD OF THE EFFECTIVE KENTUCKY INCOME TAX RATE TO CALCULATE DUKE ENERGY KENTUCKY'S INCOME TAX EXPENSE?

A. In my opinion, Duke Energy Kentucky should use the income tax rate that most accurately reflects the actual state income tax for its business on a stand-alone basis, which is the composite statutory rate of 5.0 percent. These are the proper tax rates to apply to Duke Energy Kentucky's electric business operations.

IV. PROPERTY TAX EXPENSE

Q. HOW DID DUKE ENERGY KENTUCKY CALCULATE THE PROPERTY TAX EXPENSE FOR THE FORECASTED TEST PERIOD?

A. Duke Energy Kentucky's forecasted property tax expense for assets located in Kentucky, Ohio, and North Carolina was calculated using most recent actual assessed values and tax rates, along with estimated growth rates. The estimated growth rates were derived from projected investments in property, plant, and equipment (PP&E) and net operating income. Since Duke Energy Kentucky actively manages property tax values with the Kentucky Department of Revenue (KDR), the forecasted property tax expense is determined by estimating adjustments to property tax values.

V. CONCLUSION

Q. WAS THE TAX INFORMATION YOU SUPPLIED FOR SCHEDULE B-6 AND SCHEDULES E-1 AND E-2 AND THE TAX INFORMATION YOU SUPPLIED TO OTHER WITNESSES, PREPARED UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

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. 2024-00354

DIRECT TESTIMONY OF

BRUCE L. SAILERS

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 2, 2024

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bruce L. Sailers, and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS) as Director, Jurisdictional Rate Administration for Duke Energy Kentucky, Inc., (Duke Energy Kentucky or the Company) and Duke Energy Ohio, Inc. DEBS provides various administrative and other services to Duke Energy Kentucky and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor's Degree in Finance and Quantitative Analysis and a Master's Degree in Marketing from the University of Cincinnati. After three years working with Marathon Oil Company as a systems analyst, I began my career in 1990 with The Cincinnati Gas & Electric Company, a predecessor to Duke Energy Ohio, in Load Forecasting. Through 2014, over varying lengths of time, I worked in Load Forecasting, Market Research, and Product Development Analytics (Demand Response). I assumed my current role under the title Rates and Regulatory Strategy Manager, Pricing & Rate Options, in January 2014. Having the same responsibilities, my title has since changed to Manager, Rates and Regulatory Strategy and again to Director, Jurisdictional Rate Administration.

Q. PLEASE DESCRIBE YOUR DUTIES AS DIRECTOR, JURISDICTIONAL RATE ADMINISTRATION.

A. As Director, Jurisdictional Rate Administration, I am responsible for rate design, as well as certain duties related to tariff administration, billing, and revenue reporting in Kentucky and Ohio. I prepare filings to modify charges and terms in Duke Energy Kentucky's retail tariffs and develop rates for new services. During major rate cases, I am responsible for the design of new base rates. Additionally, I frequently work with Duke Energy Kentucky’s customer contact and billing personnel to answer rate-related questions and to apply the retail tariffs to specific situations. Occasionally, I meet with customers and Company representatives to explain rates or provide rate training. I also prepare reports that are required by regulatory authorities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes. In addition, I have also provided testimony in cases before the Indiana Utility Regulatory Commission, the North Carolina Utilities Commission, and the Public Utilities Commission of Ohio.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am responsible for Duke Energy Kentucky’s proposed electric rate designs. My testimony will demonstrate that the rates Duke Energy Kentucky proposes are just and reasonable, that they reflect appropriate rate making principles, and that they result in an equitable basis for recovery of Duke Energy Kentucky’s revenue requirements across its various customer classes and rate schedules. I describe changes that have been made to the Company's retail electric rate schedules, riders, and electric Service Regulations and quantify the effect of these changes to our retail electric customers. I sponsor Schedules L, L-1, L-2.1, L-2.2, M, M-2.1 through M-2.3 and N. I also sponsor Filing Requirements (FR) FR 16(1)(b)(3), FR 16(1)(b)(4), FR 16(8)(l), FR 16(8)(m) and FR 16(8)(n). The "L" series of schedules satisfy FR 16(1)(b)(3), FR 16(1)(b)(4), and FR 16(8)(l). The "M" series of schedules satisfies FR 16(8)(m), and the "N" schedule satisfies FR 16(8)(n). Finally, I sponsor the content required in the Company's publication notice under 807 KAR 5:001 Section 17, as reflected in FR 17(4).

II. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE SCHEDULE L.

A. Schedule L has four parts. The first part, identified as Schedule L, is my "Narrative Rationale for Tariff Changes." This schedule describes the changes to Duke Energy Kentucky's current tariffs and the reasons for those changes. The Company uses the current tariff sheets as the starting point for changes but notes that several tariff sheets have recently been filed with the Commission on October 31, 2024, which may become effective during this proceeding. Those tariff sheets include Sheet No. 10, Index, Sheet No. 89, Net Metering, and Sheet No. 92, Distribution Pole Attachments. As part of the same referenced filings, new Sheet No. 83, Interconnection, and Sheet No. 84, Net Metering II, have been filed.

Q. PLEASE DESCRIBE SCHEDULE L-1.

A. Schedule L-1 shows the rate schedules that Duke Energy Kentucky proposes to implement. Please note that schedules related to the Company's Demand Side Management (DSM) programs are not presented here except for Sheet No. 75 and 78. No changes to the DSM programs are proposed with this filing. However, Sheet No. 75, Demand Side Management, does have a small revision to remove reference to a non-existing rate schedule.

Q. PLEASE DESCRIBE SCHEDULE L-2.1.

A. Schedule L-2.1 contains Duke Energy Kentucky's current rate schedules indicating through underlining where changes occur in the proposed rate schedules. Note that the following schedule sheet numbers do not contain any changes. There are no changes proposed to the following tariff schedules including sheet numbers: 20, 21, 22, 23, 24, 25, 26, 27, 59, 65, 67, 70, 71, 72, 73, 74, 76, 77, 78, 79, 85, 86, 87, 88, 89, 90, 93, 94, 95, 96, 97, 98, 100, and 101. Similar to Schedule L-1, DSM program rate schedules are not presented except for Sheet No. 75 and 78. Note that new proposed rate schedules do not appear in Schedule L-2.1. For reference, the Company is not proposing any new rate schedules in this proceeding.

Q. PLEASE DESCRIBE SCHEDULE L-2.2.

A. Schedule L-2.2 contains Duke Energy Kentucky's proposed rate schedules, showing the revisions that Duke Energy Kentucky proposes in this filing. Proposed changes are crossed out and underscored and coded by letter in the right-hand margin. Similar to Schedule L-1, DSM related program schedules are not presented except for Sheet No. 75.

Q. PLEASE DESCRIBE SCHEDULE M.

A. Schedule M is a one page, side-by-side comparison of Duke Energy Kentucky's test period revenues at current and proposed rates; noting that the current fuel adjustment clause (FAC) value is calculated to match fuel revenues in the Company's test period revenue requirement in order to remove any revenue variations sourced from fuel cost. The Environmental Surcharge Mechanism Rider (Rider ESM) value is also calculated to match targeted revenues in the Company's test period. Schedule M shows that Duke Energy Kentucky is proposing a 16.2 percent increase for the Residential class, a 14.1 percent increase in the Distribution class, on average, an 8.0 percent increase in the Transmission class, and a 13.6 percent increase in Lighting rates, on average. These average class level increases are based upon base rates which include the fuel cost adjustment expense and applicable riders.

Q. PLEASE DESCRIBE SCHEDULE M-2.1.

A. Schedule M-2.1 shows test period base revenue dollars at current rates with the calculated FAC and ESM values and the percentage distribution among the various rate classes, as well as a breakdown of total revenue. Schedule M-2.1 also shows the actual base revenue average rates per kilowatt-hour (kWh) for each rate class.

Q. PLEASE DESCRIBE SCHEDULES M-2.2 AND M-2.3.

A. Schedule M-2.2, page 1, shows the test period bills in summary form, base revenues under current rates, current total revenues, and proposed base revenue increases, all broken down by rate and revenue class. The billing determinants used on these schedules are normalized sales for the 12 months ended June 30, 2026. Schedule M-2.2, pages 2 through 24, contains a detailed calculation of test period numbers using current rates as well as the proposed revenue increase, by rate and revenue class, as summarized on Schedule M-2.2, page 1. Schedule M-2.3 is almost identical to M-2.2, page 1, except that it shows the revenue summary and detailed data calculated at the rates proposed in this case.

Q. PLEASE DESCRIBE SCHEDULE N.

A. Schedule N shows monthly bill comparisons for various consumption levels under each of Duke Energy Kentucky's primary tariff schedules, Rates RS, DS, DT, DP, and TT. This schedule allows comparisons and assessment of how these changes impact customers' bills.

Q. PLEASE DESCRIBE FR 16(1)(b)(3).

A. FR 16(1)(b)(3) shows the proposed tariffs in a form complying with 807 KAR 5:011 Section 6. The effective dates of these tariffs are not less than 30 days from the date of the filing of the application in the present case. This filing requirement is met by the L series of schedules I previously described.

Q. PLEASE DESCRIBE FR 16(1)(b)(4).

A. FR 16(1)(b)(4) consists of Duke Energy Kentucky's current tariffs in a comparative form showing proposed changes. The changes are reflected by underscoring additions and striking over deletions. This filing requirement is also met by the L series of schedules I previously described.

Q. PLEASE DESCRIBE FR16(8)(l).

A. FR16(8)(l) includes a narrative description and explanation of all proposed tariff changes. This filing requirement is also met by the L series of schedules I previously described.

Q. PLEASE DESCRIBE FR 16(8)(m).

A. FR 16(8)(m) shows the revenue summary for both the base period and the forecasted period with supporting schedules that provide detailed billing analysis for all customer classes. These schedules show the amount of change requested in dollars and the resulting percentage increase for each customer classification and by each rate classification to which the change will apply. In the present case, Duke Energy Kentucky proposes an overall revenue increase including riders of 14.7 percent, which breaks down as previously described. This filing requirement is met by the M series of schedules.

Q. PLEASE DESCRIBE FR 16(8)(n).

A. FR 16(8)(n) shows the typical bill comparison under present and proposed rates for customer classes, current and proposed rates for each customer class, and the rate schedule to which the change would apply. This filing requirement is met by the N schedules previously described.

Q. PLEASE DESCRIBE FR 17(4)(a).

A. FR 17(4)(a) shows the proposed effective date and the date the proposed rates are expected to be filed with the Commission. In this case, the effective date is January 2, 2025, and the dates the proposed rates are expected to be filed is December 2, 2024.

Q. PLEASE DESCRIBE FR 17(4)(b).

A. FR 17(4)(b) shows the present rates and proposed rates for each customer classification to which the proposed rates will apply.

Q. PLEASE DESCRIBE FR 17(4)(c).

A. FR 17(4)(c) shows the amount of the change requested in both dollar amounts and percentage change for each customer classification to which the proposed rates will apply.

Q. PLEASE DESCRIBE FR 17(4)(d).

A. FR17(4)(d) shows the amount of the average usage and the effect on the average bill for each customer classification to which the proposed rates will apply.

Q. PLEASE DESCRIBE FR 17(4)(e) THROUGH (j).

A. FR17(4)(e) through (j) are statements required for inclusion in the Company's notice to customers, including that customers may examine the Company's application at its offices, at the Commission's offices, or on its website. The statements include instructions for submittal of comments to the Commission and that the rates are only proposed and could be changed by the Commission, as well as instructions for intervention. As evidenced by the Company's Notice, Attachment BLS-1, these various statements are included.

III. RETAIL ELECTRIC RATE SCHEDULES AND RIDERS

A. Rate Design and Major Retail Electric Rate Schedules

Q. HOW DID YOU DESIGN THE VARIOUS RATE SCHEDULES IN THIS CASE?

A. I used the cost of service information provided by Duke Energy Kentucky witness James E. Ziolkowski as a basis for the rate design. As more fully described in his testimony, the cost of service information provided for the allocation of costs to the various classes, separation of customer and demand components of cost, and further reduced subsidy/excess revenue by 15 percent. Generally, after assessing customer charge adjustments, I used this information to increase the volumetric charges in each rate schedule in proportion to the revenue recovery under current rates.

