COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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

CASE NO. 2021-00190

FILING REQUIREMENTS

VOLUME 14

Duke Energy Kentucky, Inc.
Case No. 2021-00190
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.	Chris R. Bauer Bryan T. Manges
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	Jeff L. Kern
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.	Jeff L. Kern
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.	Abby L. Motsinger
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.	Jay P. Brown David G. Raiford Abby L. Motsinger
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.	Jay P. Brown
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.	Abby L. Motsinger

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.	Abby L. Motsinger
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.	