Q. PLEASE DESCRIBE ANY OTHER CONSIDERATIONS THAT GUIDED YOUR RATE DESIGN.

A. First, Duke Energy Kentucky supports the general concept that rates charged to core markets, which includes customers in the residential, commercial, industrial, and other public authority classes, should approximate the cost of providing these customers with service. This is because it is intrinsically fair that customers should pay rates that reflect the cost that the utility incurs to provide the service. Duke Energy Kentucky's proposed rates in this case make reasonable movement toward reflecting the cost of service developed and sponsored by Mr. Ziolkowski. As noted above, the revenue requirement from the Cost of Service Study (COSS) is allocated predominately to the demand/energy charges (block steps where applicable) of the rates considering both the current rate design and the new class Cost of Service Study (CCOSS) results. As a first step, customer charges are reviewed and increased as supported by the CCOSS or remain the same if an increase is not supported by the CCOSS. For the residential class, the CCOSS supports a value of $18.97 Recognizing however the concept of gradualism and being mindful of the impact to customers, the Company is proposing to increase the current Rate RS customer charge of $13 to $16.

Second, the Company’s current rate design has served Duke Energy Kentucky customers well and is based on sound rate design principles. Few structural changes in the design of the rates are being proposed in these proceedings. However, the Company does propose to update language in Rates DT and TT for new large loads of 20 MWs or more. This language will require such customers to enter into a service agreement with the Company. This language is discussed separately below.

Q. WHAT ARE THE COMPANY'S MAJOR RETAIL ELECTRIC RATE SCHEDULES?

A. The Company's major retail electric rate schedules include: Rate RS - Residential Service (Rate RS); Rate DS – Service at Secondary Distribution Voltage (Rate DS); Rate DP – Service at Primary Distribution Voltage (Rate DP); Rate DT - Time of Day Rate for Service at Distribution Voltage (Rate DT); and Rate TT – Time of Day Rate for Service at Transmission Voltage (Rate TT). Together, these rate schedules comprise a substantial portion of the Company's retail electric revenue requirement. These rate schedules together are referred to as the "power rate schedules" or "power rates."

Q. HAVE YOU PREPARED RATE SCHEDULES FOR THE POWER RATES?

A. Yes. Again, there are no significant structural changes beyond the items mentioned above for Rates DT and TT. The design objective of the power rates was to collect the revenue requirement while maintaining the existing structural characteristics of the rate schedules. Of note, for Rate DT, a distribution demand charge was established in Case No. 2022-00372. Since this charge is targeted to collect all Rate DT distribution demand revenue from the COSS, the proposed charge uses the COSS distribution demand value directly for calculation. More information on rate calculations can be found below and on Schedule L.

B. New Large Customer Loads

Q. WHAT LANGUAGE DOES THE COMPANY PROPOSE TO ADD TO SHEET NO. 41, RATE DT, TIME-OF-DAY RATE FOR SERVICE AT DISTRIBUTION VOLTAGE, AND SHEET NO. 51, RATE TT, TIME-OF-DAY RATE FOR SERVICE AT TRANSMISSION VOLTAGE?

A. A recent developing industry design concern surrounds the topic of new large loads locating in a service area and claiming service needs that require large, concentrated investments by the local utility. These investments are appropriate when the customer proposed service levels materialize. However, if they do not materialize, other customers may experience significant increases in bills due to an acceleration or over-build of infrastructure. Therefore, for any new loads of 20 MW or more where significant system investments are required, the Company proposes a required service agreement with the customer that will specify credit requirements, minimum demand charges of 75% of the long-term customer projected service need, and associated termination provisions.

Q. WILL THESE NEW SERVICE AGREEMENTS BE SUBJECT TO COMMISSION APPROVAL?

A. Yes. The Company proposes to submit each service agreement to the Commission for approval in a separate proceeding. This agreement may or may not contain provisions related to the Company's economic development programs.

C. Lighting Rates

Q. WHAT CHANGES TO THE COMPANY'S STREET LIGHTING RATES ARE BEING REQUESTED AS PART OF THIS PROCEEDING?

A. Duke Energy Kentucky is proposing to base the increase across all the street lighting rates to recover revenues allocated by the CCOSS. The Company does propose several text changes and new equipment to Rate LED. However, the significant change in lighting rates proposed by the Company is to close Rate OL-E to new Company-owned fixture participation.

Q. PLEASE DESCRIBE THE COMPANY'S RATE DESIGN OBJECTIVES FOR RATE SL – STREET LIGHTING SERVICE; RATE NSU – STREET LIGHTING SERVICE FOR NON-STANDARD UNITS; RATE SC – STREET LIGHTING SERVICE CUSTOMER OWNED; RATE SE – STREET LIGHTING SERVICE, OVERHEAD EQUIVALENT; RATE TL – TRAFFIC LIGHT SERVICE; RATE UOLS – UNMETERED OUTDOOR LIGHTING ELECTRIC SERVICE; AND RATE LED – LED OUTDOOR LIGHTING ELECTRIC SERVICE.

A. The rate design objective for these rate schedules, similar to the other rate classes, is to allocate the increased cost of service revenue requirement to the Distribution Energy & Equipment charges and Pole Rates of the rate schedules. Generally, the Company proposes a proportional increase in all charges in the lighting schedules.

Q. DOES THE COMPANY PROPOSE NEW ITEMS FOR RATE LED?

A. Yes. The charges for the new items are established consistent with the provisions included in Rate LED.

Q. WHAT SUPPORT DOES THE COMPANY PROVIDE FOR THESE NEW ITEMS?

A. Attachment BLS-2 provides the calculation of the levelized fixed charge rates, LFCR, that are used in Confidential Attachment BLS-3 to calculate the monthly charge for the new items.

Q. ARE THERE ADDITIONAL CHANGES TO RATE LED?

A. Yes. Terms and Condition items 14 and 15 are added to provide billing clarity and aid in equipment replacements when facilities reach the end of their useful life.

Q. DOES THE COMPANY PROPOSE CHANGES TO RATE OL-E?

A. Yes. In Sheet Nos. 62, Rate UOLS, and 63, Rate OL-E, the Company adds language to indicate that Rate OL-E will be closed to new participation of Company-owned lighting equipment. This will continue the migration of older Company-owned lighting equipment to Rate LED when the equipment reaches the end of its useful life.

Q. DOES THIS IMPACT THE COMPANY'S REVENUE REQUIREMENT IN THIS CASE?

A. No. Rate OL-E is for "below-the-line" lighting equipment and is not included in the COSS revenue requirement. As these facilities expire, customers will have the option to participate in Rate LED or acquire new lighting equipment in the market. Rate UOLS which provides service for energy to equipment under Rate OL-E remains available to serve customer's lighting needs.

Q. WHAT CHANGES ARE PROPOSED FOR TRAFFIC LIGHTING SERVICE, RATE TL?

A. The Company proposes to change the name of the service to Traffic Signal Service while maintaining the Rate TL designation.

IV. <u>OTHER TARIFF CHANGES</u>

Q. WHAT OTHER TARIFF CHANGES IS THE COMPANY PROPOSING IN THIS CASE?

A. Duke Energy Kentucky is proposing changes to the tariff sheets listed below as well as less significant text changes as captured in Schedule L. Changes to the following sheets are described below.

- Sheet No. 80, Rider FAC, Fuel Adjustment Clause
- Sheet No. 82, Rider PSM, Profit Sharing Mechanism
- Sheet No. 91, Charge for Reconnection of Service
- Sheet No. 92, Distribution Pole Attachments

Q. WHAT CHANGES ARE PROPOSED FOR THE COMPANY'S RIDER FAC, SHEET NO. 80, AND RIDER PSM, SHEET NO. 82?

A. As fully discussed and supported in Ms. Lisa Steinkuhl's testimony, the Company proposes revisions to the Fuel Adjustment Clause (Rider FAC) and Profit Sharing Mechanism (Rider PSM) to include, recover and reconcile various PJM costs and charges not currently being recovered through those mechanisms.

Q. WHAT CHANGES ARE MADE TO THE COMPANY'S CHARGE FOR RECONNECTION OF SERVICE, SHEET NO. 91?

A. In Case No. 2022-00372, the Commission order indicated that the Company should remove labor charges during regular hours from the reconnection charge to customers unless the charge is consistent with vendor costs. Consistent with cost calculations provided in Confidential Attachment BLS-4, the Company proposes to increase the remote reconnection charge to $6.50, decrease the non-remote reconnection charge at the meter to $5.80, and decrease the non-remote reconnection charge at the pole to $16.50. The Company also proposes to eliminate the after-hours charge due to the infrequent need for this charge.

Q. DESCRIBE THE SUPPORT INFORMATION PRESENTED IN CONFIDENTIAL ATTACHMENT BLS-4, CALCULATION OF RECONNECTION FEES.

A. The remote reconnection fee calculation uses a fully loaded labor rate and estimated labor hours to complete a remote reconnection request. The estimated completion times are based on actual historical practice. The file is marked confidential since it also contains vendor pricing. Similarly, non-remote reconnection charges are calculated but without including labor costs. Essentially, the remaining cost is related to the use of the Company's vehicle fleet.

Q. HAS THE COMPANY COMPLETED A POLE ATTACHMENT STUDY AS ORDERED IN CASE NO. 2022-00372?

A. Yes. The Company provides Attachment BLS-5. This attachment provides a similar calculation as presented in past cases and established by the Commission but differing in that it investigates attachment costs for all pole lengths and number of attachments.

Q. CAN YOU SUMMARIZE THE RESULTS OF THIS STUDY?

A. Using the 2-user and 3-user categories, as utilized in the past, and all pole lengths, charges of $7.42 per foot and $7.84 per foot are calculated respectively.

Q. WHAT DOES THE COMPANY PROPOSE FROM THE RESULTS OF THE STUDY?

A. Using all pole lengths converges the 2-user and 3-user charges. The Company proposes that it is reasonable and simplifies administration if the two categories are combined into one charge per foot for all pole attachments. The single charge proposed by the Company is $7.50 as calculated in Attachment BLS-5.

Q. WHAT SUPPORT DOES THE COMPANY PROVIDE FOR THE CALCULATION OF THE PROPOSED CONDUIT FEE?

A. Using FERC Form 1 and other Company data, Attachment BLS-6 is provided to support the calculation of the proposed conduit fee.

Q. ARE ANY CUSTOMERS CURRENTLY OCCUPYING COMPANY CONDUIT SPACE AND CHARGED THE PROPOSED FEE?

A. At this time, no customers are occupying Company conduit space and being charged the associated fee.

V. CONCLUSION

Q. HOW DOES THE COMPANY PROPOSE THAT ITS TARIFFS, INCLUDING THE PREVIOUSLY DISCUSSED RATES AND CHARGES, BE IMPLEMENTED?

A. We propose that the revised tariff, including the rates and charges complying with the Commission's order in this Case, be established effective January 2, 2025, for all customers.

Q. WERE SCHEDULES L, L-1, L-2.1, L-2.2, M, M-2.1 THROUGH M-2.3 AND N AS WELL AS, FR 16(1)(b)(3), FR 16(1)(b)(4), FR 16(8)(l), FR 16(8)(m), FR 16(8)(n), FR 17(4), AND ATTACHMENTS BLS-1, BLS-2, BLS-5, BLS-6, AND CONFIDENTIAL ATTACHMENTS BLS-3 AND BLS-4, PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. IS THE INFORMATION CONTAINED IN THOSE SCHEDULES AND FILING REQUIREMENTS ACCURATE TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

NOTICE

Duke Energy Kentucky, Inc. ("Duke Energy Kentucky" or "Company") hereby gives notice that, in an application to be filed no sooner than December 2, 2024, 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 2, 2025. The Commission has docketed this proceeding as Case No. 2024-00354.

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

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

	Current Rate	Proposed Rate
Customer Charge per month	$13.00	$16.00
Energy Charge per kWh		
All kWh	11.1639¢	13.0111¢

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	$10.68	$12.36
Energy Charge per kWh		
First 6,000 kWh	11.4788¢	13.2874¢
Next 300 kWh/kW	7.4619¢	8.6376¢
Additional kWh	6.3056¢	7.2989¢
Non-Church Cap Rate per kWh	30.7297¢	35.5714¢
Church Cap Rate per kWh	18.8652¢	21.8386¢

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	$64.00	$64.00
Three Phase Service	$127.00	$127.00	$128.00	$128.00
Primary Voltage Service	$138.00	$138.00	$160.00	$160.00
Demand Charge per kW				
On Peak kW	$14.71	$13.92	$16.73	$15.83
Off Peak kW	$1.32	$1.32	$1.50	$1.50
Distribution kW	$6.07	$6.07	$7.77	$7.77
Energy Charge per kWh				
On Peak kWh	5.6747¢	5.4640¢	6.4528¢	6.2133¢
Off Peak kWh	4.8348¢	4.8348¢	5.4976¢	5.4976¢
Metering per kW				
First 1,000 kW On Peak	($0.75)	($0.75)	($0.85)	($0.85)
Additional kW On Peak	($0.58)	($0.58)	($0.66)	($0.66)

Current Demand:
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.

Proposed Demand:
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. On-peak, Off-peak, and distribution demand values are subject to applicable minimum requirements as established in a service agreement between the Customer and the Company as described below under Terms and Conditions.

Proposed Addition to Terms and Conditions:
Customers seeking service of 20 MW or greater at one or more aggregated premises, or whose demand is reasonably expected to grow to this level, and require significant production and/or transmission investments by the Company for the provision of service may be required to provide the Company appropriate financial and/or performance and credit assurance. A minimum demand provision equal to 75% of the customer specified load requirement and credit requirements will be specified in a required service agreement between the Customer and the Company. The service agreement is subject to Commission approval.

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	$120.00
Energy Charge per kWh		
All kWh	9.0636¢	10.4834¢

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	14.4519¢	16.7645¢

Optional Unmetered General Service Rate
For Small Fixed Loads – 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)	11.5594¢	13.3002¢
For loads of less than 540 hours use per month of the rated capacity of the connected equipment (per kWh)	13.1566¢	15.1636¢
Minimum per month	$3.79	$4.37

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	$120.00
Demand Charge per kW		
All kW	$9.50	$10.13
Energy Charge per kWh		
First 300 kWh/kW	7.1562¢	7.6294¢
Additional kWh	6.2068¢	6.6112¢
Maximum monthly rate per kWh (excluding customer charge and all applicable riders)	28.9184¢	30.8166¢

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	$9.41	$7.72	$10.23	$8.39
Off Peak kW	$1.43	$1.43	$1.55	$1.55
Energy Charge per kWh				
On Peak kWh	6.7652¢	6.5057¢	7.3558¢	7.0736¢
Off Peak kWh	5.7296¢	5.7296¢	6.2297¢	6.2297¢

Current Demand:
In no case shall the Off Peak billing demand be less than zero.

Proposed Demand:
In no case shall the Off Peak billing demand be less than zero. On-peak and Off-peak demand values are subject to applicable minimum requirements as established in a service agreement between the Customer and the Company as described below under Terms and Conditions.

Proposed Addition to Terms and Conditions:
Customers seeking service of 20 MW or greater at one or more aggregated premises, or whose demand is reasonably expected to grow to this level, and require significant production and/or transmission investments by the Company for the provision of service may be required to provide the Company appropriate financial and/or performance and credit assurance. A minimum demand provision equal to 75% of the customer specified load requirement and credit requirements will be specified in a required service agreement between the Customer and the Company. The service agreement is subject to Commission approval.

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	$6.209222	$10.036170
Rate DT Distribution Service	$7.855088	$13.808205
Rate DP Primary Distribution	$8.173019	$7.042203
Rate TT Transmission Service	$3.267552	$5.243274

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	$11.49	$13.13
7,000 lumen (Open Refractor)	175	0.205	853	$9.77	$11.16
10,000 lumen	250	0.275	1,144	$13.47	$15.39
21,000 lumen	400	0.430	1,789	$18.27	$20.88
Metal Halide					
14,000 lumen	175	0.193	803	$11.49	$13.13
20,500 lumen	250	0.275	1,144	$13.47	$15.39
36,000 lumen	400	0.430	1,789	$18.27	$20.88
Sodium Vapor					
9,500 lumen	100	0.117	487	$12.34	$14.10
9,500 lumen (Open Refractor)	100	0.117	487	$9.38	$10.72
16,000 lumen	150	0.171	711	$13.64	$15.59
22,000 lumen	200	0.228	948	$17.70	$20.22
27,500 lumen	250	0.275	948	$17.70	$20.22
50,000 lumen	400	0.471	1,959	$24.43	$27.91
Decorative Fixtures					
Sodium Vapor					
9,500 lumen (Rectilinear)	100	0.117	487	$15.24	$17.41
22,000 lumen (Rectilinear)	200	0.246	1,023	$19.22	$21.96

50,000 lumen (Rectilinear)	400	0.471	1,959	$26.01	$29.72
50,000 lumen (Setback)	400	0.471	1,959	$37.80	$43.19
Spans of Secondary Wiring (per month for each increment of 50 feet of secondary wiring beyond the first 150 feet from the pole)				$0.76	$0.87

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	$11.74	$13.41
7,000 lumen (Open Refractor)	175	0.205	853	$9.77	$11.16
10,000 lumen	250	0.292	1,215	$13.76	$15.72
21,000 lumen	400	0.460	1,914	$18.80	$21.48
Metal Halide					
14,000 lumen	175	0.210	874	$11.74	$13.41
20,500 lumen	250	0.292	1,215	$13.76	$15.72
36,000 lumen	400	0.460	1,914	$18.80	$21.48
Sodium Vapor					
9,500 lumen	100	0.117	487	$12.34	$14.10
9,500 lumen (Open Refractor)	100	0.117	487	$9.51	$10.87
16,000 lumen	150	0.171	711	$13.60	$15.54
22,000 lumen	200	0.228	948	$17.70	$20.22
27,500 lumen	250	0.318	1,323	$18.04	$20.61
50,000 lumen	400	0.471	1,959	$24.43	$27.91
Decorative Fixtures					
Mercury Vapor					
7,000 lumen (Town & Country)	175	0.205	853	$12.11	$13.84
7,000 lumen (Holphane)	175	0.210	874	$15.01	$17.15
7,000 lumen (Gas Replica)	175	0.210	874	$33.30	$38.05
7,000 lumen (Granville)	175	0.205	853	$12.23	$13.97
7,000 lumen (Aspen)	175	0.210	874	$21.39	$24.44
Metal Halide					
14,000 lumen (Traditionaire)	175	0.205	853	$12.09	$13.81
14,000 lumen (Granville Acorn)	175	0.210	874	$21.39	$24.44
14,000 lumen (Gas Replica)	175	0.210	874	$33.42	$38.19
14,500 lumen (Gas Replica)	175	0.207	861	$33.41	$38.17
Sodium Vapor					
9,500 lumen (Town & Country)	100	0.117	487	$16.97	$19.39
9,500 lumen (Holophane)	100	0.128	532	$18.39	$21.01
9,500 lumen (Rectiliinear)	100	0.117	487	$13.96	$15.95
9,500 lumen (Gas Replica)	100	0.128	532	$35.23	$40.25
9,500 lumen (Aspen)	100	0.128	532	$21.34	$24.38
9,500 lumen (Traditionaire)	100	0.117	487	$16.97	$19.39
9,500 lumen (Granville Acorn)	100	0.128	532	$21.34	$24.38
22,000 lumen (Rectilinear)	200	0.246	1,023	$19.32	$22.08
50,000 lumen (Rectilinear)	400	0.471	1,959	$26.10	$29.82
50,000 lumen (Setback)	400	0.471	1,959	$37.80	$43.19

Pole Charges	Pole Type	Current Rate/Pole	Proposed Rate/Pole
Wood			
17 foot (Wood laminated)	W17	$6.25	$7.14
30 foot	W30	$6.17	$7.05
35 foot	W35	$6.25	$7.14
40 foot	W40	$7.48	$8.55
Aluminum			
12 foot (decorative)	A12	$16.98	$19.40

28 foot	A28	$9.84	$11.24
28 foot (heavy duty)	A28H	$9.95	$11.37
30 foot (anchor base)	A30	$19.66	$22.46
Fiberglass			
17 foot	F17	$6.25	$7.14
12 foot (decorative)	F12	$18.26	$20.86
30 foot (bronze)	F30	$11.88	$13.57
35 foot (bronze)	F35	$12.21	$13.95
Steel			
27 foot (11 gauge)	S27	$16.05	$18.34
27 foot (3 gauge)	S27H	$23.69	$27.07
Spans of Secondary Wiring (per month for each increment of 25 feet of secondary wiring beyond the first 25 feet from the pole		$1.10	$1.26

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

	Current Rate	Proposed Rate
Where the Company supplies energy only (per kWh)	6.7222¢	7.6809¢

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

	Current Rate	Proposed Rate
Energy Charge per kWh		
All kWh	6.6467¢	7.5946¢

Proposed Addition to Applicability:
This rate schedule is no longer available after June 30, 2025 to new participation of Company-owned equipment under Rate OL-E. Existing Company-owned systems under Rate OL-E currently being provided service under this tariff schedule may continue being provided service under this tariff schedule until the Company-owned system under Rate OL-E is no longer provided under Rate OL-E.

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

Proposed Addition to Applicability:
This rate schedule is no longer available after June 30, 2025. 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. This rate schedule will terminate on June 30, 2045.

Current Contract for Service:
The monthly Maintenance Charge does not cover replacement of the fixture upon failure.

Proposed Contract for Service:
See General Conditions below.

Proposed Addition of General Conditions:
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.

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

	Current Rate	Proposed Rate
Energy Charge per kWh		
All kWh	6.9217¢	7.9088¢

Rates (Per Unit Per Month)

Fixtures Description	Initial Lumens	Lamp Wattage	Monthly kWh	Current Charge Fixture	Current Charge Maint.	Proposed Charge Fixture	Proposed Charge Maint.
50W Neighborhood	5,000	50	17	$4.15	$2.90	$4.74	$3.31
50W Neighborhood with Lens	5,000	50	17	$4.20	$2.90	$4.80	$3.31
50W Standard LED-BLACK	4,521	50	17	$3.84	$2.90	$4.39	$3.31
70W Standard LED-BLACK	6,261	70	24	$4.22	$2.90	$4.82	$3.31
110W Standard LED-BLACK	9,336	110	38	$4.77	$2.90	$5.45	$3.31
150W Standard LED-BLACK	12,642	150	52	$4.83	$2.90	$5.52	$3.31
220W Standard LED-BLACK	18,642	220	76	$6.31	$3.54	$7.21	$4.04
280W Standard LED-BLACK	24,191	280	97	$6.36	$3.54	$7.27	$4.04
50W Acorn LED-BLACK	5,147	50	17	$11.71	$2.90	$13.38	$3.31
50W Deluxe Acorn LED-BLACK	5,147	50	17	$13.05	$2.90	$14.91	$3.31
70W LED Open Deluxe Acorn	6,500	70	24	$13.44	$2.90	$15.36	$3.31
50W Traditional LED-BLACK	3,303	50	17	$6.31	$2.90	$7.21	$3.31
50W Open Traditional LED-BLACK	3,230	50	17	$6.56	$2.90	$7.50	$3.31
50W Mini Bell LED-BLACK	4,500	50	17	$12.01	$2.90	$13.72	$3.31
50W Enterprise LED-BLACK	3,880	50	17	$11.53	$2.90	$13.17	$3.31
70W Sanibel LED-BLACK	5,508	70	24	$14.66	$2.90	$16.75	$3.31
150W Sanibel	12,500	150	52	$15.28	$2.90	$17.46	$3.31
150W LED Teardrop	12,500	150	52	$18.36	$2.90	$20.98	$3.31
50W LED Teardrop Pedestrian	4,500	50	17	$15.01	$2.90	$17.15	$3.31
220W LED Shoebox	18,500	220	76	$11.39	$3.54	$13.01	$4.04
420W LED Shoebox	39,078	420	146	$16.92	$3.54	$19.33	$4.04
530W LED Shoebox	57,000	530	184	$19.49	$3.54	$22.27	$4.04
150W Clermont LED	12,500	150	52	$20.04	$2.90	$22.90	$3.31
130W Flood LED	14,715	130	45	$7.20	$2.90	$8.23	$3.31
260W Flood LED	32,779	260	90	$11.24	$3.54	$12.84	$4.04
50W Monticello LED	4,157	50	17	$13.49	$2.90	$15.41	$3.31
50W Mitchell Finial	5,678	50	17	$12.85	$2.90	$14.68	$3.31
50W Mitchell Ribs, Bands, and Medallions LED	5,678	50	17	$14.04	$2.90	$16.04	$3.31
50W Mitchell Top Hat LED	5,678	50	17	$12.85	$2.90	$14.68	$3.31
50W Mitchell Top Hat with Ribs, Bands, & Medallions LED	5,678	50	17	$14.04	$2.90	$16.04	$3.31
50W Open Monticello LED	4,157	50	17	$13.44	$2.90	$15.36	$3.31
150W LED Shoebox	19,000	150	52	$10.48	$2.90	$11.97	$3.31
50W Sanibel LED	6,000	50	17	$13.90	$2.90	$15.88	$3.31
40W Acorn No Finial LED	5,000	40	14	$11.20	$2.90	$12.80	$3.31
50W Ocala Acorn LED	6,582	50	17	$6.71	$2.90	$7.67	$3.31
50W Deluxe Traditional LED	5,057	50	17	$12.82	$2.90	$14.65	$3.31
30W Town & Country LED	3,000	30	10	$5.35	$2.90	$6.11	$3.31
30W Open Town & Country LED	3,000	30	10	$5.09	$2.90	$5.82	$3.31
150W Enterprise LED	16,500	150	52	$11.45	$2.90	$13.08	$3.31
220W Enterprise LED	24,000	220	76	$11.78	$3.54	$13.46	$4.04
50W Clermont LED	6,300	50	17	$18.68	$2.90	$21.34	$3.31
30W Gaslight Replica LED	3,107	30	10	$21.30	$2.90	$24.34	$3.31
50W Cobra LED	5,500	50	17	$4.17	$2.90	$4.76	$3.31
70W Cobra LED	8,600	70	24	$4.33	$2.90	$4.95	$3.31
30W Granville Acorn LED	4,100	30	10	N/A	N/A	$11.75	$3.31

30W Style B Bollard LED	2,390	30	10	N/A	N/A	$15.31	$3.31
30W Style C Bollard LED	2,146	30	10	N/A	N/A	$15.31	$3.31
30W Style D Bollard LED	2,390	30	10	N/A	N/A	$15.31	$3.31
30W Style E Bollard LED	1,200	30	10	N/A	N/A	$15.31	$3.31
40W Colonial Bollard LED	1,107	40	14	N/A	N/A	$19.48	$3.31
40W Washington Bollard LED	1,107	40	14	N/A	N/A	$19.48	$3.31
26W Holiday Riser Receptacle LED	NA	26	9	N/A	N/A	$4.21	$3.31
26W Holiday Bracket Top Receptacle LED	NA	26	9	N/A	N/A	$4.96	$3.31
26W Holiday Festoon Receptacle LED	NA	26	9	N/A	N/A	$5.85	$3.31
26W Holiday Post Top Receptacle LED	NA	26	9	N/A	N/A	$5.32	$3.31
26W Holiday Post Top with Adapter Receptacle LED	NA	26	9	N/A	N/A	$5.91	$3.31
26W Dual Post Top Receptacle LED	NA	26	9	N/A	N/A	$6.94	$3.31
26W Dual Post Top with Adapter Receptacle LED	NA	26	9	N/A	N/A	$7.53	$3.31
26W Dual Bracket Top Receptacle LED	NA	26	9	N/A	N/A	$6.94	$3.31
50W Senoia LED	4,525	50	17	N/A	N/A	$15.68	$3.31
50W Halo LED	4,809	50	17	N/A	N/A	$17.64	$3.31
30W Standard LED	3,720	30	10	N/A	N/A	$3.17	$3.31
40W Standard LED	4,506	40	14	N/A	N/A	$3.18	$3.31
30W Gray Open Bottom LED	4,510	30	10	N/A	N/A	$3.06	$3.31

Poles

Description	Current Charge	Proposed Charge
Style A 12 Ft Long Anchor Base Top Tenon Aluminum	$9.34	$10.67
Style A 15 Ft Long Direct Buried Top Tenon Aluminum	$8.69	$9.93
Style A 15 Ft Long Anchor Base Top Tenon Aluminum	$10.83	$12.37
Style A 18 Ft Long Direct Buried Top Tenon Aluminum	$8.90	$10.17
Style A 17 Ft Long Anchor Base Top Tenon Aluminum	$11.55	$13.20
Style A 25 Ft Long Direct Buried Top Tenon Aluminum	$11.75	$13.43
Style A 22 Ft Long Anchor Base Top Tenon Aluminum	$14.57	$16.65
Style A 30 Ft Long Direct Buried Top Tenon Aluminum	$13.35	$15.25
Style A 27 Ft Long Anchor Base Top Tenon Aluminum	$19.48	$22.26
Style A 35 Ft Long Direct Buried Top Tenon Aluminum	$15.49	$17.70
Style A 32 Ft Long Anchor Base Top Tenon Aluminum	$19.99	$22.84
Style A 41 Ft Long Direct Buried Top Tenon Aluminum	$18.98	$21.69
Style B 12 Ft Long Anchor Base Post Top Aluminum	$10.61	$12.12
Style C 12 Ft Long Anchor Base Post Top Aluminum	$12.91	$14.75
Style C 12 Ft Long Anchor Base Davit Steel	$15.64	$17.87
Style C 14 Ft Long Anchor Base Top Tenon Steel	$14.75	$16.85
Style C 21 Ft Long Anchor Base Davit Steel	$32.96	$37.66
Style C 23 Ft Long Anchor Base Boston Harbor Steel	$38.27	$43.73
Style D 12 Ft Long Anchor Base Breakaway Aluminum	$12.32	$14.08
Style E 12 Ft Long Anchor Base Post Top Aluminum	$12.91	$14.75
Style F 12 Ft Long Anchor Base Post Top Aluminum	$15.74	$17.98
Legacy Style 39 Ft Direct Buried Single or Twin Side Mount Alum Satin Finish	$20.92	$23.90
Legacy Style 27 Ft Long Anchor Base Side Mnt Alum Satin Finish Breakaway	$20.45	$23.37
Legacy Style 33 Ft Long Anchor Base Side Mnt Alum Satin Finish Breakaway	$21.38	$24.43
Legacy Style 37 Ft Long Anchor Base Side Mount Aluminum Pole Satin Finish	$23.61	$26.98
30' Class 7 Wood Pole	$6.48	$7.40
35' Class 5 Wood Pole	$7.24	$8.27
40' Class 4 Wood Pole	$8.21	$9.38
45' Class 4 Wood Pole	$8.55	$9.77
15' Style A - Fluted - for Shroud - Aluminum Direct Buried Pole	$10.05	$11.48
20' Style A - Fluted - for Shroud - Aluminum Direct Buried Pole	$10.54	$12.04
15' Style A - Smooth - for Shroud - Aluminum Direct Buried Pole	$8.69	$9.93
20' Style A - Smooth - for Shroud - Aluminum Direct Buried Pole	$10.26	$11.72
21' Style A - Fluted - Direct Buried	$14.37	$16.42
30' Style A - Transformer Base - Anchor Base	$21.78	$24.89

35' Style A - Transformer Base - Anchor Base	$24.53	$28.03
19' Style A - Breakaway - Direct Buried	$19.55	$22.34
24' Style A - Breakaway - Direct Buried	$20.69	$23.64
27' Style A - Breakaway - Direct Buried	$19.79	$22.61
32' Style A - Breakaway - Direct Buried	$20.26	$23.15
37' Style A - Breakaway - Direct Buried	$21.56	$24.63
42' Style A - Breakaway - Direct Buried	$22.29	$25.47
17' Style B - Anchor Base	$15.04	$17.18
17' Style C - Post Top - Anchor Base	$16.22	$18.53
17' Style C - Davit - Anchor Base	$25.65	$29.31
17' Style C - Boston Harbor - Anchor Base	$25.02	$28.59
25' Style D - Boston Harbor - Anchor Base	$29.17	$33.33
50' Wood - Direct Buried	$10.64	$12.16
55' Wood - Direct Buried	$11.21	$12.81
18' Style C - Breakaway - Direct Buried	$22.18	$25.34
17’ Wood Laminated	$6.25	$7.14
12’ Aluminum (decorative)	$16.98	$19.40
28’ Aluminum	$9.84	$11.24
28’ Aluminum (heavy duty)	$9.95	$11.37
30’ Aluminum (anchor base)	$19.66	$22.46
17’ Fiberglass	$6.25	$7.14
12’ Fiberglass (decorative)	$18.26	$20.86
30’ Fiberglass (bronze)	$11.88	$13.57
35’ Fiberglass (bronze)	$12.21	$13.95
27’ Steel (11 gauge)	$16.05	$18.34
27’ Steel (3 gauge)	$23.69	$27.07
Shroud - Standard Style for anchor base poles	$2.71	$3.10
Shroud - Style B Pole for smooth and fluted poles	$6.44	$7.36
Shroud - Style C Pole for smooth and fluted poles	$8.05	$9.20
Shroud - Style D Pole for smooth and fluted poles	$9.93	$11.35
Shroud - Style B – Assembly	$8.42	$9.62
Shroud - Style C – Assembly	$9.89	$11.30
Shroud - Style D – Assembly	$12.06	$13.78
Shroud - Style Standard - Assembly 6"/15"	$4.71	$5.38
Shroud - Style Standard - Assembly 6"/18"	$5.12	$5.85

Pole Foundation

Description	Current Charge	Proposed Charge
Flush - Pre-fabricated - Style A Pole	$13.30	$15.20
Flush - Pre-fabricated - Style B Pole	$12.28	$14.03
Flush - Pre-fabricated - Style C Pole	$13.17	$15.05
Flush - Pre-fabricated - Style D Pole	$12.28	$14.03
Flush - Pre-fabricated - Style E Pole	$12.28	$14.03
Flush - Pre-fabricated - Style F Pole	$12.28	$14.03
Reveal - Pre-fabricated - Style A Pole	$18.73	$21.40
Reveal - Pre-fabricated - Style B Pole	$14.90	$17.02
Reveal - Pre-fabricated - Style C Pole	$15.46	$17.66
Reveal - Pre-fabricated - Style D Pole	$15.46	$17.66
Reveal - Pre-fabricated - Style E Pole	$15.46	$17.66
Reveal - Pre-fabricated - Style F Pole	$15.46	$17.66
Screw-in Foundation	$7.96	$9.10

Brackets

Description	Current Charge	Proposed Charge
14 inch bracket - wood pole - side mount	$1.93	$2.21
4 foot bracket - wood pole - side mount	$2.16	$2.47
6 foot bracket - wood pole - side mount	$2.13	$2.43

8 foot bracket - wood pole - side mount	$2.89	$3.30
10 foot bracket - wood pole - side mount	$4.77	$5.45
12 foot bracket - wood pole - side mount	$4.34	$4.96
15 foot bracket - wood pole - side mount	$5.07	$5.79
4 foot bracket - metal pole - side mount	$5.14	$5.87
6 foot bracket - metal pole - side mount	$5.21	$5.95
8 foot bracket - metal pole - side mount	$6.47	$7.39
10 foot bracket - metal pole - side mount	$6.82	$7.79
12 foot bracket - metal pole - side mount	$6.23	$7.12
15 foot bracket - metal pole - side mount	$7.44	$8.50
18 inch bracket - metal pole - double Flood Mount - top mount	$2.07	$2.37
14 inch bracket - metal pole - single mount - top tenon	$2.19	$2.50
14 inch bracket - metal pole - double mount - top tenon	$2.37	$2.71
14 inch bracket - metal pole - triple mount - top tenon	$2.52	$2.88
14 inch bracket - metal pole - quad mount - top tenon	$2.63	$3.01
6 foot - metal pole - single - top tenon	$4.87	$5.56
6 foot - metal pole - double - top tenon	$6.17	$7.05
4 foot - Boston Harbor - top tenon	$7.06	$8.07
6 foot - Boston Harbor - top tenon	$7.43	$8.49
12 foot - Boston Harbor Style C pole double mount - top tenon	$12.71	$14.52
4 foot - Davit arm - top tenon	$6.44	$7.36
18 inch - Cobrahead fixture for wood pole	$1.82	$2.08
18 inch - Flood light for wood pole	$2.01	$2.30
18" Metal - Flood - Bullhorn - Top Tenon	$2.48	$2.83
4' Transmission - Top Tenon	$9.12	$10.42
10' Transmission - Top Tenon	$10.51	$12.01
15' Transmission - Top Tenon	$11.56	$13.21
18" Transmission - Flood - Top Tenon	$4.86	$5.55
3' Shepherds Crook - Single - Top Tenon	$4.61	$5.27
3' Shepherds Crook w/ Scroll - Single - Top Tenon	$5.11	$5.84
3' Shepherds Crook - Double - Top Tenon	$6.52	$7.45
3' Shepherds Crook w/ Scroll - Double - Top Tenon	$7.33	$8.38
3' Shepherds Crook w/ Scroll & Festoon - Single - Top Tenon	$5.35	$6.11
3' Shepherds Crook w/ Scroll - Wood - Top Tenon	$6.38	$7.29
17" Masterpiece - Top Tenon - Double Post Mount - Top Tenon	$5.09	$5.82

Wiring Equipment

Description	Current Charge	Proposed Charge
Secondary Pedestal (cost per unit)	$2.47	$2.82
Handhole (cost per unit)	$3.54	$4.04
Pullbox	$8.98	$10.26
6AL DUPLEX and Trench (cost per foot)	$1.12	$1.28
6AL DUPLEX and Trench with conduit (cost per foot)	$1.30	$1.49
6AL DUPLEX with existing conduit (cost per foot)	$0.82	$0.94
6AL DUPLEX and Bore with conduit (cost per foot)	$2.79	$3.19
6AL DUPLEX OH wire (cost per foot)	$2.62	$2.99

Sheilds

Description	Current Charge	Proposed Charge
Standard	N/A	$1.83
Decorative	N/A	$1.71

Additional Facilities Charge	0.8292%	0.8642%

Current Wiring Equipment Description:

6AL DUPLEX and Trench (cost per foot)
6AL DUPLEX and Trench with conduit (cost per foot)

6AL DUPLEX with existing conduit (cost per foot)
6AL DUPLEX and Bore with conduit (cost per foot)
6AL DUPLEX OH wire (cost per foot)

Proposed Wiring Equipment Description:
6AL DUPLEX and Trench (cost per 10 feet)
6AL DUPLEX and Trench with conduit (cost per 10 feet)
6AL DUPLEX with existing conduit (cost per 10 feet)
6AL DUPLEX and Bore with conduit (cost per 10 feet)
6AL DUPLEX OH wire (cost per 10 feet)

Current Terms of Service:

13. For available LEDs, the customer may opt to make an initial, one-time payment of 50% of the installed cost of fixtures rated greater than 200 Watts and poles other than standard wood poles, to reduce the Company's installed cost, therefore reducing their monthly rental rates for such fixtures and poles. If a customer chooses this option, the monthly fixture and/or pole charge shall be computed as the reduced installed cost times the corresponding monthly percentage in 2.I.(a) and/or 2.II above.

Proposed Terms of Service:

13. The customer may opt to make an initial, upfront one-time payment of 50% of the installed cost of the equipment in the lighting system to reduce the Company's installed cost, therefore reducing the Customer's ongoing monthly equipment charge by 50% of the current tariff price over the fixed term for the life of the equipment.

14. Outage credits do not apply to Rate LED.
15. 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 lighting unit on Rate LED and the Customer shall commence being billed for the available similar lighting unit and will enter into a new lighting agreement within 90 days. The terms of service of Rate LED shall commence upon lighting unit installation. If within 90 days of replacement the Customer does not enter into a new agreement, the service may be terminated.

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

Company Owned	Lamp Watts	kW/ Unit	Annual kW/unit	Current Rate/Unit	Proposed Rate/Unit
Boulevard units served underground					
a. 2,500 lumen Incandescent – Series	148	0.148	616	$14.51	$16.58
b. 2,500 lumen Incandescent – Multiple	189	0.189	786	$11.56	$13.21
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	$26.51	$30.29
Each increment of 25 feet of secondary wiring beyond the first 25 feet from the pole base (added to Rate/unit charge)				$1.10	$1.26
Street light units served overhead distribution					
a. 2,500 lumen Incandescent	189	0.189	786	$11.46	$13.09
b. 2,500 lumen Mercury Vapor	100	0.109	453	$10.58	$12.09
c. 21,000 lumen Mercury Vapor	400	0.460	1,914	$17.87	$20.42
Customer Owned					
Steel boulevard units served underground with limited maintenance by Company					
a. 2,500 lumen Incandescent – Series	148	0.148	616	$8.79	$10.04
b. 2,500 lumen Incandescent – Multiple	189	0.189	786	$11.18	$12.77

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

Base Rate Fixture Description	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	$6.80	$7.77
10,000 lumen	250	0.275	1,144	$8.80	$10.05
21,000 lumen	400	0.430	1,789	$12.41	$14.18
Metal Halide					
14,000 lumen	175	0.193	803	$6.80	$7.77
20,500 lumen	250	0.275	1,144	$8.80	$10.05
36,000 lumen	400	0.430	1,789	$12.41	$14.18
Sodium Vapor					
9,500 lumen	100	0.117	487	$7.67	$8.76
16,000 lumen	150	0.171	711	$8.73	$9.97
22,000 lumen	200	0.228	948	$9.77	$11.16
27,500 lumen	250	0.228	948	$9.77	$11.16
50,000 lumen	400	0.471	1,959	$13.96	$15.95
Decorative Fixture					
Mercury Vapor					
7,000 lumen (Holophane)	175	0.210	874	$8.49	$9.70
7,000 lumen (Town & Country)	175	0.205	853	$8.40	$9.60
7,000 lumen (Gas Replica)	175	0.210	874	$8.49	$9.70
7,000 lumen (Aspen)	175	0.210	874	$8.49	$9.70
Metal Halide					
14,000 lumen (Traditionaire)	175	0.205	853	$8.40	$9.60
14,000 lumen (Granville Acorn)	175	0.210	874	$8.56	$9.78
14,000 lumen (Gas Replica)	175	0.210	874	$8.56	$9.78
Sodium Vapor					
9,500 lumen (Town & Country)	100	0.117	487	$7.56	$8.64
9,500 lumen (Traditionaire)	100	0.117	487	$7.56	$8.64
9,500 lumen (Granville Acorn)	100	0.128	532	$7.91	$9.04
9,500 lumen (Rectilinear)	100	0.117	487	$7.56	$8.64
9,500 lumen (Aspen)	100	0.128	532	$7.91	$9.04
9,500 lumen (Holophane)	100	0.128	532	$7.91	$9.04
9,500 lumen (Gas Replica)	100	0.128	532	$7.91	$9.04
22,000 lumen (Rectilinear)	200	0.246	1,023	$10.36	$11.84
50,000 lumen (Rectilinear)	400	0.471	1,959	$14.38	$16.43

Pole Description	Pole Type	Current Rate/Pole	Proposed Rate/Pole
Wood			
30 foot	W30	$ 6.17	$7.05
35 foot	W35	$ 6.25	$7.14
40 foot	W40	$ 7.48	$8.55

Customer Owned and Maintained Units	**Current per kWh**	Proposed per kWh
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.	6.6038¢	7.5456¢

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

Fixture Description	Lamp Watt	kW/Unit	Annual kWh	Current Rate/Unit	Proposed Rate/Unit
Decorative Fixtures					
Mercury Vapor					
7,000 lumen (Town & Country)	175	0.205	853	$11.78	$13.46
7,000 lumen (Holophane)	175	0.210	874	$11.83	$13.52
7,000 lumen (Gas Replica)	175	0.210	874	$11.83	$13.52
7,000 lumen (Aspen)	175	0.210	874	$11.83	$13.52
Metal Halide					
14,000 lumen (Traditionaire)	175	0.205	853	$11.78	$13.46
14,000 lumen (Granville Acorn)	175	0.210	874	$11.83	$13.52
14,000 lumen (Gas Replica)	175	0.210	874	$11.83	$13.52
Sodium Vapor					
9,500 lumen (Town & Country)	100	0.117	487	$12.41	$14.18
9,500 lumen (Holophane)	100	0.128	532	$12.63	$14.43
9,500 lumen (Rectilinear)	100	0.117	487	$12.41	$14.18
9,500 lumen (Gas Replica)	100	0.128	532	$12.62	$14.42
9,500 lumen (Aspen)	100	0.128	532	$12.62	$14.42
9,500 lumen (Traditionaire)	100	0.117	487	$12.41	$14.18
9,500 lumen (Granville Acorn)	100	0.128	532	$12.62	$14.42
22,000 lumen (Rectilinear)	200	0.246	1,023	$18.14	$20.73
50,000 lumen (Rectilinear)	400	0.471	1,959	$24.58	$28.09
50,000 lumen (Setback)	400	0.471	1,959	$24.58	$28.09

Demand Side Management Cost Recovery Rider
(Electric Tariff Sheet No. 75)

Current Applicability:
Applicable to service rendered under the provisions of Rates RS and RS-TOU-CPP (residential class), DS, DP, DT, EH, GS-FL, SP, and TT (non-residential class).

Proposed Applicability:
Applicable to service rendered under the provisions of Rate RS (residential class), DS, DP, DT, EH, GS-FL, SP, and TT (non-residential class).

Fuel Adjustment Clause Rider
(Electric Tariff Sheet No. 80)

Current Availability of Service Item (e):

(e) The native portion of fuel-related costs charged to the Company by PJM Interconnection LLC includes those costs identified in the following Billing Line Items, as may be amended from time to time by PJM Interconnection LLC: Billing Line Items 1210, 2210, 1215, 1218, 2217, 2218, 1230, 1250, 1260, 2260, 1370, 2370, 1375, 2375, 1400, 1410, 1420, 1430, 1478, 1340, 2340, 1460, 1350, 2350, 1360, 2360, 1470, 1377, 2377, 1480, 1378, 2378, 1490, 1500, 2420, 2220, 1200, 1205, 1220, 1225, 2500, 2510, 1930, 2211, 2215, 2415 and 2930.

.

The Company proposes to revise the list of PJM Interconnection LLC Billing Line Items as follows.
Proposed Availability of Service Item (e):

(e) The native portion of fuel-related costs charged to the Company by PJM Interconnection LLC includes those costs identified in the following Billing Line Items, as may be amended from time to time by PJM Interconnection LLC: Billing Line Items 1210, 1215, 1216, 1218, 2217, 2218, 1230, 1250, 1260, 2260, 1370, 2370, 1375, 2375, 1400, 1410, 1420, 1430, 1478, 1340, 2340, 1460, 1350, 2350, 1360, 2360, 2366, 1470, 1377, 2377, 1480, 1378, 2378, 1490, 1500, 2420, 2220, 1200, 1205, 1220, 1225, 2500, 2510, 1930, 2211, 2215, 2415, 2930, 1980, 2980 and 1999.

Profit Sharing Mechanism Rider
(Electric Tariff Sheet No. 82)

Current Profit Sharing Rider Factors:

On a quarterly basis, the applicable energy charges for electric service shall be increased or decreased to the nearest $0.000001 per kWh to reflect the sharing of net proceeds as outlined in the formula below.

Rider PSM Factor = (((OSS + NF + CAP+REC) x 0.90) + R) / S

where:

OSS= Net proceeds from off-system power sales.

Includes the non-native portion of fuel-related costs charged to the Company by PJM Interconnection LLC including but not limited to those costs identified in the following Billing Line Items, as may be amended from time to time by PJM Interconnection LLC: Billing Line Items 1210, 2210, 1215, 1218, 2217, 2218, 1230, 1250, 1260, 2260, 1370, 2370, 1375, 2375, 1400, 1410, 1420, 1430, 1478, 1340, 2340, 1460, 1350, 2350, 1360, 2360, 1470, 1377, 2377, 1480, 1378, 2378, 1490, 1500, 2420, 2220, 1200, 1205, 1220, 1225, 2500, 2510, 1930, 2211, 2215, 2415 and 2930.

NF = Net proceeds from non-fuel related Regional Transmission Organization charges and credits not recovered via other mechanisms.

Includes non-fuel related costs charged to the Company by PJM Interconnection LLC including but not limited to those costs identified in the following Billing Line Items, as may amended from time to time by PJM Interconnection LLC: Billing Line Items 1240, 2240, 1241, 2241, 1242, 1243, 1245, 2245, 1330, 2330, 1362, 2362, 1472, 1365, 2365, 1475, 1371, 2371, 1376, 2376, 1380 and 2380.

CAP= Net proceeds from: PJM charges and credits as provided for in the Commission's Order in Case No. 2014-00201, dated December 4, 2014; capacity sales; capacity purchases; capacity performance credits; and capacity performance assessments.

REC= Net proceeds from the sales of renewable energy credits.

R = Reconciliation of prior period Rider PSM actual revenue to amount calculated for the period.

S = Current period sales in kWh as used in the Rider FAC calculation.

The Company proposes to revise the list of PJM Interconnection LLC Billing Line Items and the formula to calculate the Rider PSM Factor.

Proposed Profit Sharing Rider Factors:

On a quarterly basis, the applicable energy charges for electric service shall be increased or decreased to the nearest $0.000001 per kWh to reflect the sharing of net proceeds as outlined in the formula below.

Rider PSM Factor = (((OSS + NF + CAP + CPI + GS + REC) x 0.90) + R) / S

where:

OSS= Net proceeds from off-system power sales.

Includes the non-native portion of fuel-related costs charged to the Company by PJM Interconnection LLC including but not limited to those costs identified in the following Billing Line Items, as may be amended from time to time by PJM Interconnection LLC: Billing Line Items 1210, 1215, 1216, 1218, 2217, 2218, 1230, 1250, 1260, 2260, 1370, 2370, 1375, 2375, 1400, 1410, 1420, 1430, 1478, 1340, 2340, 1460, 1350, 2350, 1360, 2360, 2366, 1470, 1377, 2377, 1480, 1378, 2378, 1490, 1500, 2420, 2220, 1200, 1205, 1220, 1225, 2500, 2510, 1930, 2211, 2215, 2415, 2930,1980, 2980 and 1999.

NF= Net proceeds from non-fuel related Regional Transmission Organization charges and credits not recovered via other mechanisms.

Includes non-fuel related costs charged to the Company by PJM Interconnection LLC including but not limited to those costs identified in the following Billing Line Items, as may amended from time to time by PJM Interconnection LLC: Billing Line Items 2240, 2241, 1242, 1243, 1245, 2245, 1246, 2246, 1330, 2330, 1361, 2361, 2367, 1471, 1362, 2362, 2368, 1472, 1475, 1371, 2371, 1376, 2376, 1380, 2380, 1390, 2390, 1980, 2980, and 1999.

CAP= Net proceeds from: PJM charges and credits as provided for in the Commission's Order in Case No. 2017-00321, dated April 13, 2018, capacity sales; capacity purchases; capacity performance credits; and capacity performance assessments.

Includes FRR capacity costs charged to the Company by PJM Interconnection LLC including but not limited to those costs identified in the following Billing Line Items, as may amended from time to time by PJM Interconnection LLC: Billing Line Items 1600, 2600, 1666, 2666, 1667, 2667, 1669, 2669, 1670, 2670, 1681, 2681, 1980, 2980, 1985, and 1999,

CPI= Net proceeds of capacity performance insurance.

GS= Net proceeds from the sale of surplus gas on the pipelines.

REC= Net proceeds from the sales of renewable energy credits.

R= Reconciliation of prior period Rider PSM actual revenue to amount calculated for the period.

S= Current period sales in kWh as used in the Rider FAC calculation.

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

	Current Rate	Proposed Rate
Reconnections that can be accomplished remotely	$5.60	$6.50
Reconnections that cannot be accomplished remotely	$8.25	$5.80
Reconnections where service was disconnected at pole	$18.00	$16.50
After hours reconnection charge	$40.00	N/A

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

	Current Rate	Proposed Rate
Two-user pole annual rental per foot	$8.59	$7.50
Three-user pole annual rental per foot	$7.26	$7.50
Conduit fee per linear foot	$0.27	$0.67

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	2.0034¢	3.3518¢
Primary Service	1.6479¢	2.8504¢
Transmission Service	0.6915¢	1.0568¢
Program Charge per billing period	$183.00	$183.00

The foregoing rates reflect a proposed increase in electric revenues of approximately $70,008,476 or 14.69% 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:	$33,271,203	16.2%
Rate DS – Service at Distribution Voltage	$19,167,181	14.1%
Rate DT – Time-of-Day Rate for Service at Distribution Voltage	$15,314,005	14.1%
Rate EH – Optional Rate for Electric Space Heating	$272,039	13.9%
Rate SP – Seasonal Sports Service	$7,566	14.2%
Rate GS-FL – General Service Rate for Small Fixed Loads	$119,011	14.2%
Rate DP – Service at Primary Distribution Voltage	$53,265	5.9%
Rate TT – Time-of-Day Rate for Service at Transmission Voltage	$1,240,683	8.0%
Rate SL – Street Lighting Service	$198,711	13.8%
Rate TL – Traffic Lighting Service	$13,791	13.1%
Rate UOLS – Unmetered Outdoor Lighting Electric Service	$81,072	13.1%
Rate NSU – Street Lighting Service for Non-Standard Units	$13,460	13.8%
Rate SC – Street Lighting Service – Customer Owned	$861	13.1%
Rate SE – Street Lighting Service – Overhead Equivalent	$35,981	13.8%
Rate LED – Street Lighting Service – LED Outdoor Lighting	$2,807	14.0%
Rate RTP – Experimental Real Time Pricing Program	$60,394	9.8%
Interdepartmental	$4,994	14.9%
Special Contracts	$135,535	13.7%
Reconnection Charges	$8,323	15.1%
Rate DPA – Pole and Line Attachments	$7,594	1.1%

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:	904	$21.47	16.1%
Rate DS – Service at Distribution Voltage	7,079	$168.98	14.2%
Rate DT – Time-of-Day Rate for Service at Distribution Voltage	611,498	$6,030.34	13.9%
Rate EH – Optional Rate for Electric Space Heating	19,031	$133.46	13.7%
Rate SP – Seasonal Sports Service	1,971	$35.66	15.0%
Rate GS-FL – General Service Rate for Small Fixed Loads	537	$10.92	15.3%
Rate DP – Service at Primary Distribution Voltage	64,391	$1,597.25	6.0%
Rate TT – Time-of-Day Rate for Service at Transmission Voltage	1,188,866	$8,442.80	8.1%
Rate SL – Street Lighting Service *	66	$1.92	13.7%
Rate TL – Traffic Lighting Service	921	$8.84	13.1%
Rate UOLS – Unmetered Outdoor Lighting Electric Service	279	$2.64	13.0%
Rate NSU – Street Lighting Service for Non-Standard Units*	49	$1.67	13.9%
Rate SC – Street Lighting Service – Customer Owned *	44	$0.41	12.8%
Rate SE – Street Lighting Service – Overhead Equivalent *	59	$1.75	13.8%
Rate LED – Street Lighting Service – Led Outdoor Lighting *	18	$1.23	14.0%
Rate RTP – Experimental Real Time Pricing Program	275,766	$1,233.48	15.9%
Interdepartmental	N/A	$416.17	14.9%
Reconnection Charge (per remote reconnection)	N/A	$0.90	16.1%
Reconnection Charge (at meter per reconnection)	N/A	($2.45)	-29.7%
Reconnection Charge (at pole per reconnection)	N/A	($1.50)	-8.3%
Rate DPA - Pole and Line Attachments (2-user attachment per foot)	N/A	($1.09)	-12.7%
Rate DPA – Pole and Line Attachments (3-user attachment per foot)	N/A	$0.24	3.3%
Rate DPA – Conduit Fee	N/A	$0.40	148.1%

*For these 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

DUKE ENERGY KENTUCKY, INC

Calculation of Federal and State Composite Income Tax Rate

1	Income before Income Tax	100.00%
2		
3	Kentucky State Income Tax Rate	5.00%
4		
5	Apportionment Factor	99.37%
6		
7	Income Taxes - State of Kentucky (Line 3 x Line 5)	4.97%
8		
9	Income Before Federal Income Tax (Line 1 - Line 7)	95.03%
10		
11	Federal Income Tax (21% x Line 9)	19.96%
12		
13	Federal and State Composit Income Tax Rate (Line 7 + Line 11)	**24.93%**

DUKE ENERGY KENTUCKY, INC

Calculation of DEK's Levelized Fixed Charge Rate - Proposed in Application

For Plant With A 5 Year Life

Rate	Symbol	LFCR Components Description
7.97%	r	Rate of Return (Cost of Capital)
20.00%	D	Depreciation Rate
0.457%	A	Property Tax Rate
0.040%	P	Property Insurance Rate
24.930%	T	Federal and State Composite Income Tax Rate
1.95%	i	Synchronized Interest Deduction
17.06%	d	Sinking Fund Depreciation Rate
0.000%	g	Commercial Activity Tax
5	N	Service Life

$$LFCR = \frac{1}{1-g}\left[(r + A + P + d) + \left(\frac{T}{1-T}\right)(r + d - D)\left(\frac{r-i}{r}\right)\right]$$

LFCR = **26.79%**

0.0503	r+d-D
1	1/(1-G)
0.332090049	T/(1-T)
0.755271084	(r-i)/r
0.2552468	r+A+P+d
0.0000	check total

Proposed Capital Structure

Rate of Return

	Cost Rate	Capital Ratio	Weighted Cost
Long Term Debt	4.929%	42.483%	2.094%
Short Term Debt	3.197%	4.789%	0.153%
Preferred Stock	0.000%	0.000%	0.000%
Common Equity	10.850%	52.728%	5.721%
ITC	0.000%	0.000%	
Deferred Taxes	0.000%	0.000%	
		100.000%	7.968%

0.022325

Duke Energy Kentucky, Inc.
Case No. 2024-00354
Attachment BLS-2
LFCR Values
Page 1 of 1

Service Life	Annual LFCR	Monthly LFCR	
5	26.79%	2.2325%	
10	16.60%	1.3833%	
15	13.41%	1.1175%	
20	11.95%	0.9958%	
30	10.74%	0.8950%	
38.1	10.37%	0.8642%	Average Depreciable Life of Distribution Equipment

CONFIDENTIAL PROPRIETARY TRADE SECRET

DUKE ENERGY KENTUCKY, INC

DEK Levelized Fixed Charge Rates by Service Life

		Annual
1	**Service Life**	**LFCR**
2	10	16.60%
3	15	13.41%
4	20	11.95%
5	30	10.74%

2024 Rates

Stores, Freight Handling	**11.00%**
Design and Project Mgmt Adder	**16.40%**
Mgmt and Supervison Adder	**24.40%**
Crew Hourly Rate w Burden	**$82.14**

CONFIDENTIAL PROPRIETARY TRADE SECRET

Useful Life Assumptions for LFCR Selection

Equipment Type	Life Assumption
Fixtures	15
Poles	30
Brackets	30
Shrouds	30
Foundations	30
Wiring	30
Shields	30

CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Kentucky
Monthly Rate for New LED Equipment
Confidential Attachment BLS-3

				Lumens	Watts	kWh	Fixture Cost	PE Cost	Ancillary Cost	Cost	Minor Materials Adder	Stores, Freight, Handling	**Total Cost w/ Material**	Crew Hourly Rate w/ Burden		Labor		Set Up Overheads	Fleet Indirect Adder	Design & Project Mgmt Adder	Mgmt & Supervisn Adder	**Total Labor**	**Total Labor, Material & Overhead**	Monthly Rate
											5.76%	11.00%		$82.14					0.00%	16.40%	24.40%			13.41%
New Fixtures																								
	Operand	CU Name (1)	Fixtures (New to Tariff)																					
New	LG30	LFIX-ACG-LED-30-BLK-III-3000K-M	Acorn Granville	4100	30	10.4	[redacted]							$82.14	0.5	$41.07	0.5	$41.07	$0.00	$13.47	$20.04	**$115.65**	[redacted]	$11.75
New	L10STBB	LFIX-STYB-30W-BLK-V-3000K-LBOLL-M	Style B Bollard	2390	30	10.4	[redacted]							$82.14	2.5	$205.35	0.5	$41.07	$0.00	$40.41	$60.13	**$346.96**	[redacted]	$15.31
New	L10.4STCB	LFIX-STYC-30W-BLK-V-3000K-LBOLL-M	Style C Bollard	2146	30	10.4	[redacted]							$82.14	2.5	$205.35	0.5	$41.07	$0.00	$40.41	$60.13	**$346.96**	[redacted]	$15.31
New	L104STBL5	LFIX-STYD-30W-BLK-V-3000K-LBOLL-M	Style D Bollard	2390	30	10.4	[redacted]							$82.14	2.5	$205.35	0.5	$41.07	$0.00	$40.41	$60.13	**$346.96**	[redacted]	$15.31
New	L10.4STEB	LFIX-STYE-30W-BLK-V-3000K-LBOLL-M	Style E Bollard	1200	30	10.4	[redacted]							$82.14	2.5	$205.35	0.5	$41.07	$0.00	$40.41	$60.13	**$346.96**	[redacted]	$15.31
New	L40COLB	LFIX-COL-40W-BLK-V-3000K-LBOLL-M	Colonial Bollard	1107	40	13.9	[redacted]							$82.14	3	$246.42	0.5	$41.07	$0.00	$47.15	$70.15	**$404.79**	[redacted]	$19.48
New	L40WASB	LFIX-WASH-40W-BLK-V-3000K-LBOLL-M	Washington Bollard	1107	40	13.9	[redacted]							$82.14	3	$246.42	0.5	$41.07	$0.00	$47.15	$70.15	**$404.79**	[redacted]	$19.48
New	LHOLRR	LPOLE-RECPT-HDAY-RISER-GRAY-M	Holiday Riser Receptacle	NA	26	9.0	[redacted]							$82.14	0.5	$41.07	0.5	$41.07	$0.00	$13.47	$20.04	**$115.65**	[redacted]	$4.21
New	LHOLBR	LPOLE-RECPT-HDAY-BRKT-TOP-BLK-M	Holiday Bracket Top Receptacle	NA	26	9.0	[redacted]							$82.14	0.5	$41.07	0.5	$41.07	$0.00	$13.47	$20.04	**$115.65**	[redacted]	$4.96
New	LHOLFR	LPOLE-RECPT-HDAY-FESTOON-BLK-M	Holiday Festoon Receptacle	NA	26	9.0	[redacted]							$82.14	0.5	$41.07	0.5	$41.07	$0.00	$13.47	$20.04	**$115.65**	[redacted]	$5.85
New	LHOLPTR	LPOLE-RECPT-HDAY-PT-BLK-M	Holiday Post Top Receptacle	NA	26	9.0	[redacted]							$82.14	0.5	$41.07	0.5	$41.07	$0.00	$13.47	$20.04	**$115.65**	[redacted]	$5.32
New	LHOLPTAR	LPOLE-RECPT-HDAY-PT-RING-BLK-M	Holiday Post Top with Adapter Receptacle	NA	26	9.0	[redacted]							$82.14	0.5	$41.07	0.5	$41.07	$0.00	$13.47	$20.04	**$115.65**	[redacted]	$5.91
New	LDUPTR	LPOLE-RECPT-DUAL-PT-BLK-M	Dual Post Top Receptacle	NA	26	9.0	[redacted]							$82.14	0.5	$41.07	0.5	$41.07	$0.00	$13.47	$20.04	**$115.65**	[redacted]	$6.94
New	LDUPTAR	LPOLE-RECPT-DUAL-PT-RING-BLK-M	Dual Post Top with Adapter Receptacle	NA	26	9.0	[redacted]							$82.14	0.5	$41.07	0.5	$41.07	$0.00	$13.47	$20.04	**$115.65**	[redacted]	$7.53
New	LDUBR	LPOLE-RECPT-DUAL-BRKT-TOP-BLK-M	Dual Bracket Top Receptacle	NA	26	9.0	[redacted]							$82.14	0.5	$41.07	0.5	$41.07	$0.00	$13.47	$20.04	**$115.65**	[redacted]	$6.94
New	LSE50	LFIX-SEN-LED-50-BLK-IV-3000K-M	Senoia	4525	50	17.3	[redacted]							$82.14	0.5	$41.07	0.5	$41.07	$0.00	$13.47	$20.04	**$115.65**	[redacted]	$15.68
New	LHA50	LFIX-HALO-LED-50-BLK-IV-3000K-M	Halo	4809	50	17.3	[redacted]							$82.14	0.5	$41.07	0.5	$41.07	$0.00	$13.47	$20.04	**$115.65**	[redacted]	$17.64
New	LRDW030	LFIX-RW-LED-30-BLK-III-3000K-M	Roadway (Standard)	3720	30	10.4	[redacted]							$82.14	0.7	$57.50	0.5	$41.07	$0.00	$16.17	$24.05	**$138.78**	[redacted]	$3.17
New	LRDW040	LFIX-RW-LED-40-BLK-III-3000K-M	Roadway (Standard)	4506	40	13.9	[redacted]							$82.14	0.7	$57.50	0.5	$41.07	$0.00	$16.17	$24.05	**$138.78**	[redacted]	$3.18
New	L30OB3KH	LFIX-OBTM-LED-30-GRAY-III-3000K-M	Open Bottom	4510	30	10.4	[redacted]							$82.14	0.7	$57.50	0.5	$41.07	$0.00	$16.17	$24.05	**$138.78**	[redacted]	$3.06

CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Kentucky
Monthly Rate for New LED Equipment
Confidential Attachment BLS-3

	Order	Operands	Shields (New to Tariff)	Style	Cost	Minor Materials Adder	Stores, Freight, Handling	Total Cost w/ Material	Crew Hourly Rate w/ Burden		Labor		Set Up Overheads	Fleet Indirect Adder	Design & Project Mgmt Adder	Mgmt & Supervisn Adder	Total Labor	Total Labor, Material & Overhead	Monthly Rate
						5.76%	11.00%		$82.14					0.00%	16.40%	24.40%			10.74%
NEW	1	TBD	Standard	Standard	[redacted]				$82.14	0.87	$71.46	0.5	$41.07	$0.00	$18.46	$27.46	$158.44	[redacted]	$1.83
NEW	2	TBD	Decorative	Decorative	[redacted]				$82.14	0.87	$71.46	0.5	$41.07	$0.00	$18.46	$27.46	$158.44	[redacted]	$1.71

CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Kentucky
Case No. 2024-00354
Calculation of Electric Non-Remote Reconnection Fees
Confidential Attachment BLS-4

Base Labor		$45.60	
Unproductive	25.0%	$11.40	Loads on Base - direct labor
Incentives	11.0%	$6.27	Loads on Base plus Unprod
Subtotal		$17.67	
Fringes	25.6%		
Payroll Tax	7.5%		
Subtotal	33.1%	$20.94	Loads on Base plus Unprod plus incentive
Loaded Labor		$84.21	
Fleet	30.0%	$25.26	Load on Loaded Labor
Indirects	24.4%	$20.55	Load on Loaded Labor
Engineering	16.4%	$13.81	Load on Loaded Labor
Total Cost Per Hour		$143.83	

	Approximate Hours	Cost		Propose
Electric Non-Remote Reconnection	0.23	$5.80		**$ 5.80**
Pole Reconnection	0.66	$16.56	Single person crew	**$ 16.50**
Non-Remote After Hours				eliminate
Pole Reconnection After Hours				eliminate

Duke Energy Kentucky
Case No. 2024-00354
Calculation of Electric Remote Reconnection Fees
Confidential Attachment BLS-4

	Vendor	Duke
Cost/min Breakdown		
Base rate/min	[redacted]	$ 1.14
Shrinkage (includes training)		
Overtime		
Supervision/Administration		
Management		$ 0.09
Other		$ 0.05
Total cost/min		$ 1.28
Percent of DNP calls handled by group	64%	36%
AHT in secs for a DNP call	385	454
	[redacted]	$ 9.65
Cost per call - Loaded		**$ 6.50**

Duke Energy Kentucky

Case No. 2024-00354

Revised CATV Pole Attachment Formula - Adminstrative Case No. 251

For Use of Electric Utility Poles

BASED UPON 2023 FERC FORM 1 DATA

	FCC Pole Attachment Rate Formula	Gross Pole Investment (A)	Pole Depreciation Reserve (B)	Appurtenance Factor (C)=(A-B+D)*15%	Accumulated Deferred Taxes (Poles) (D)	Net Pole Investment (E)=A-B+D	Number Of Poles (F)	Net Investmnt Per Bare Poles (G)=(E-C)/F	Usable Space in ft (H)	Number of Attachments 0	1	2	3	4	>=5	Total	Number of Attachments <=2	>=3	Total
1	30' Or Less	$1,135,938	$376,789	$94,485	($129,248)	$629,901	2,010	$266.38	7.0	1,275	558	600	129	26	6	2,594	2,433	161	2,594
2	35'	$5,298,940	$1,757,653	$440,756	($602,916)	$2,938,371	6,449	$387.29	11.5	2,480	1,752	2,422	511	99	23	7,287	6,654	633	7,287
3	40'	$16,983,441	$5,633,390	$1,412,650	($1,932,384)	$9,417,667	16,253	$492.53	16.0	3,223	3,945	7,204	2,179	585	237	17,373	14,372	3,001	17,373
4	45'	$20,737,607	$6,878,643	$1,724,914	($2,359,535)	$11,499,429	10,994	$889.08	20.5	3,235	2,435	4,661	1,886	799	582	13,598	10,331	3,267	13,598
5	50'	$7,421,795	$2,461,802	$617,331	($844,456)	$4,115,537	3,071	$1,139.11	25.0	922	545	988	561	331	316	3,663	2,455	1,208	3,663
6	55'	$3,012,263	$999,165	$250,554	($342,737)	$1,670,361	1,089	$1,303.77	29.5	308	190	325	241	109	129	1,302	823	479	1,302
7	60'	$1,518,378	$503,645	$126,296	($172,762)	$841,971	452	$1,583.35	34.0	182	64	172	67	40	41	566	418	148	566
8	65'	$526,168	$174,529	$43,766	($59,868)	$291,771	119	$2,084.08	38.5	56	25	40	21	11	17	170	121	49	170
9	70'	$367,501	$121,900	$30,568	($41,814)	$203,787	67	$2,585.36	43.0	28	18	28	11	5	5	95	74	21	95
10	75'	$103,320	$34,271	$8,594	($11,756)	$57,293	13	$3,746.08	47.5	8	2	10	1	1	1	23	20	3	23
11	80'	$65,947	$21,874	$5,486	($7,503)	$36,570	13	$2,391.12	52.0	10	1	5	1	1	-	18	16	2	18
12	85'	($1,099)	($364)	($92)	$125	($610)	2	($259.25)	56.5	2	1	1	-	-	1	5	4	1	5
13	90'	$18,163	$6,025	$1,511	($2,067)	$10,071	4	$2,140.09	61.0	4	-	-	-	-	-	4	4	-	4
14	95'	($7,083)	($2,349)	($589)	$806	($3,928)	1	($3,338.80)	65.5	1	-	-	-	-	-	1	1	-	1
15	Total	$57,181,279	$18,966,973	$4,756,229	($6,506,115)	$31,708,191	40,537	**$664.87**											

		Two or Less User	Three or More User	Single Rate
16	Net Investment per Bare Pole (Weighted Average)	$651.57	$788.79	
17	Maintenance of Overhead Lines	$6,561,383	$6,561,383	
18	Total Investment in Poles, Conductors, Services	$262,868,714	$262,868,714	
19	Depreciation Reserve	$69,617,758	$69,617,758	
20	Accumulated Deferred Taxes	($29,913,049)	($29,913,049)	
21	Total Investment in Poles - Net	$163,337,907	$163,337,907	
22	Pole Maintenance Ratio	4.02%	4.02%	
23	Depreciation	3.77%	3.77%	
24	Administration	2.05%	2.05%	
25	Taxes (Normalized)	1.69%	1.69%	
26	Rate of Return	7.968%	7.968%	
27	Total Carrying Charge	19.49%	19.49%	
28	Space Occupied	1.00	1.00	
29	Usable Space	17.11	19.6	
30	Allocated Space	5.84%	5.10%	
31	Maximum Rate Per Attachment	**$7.42**	**$7.84**	
32	Number of Attachments	37,726	8,973	46,699
33	Revenue	$280,048	$70,392	$350,440
34	Weighted Average Rate			**$7.50**

Input Data

A.	Poles, Towers, & Fixtures (Acctg.364)	$79,009,021	FERC Form 1, Page 207, Line 64, Column g
B.	Accum. Depr. - Distribution Plant	$160,353,451	FERC Form 1, Page 219, Line 26, Column c.
	1. Accum Depr. for FERC Acctg 364	$26,207,213	Provided by Plant Accounting
	2. Accum Depr. for FERC Acctg 365	$32,839,432	Provided by Plant Accounting
	3. Accum Depr. for FERC Acctg 369	$10,571,112	Provided by Plant Accounting
C.	Gross Investment - Distribution Plant	$690,968,816	FERC Form 1, Page 207, Line 75, Column g
D.	Number of Distribution Poles	40,537	Provided by Plant Accounting
E.	Mtce of Overhead Lines (Acctg. 593)	$6,561,383	FERC Form 1, Page 322, Line 149, Column b.
F.	Overhead Conductors & Devices (Acctg. 365)	$161,459,055	FERC Form 1, Page 207, Line 65, Column g.
G.	Services (Acctg. 369)	$22,400,638	FERC Form 1, Page 207, Line 69, Column g.
H.	Depreciation Rate - Distribution Property	2.09%	Provided by Plant Accounting
I.	Admin. & Gen. Exps. (Acctgs. 920-935)	$24,047,481	FERC Form 1, Page 323, Line 197, Column b.
J.	Utility Plant in Service	$2,318,455,311	FERC Form 1, Page 200, Line 8, Column c.
K.	Accum. Depr. - Utility Plant in Service	$880,996,299	FERC Form 1, Page 200, Line 22, Column c.
	1. ADIT - Accelerated Amort. Property (Acctg. 281)	$0	FERC Form 1, Page 273, Line 8, Column k.
	2. ADIT - Other Property (Acctg. 282)	$241,961,189	FERC Form 1, Page 275, Line 2, Column k.
	3. ADIT - Other (Acctg. 283)	$25,097,565	FERC Form 1, Page 277, Line 9, Column k.
L.	Taxes Other Than Income Taxes (Acctg. 408.1)	$11,785,321	FERC Form 1, Page 115, Line 14, Column g.
M.	Income Taxes - Federal (Acctg. 409.1)	$9,069,527	FERC Form 1, Page 115, Line 15, Column g.
N.	Income Taxes - Other (Acctg. 409.1)	$535,181	FERC Form 1, Page 115, Line 16, Column g.
O.	Prov. for Deferred Inc. Taxes (Acctg 410.1)	$44,373,898	FERC Form 1, Page 115, Line 17, Column g.
P.	(Less) Prov. for Def. Inc. Taxes - Cr. (Acctg 411.1)	($45,923,485)	FERC Form 1, Page 115, Line 18, Column g.
Q.	Investment Tax Credit Adj. - Net (Acctg 411.4)	$0	FERC Form 1, Page 115, Line 19, Column g.
R.	Accumulated Deferred Inc. Taxes (Acct 190, 281, 282	($262,856,329)	Deferred Tax Calculation Worksheet
	1. ADIT for Poles (Acct 364)	($8,989,686)	Deferred Tax Calculation Worksheet
	2. ADIT for Overhead Conductor (Acct 365)	($18,373,657)	Deferred Tax Calculation Worksheet
	3. ADIT for Services (Acct 369)	($2,549,706)	Deferred Tax Calculation Worksheet
S.	Rate of Return	7.968%	Proposed in KYPSC Case No. 2024-00354

				Cost with Unitizations			Quantity with Unitizations		
	Cost	# of Poles		12/31/2023	Unitizations	Total	12/31/2023	Unitizations	Total
30' or Less	1,135,937.78	2,010	1.438%	1,135,937.78	6,294.49	1,142,232.27	2,010	4	2,014
35'	5,298,939.55	6,449	6.707%	5,298,939.55	56,266.02	5,355,205.57	6,449	18	6,467
40'	16,983,440.93	16,253	21.496%	16,983,440.93	117,781.89	17,101,222.82	16,253	33	16,286
45'	20,737,606.59	10,994	26.247%	20,737,606.59	663,487.12	21,401,093.71	10,994	195	11,189
50'	7,421,794.81	3,071	9.394%	7,421,794.81	428,462.09	7,850,256.90	3,071	74	3,145
55'	3,012,262.88	1,089	3.813%	3,012,262.88	150,428.93	3,162,691.81	1,089	22	1,111
60'	1,518,378.18	452	1.922%	1,518,378.18	161,999.04	1,680,377.22	452	21	473
65'	526,168.06	119	0.666%	526,168.06	87,316.33	613,484.39	119	10	129
70'	367,500.53	67	0.465%	367,500.53	87,717.27	455,217.80	67	6	73
75'	103,319.66	13	0.131%	103,319.66	-	103,319.66	13	-	13
80'	65,946.68	13	0.083%	65,946.68	-	65,946.68	13	-	13
85'	(1,098.78)	2	-0.001%	(1,098.78)	-	(1,098.78)	2	-	2
90'	18,162.72	4	0.023%	18,162.72	-	18,162.72	4	-	4
95'	(7,083.08)	1	-0.009%	(7,083.08)	-	(7,083.08)	1	-	1
Sum	$57,181,277	40,537	72.373%						
Poles, Towers & Fixtures	$79,009,021								

Duke Energy Kentucky
Allocation of Accumulated Deferred Tax Balances (Acct. 190)
To Plant Accounts 364, 365 and 369
Twelve Months Ended December 31, 2023

Poles

			Allocated ADIT Amounts ($)	FERC Form No. 1 Source
Accumulated Deferred Taxes (Acct. 190)			$55,425,410	Pg 234, line 8, column c
ADIT - Accelerated Amort. Property (Acctg. 281)			$0	Pg 272, Line 8, Column k.
ADIT - Other Property (Acctg. 282)			($241,961,189)	Pg 274, Line 2, Column k.
ADIT - Other (Acctg. 283)			(25,097,565)	Pg 276, Line 9, Column k.
ADIT - Tax Reform Act (Acctg. 254)			(51,222,985)	Attachment H-22A of Rate Case (Protected + Unprotected)
Accumulated Deferred Taxes for Electric			($262,856,329)	
		% of Total		
Electric Plant in Service	($)		($)	
Total Plant	$2,311,025,198	100.00%		Pg 207, line 104, column g
Poles (Acct. 364)	$79,009,021	3.42%	($8,989,686)	FERC Form 1, Page 207, Line 64, Column g
Overhead Conductor (Acct. 365)	$161,459,055	6.99%	(18,373,657)	FERC Form 1, Page 207, Line 65, Column g.
Services (Acct. 369)	$22,400,638	0.97%	(2,549,706)	FERC Form 1, Page 207, Line 69, Column g.
Total Accts 364, 365 and 369			($29,913,049)	

Source: Duke Energy Kentucky 2023 FERC Form No. 1

Pole Length	Buried Portion	Ground Clearance	Usable Space
30	5.0	18	7.0
35	5.5	18	11.5
40	6.0	18	16.0
45	6.5	18	20.5
50	7.0	18	25.0
55	7.5	18	29.5
60	8.0	18	34.0
65	8.5	18	38.5
70	9.0	18	43.0
75	9.5	18	47.5
80	10.0	18	52.0
85	10.5	18	56.5
90	11.0	18	61.0
95	11.5	18	65.5

Duke Energy Kentucky

Case No. 2024-00354 - Attachment BLS-6

Formula For Use of Electric Utility Conduit (FCC 01-170 Appendix F-2)

BASED UPON 2023 FERC FORM 1 DATA

	FCC Conduit Rate Formula	Amount	Reference/Source
1	Gross Conduit Investment	$48,115,495	A Below
2	Conduit Depreciation Reserve	$8,913,085	B1 below
3			
4	Accumulated Deferred Taxes	($5,467,412)	R1 Below
5	Net Conduit Investment	$33,734,998	1 - 2 + R1
6	Number of Duct Feet of Conduit	3,447,008	D Below
7	Net Investment Per Duct Feet	$9.79	5 / 6
8	Maintenance		
	A. Maintenance of Underground Lines	$280,733	E Below
	B. Total Investment in Conduit	$165,871,541	A + F + G
	C. Depreciation Reserve	$40,198,454	B1 + B2 + B3
	D. Accumulated Deferred Taxes	-$18,873,084	R1 + R2 + R3
	E. Total Investment in Conduit - Net	$106,800,003	8B - 8C + 8D
	F. Conduit Maintenance Ratio	0.26%	8A / 8E
9	Depreciation	2.45%	(1 / (1 - 2 - R1)) * H
10	Administration	1.41%	I / (J - K - R)
11	Taxes (Normalized)	1.69%	(L + M + N + O + P + Q) / (J - K + R)
12	Rate of Return	7.97%	Proposed
13	Total Carrying Charge	13.78%	8F + 9 + 10 + 11 + 12
14	Allocated Space	50%	Y / Z
15	Maximum Rate per Foot of Conduit	**$0.67**	7 * 13 * 14

Input Data

A.	Underground Conduit (Acctg.366)	$48,115,495	FERC Form 1, Page 207, Line 66, Column g
B.	Accum. Depr. - Distiburion Plant	$160,353,451	FERC Form 1, Page 219, Line 26, Column c
	1. Accum Depr. for FERC Acctg 366	$8,913,085	Provided by Asset Accounting
	2. Accum Depr. for FERC Acctg 367	$20,714,257	Provided by Asset Accounting
	3. Accum Depr. for FERC Acctg 369	$10,571,112	Provided by Asset Accounting
C.	Gross Investment - Distribution Plant	$690,968,816	FERC Form 1, Page 207, Line 75, Column g
D.	Number of Duct Feet of Conduit	3,447,008	Provided by Asset Accounting
E.	Maintenance of Underground Lines (Acctg. 594)	$280,733	FERC Form 1, Page 322, Line 150, Column b
F.	Underground Conductors & Devices (Acctg. 367)	$95,355,408	FERC Form 1, Page 207, Line 67, Column g
G.	Underground Services (Acctg. 369)	$22,400,638	FERC Form 1, Page 207, Line 69, Column g
H.	Depreciation Rate - Distribution Property	2.27%	Provided by Asset Accounting
I.	Admin. & Gen. Exps. (Acctgs. 920-935)	$24,047,481	FERC Form 1, Page 323, Line 197, Column b.
J.	Utility Plant in Service	$2,318,455,311	FERC Form 1, Page 200, Line 8, Column c.
K.	Accum. Depr. - Utility Plant in Service	$880,996,299	FERC Form 1, Page 200, Line 22, Column c.
L.	Taxes Other Than Income Taxes (Acctg. 408.1)	$11,785,321	FERC Form 1, Page 115, Line 14, Column g.
M.	Income Taxes - Federal (Acctg. 409.1)	$9,069,527	FERC Form 1, Page 115, Line 15, Column g.
N.	Income Taxes - Other (Acctg. 409.1)	$535,181	FERC Form 1, Page 115, Line 16, Column g.
O.	Prov. for Deferred Inc. Taxes (Acctg 410.1)	$44,373,898	FERC Form 1, Page 115, Line 17, Column g.
P.	(Less) Prov. for Def. Inc. Taxes - Cr. (Acctg 411.1)	($45,923,485)	FERC Form 1, Page 115, Line 18, Column g.
Q.	Investment Tax Credit Adj. - Net (Acctg 411.4)	$0	FERC Form 1, Page 115, Line 19, Column g.
R.	Accumulated Deferred Inc. Taxes (Acct 190, 281, 282, 283)	($262,856,329)	Deferred Tax Calculation Worksheet
	1. Underground Conduit (Acctg.366)	($5,467,412)	Deferred Tax Calculation Worksheet
	2. Underground Conductors & Devices (Acctg. 367)	($10,855,966)	Deferred Tax Calculation Worksheet
	3. Underground Services (Acctg. 369)	($2,549,706)	Deferred Tax Calculation Worksheet
S.			
T.			
U.			
V.			
X.	Rate of Return	7.968%	Proposed in KYPSC Case No. 2024-00354 - Att
Y.	Space Occupied (Ducts)	1.00	
Z.	Number of Inner Ducts per Conduit	2	

Case No. 2024-00354 - Attachment BLS-6

Duke Energy Kentucky
Allocation of Accumulated Deferred Tax Balances (Acct. 190)
To Plant Accounts 366, 367 and 369
Twelve Months Ended December 31, 2023

Conduit			Allocated ADIT Amounts	FERC Form No. 1 Source
			($)	
Accumulated Deferred Taxes (Acct. 190)			$55,425,410	Pg 234, line 8, column c
Excess ADIT (Acct. 254)			(51,222,985)	Rates
ADIT - Accelerated Amort. Property (Acctg. 281)			$0	Pg 273, Line 8, Column k.
ADIT - Other Property (Acctg. 282)			($241,961,189)	Pg 275, Line 2, Column k.
ADIT - Other (Acctg. 283)			(25,097,565)	Pg 277, Line 9, Column k.
Accumulated Deferred Taxes for Electric			($262,856,329)	
		% of Total		
Electric Plant in Service	($)		($)	
Total Plant	$2,311,025,198	100.00%		Pg 207, Column G, Line 104
Underground Conduit (Acctg.366)	48,115,495	2.08%	($5,467,412)	Conduit Formula Tab
Underground Conductors & Devices (Acctg. 367)	95,355,408	4.13%	(10,855,966)	Conduit Formula Tab
Underground Services (Acctg. 369)	$22,400,638	0.97%	(2,549,706)	Conduit Formula Tab
Total Accts 366, 367 and 369			($18,873,084)	

Source: Duke Energy Kentucky 2023 FERC Form No. 1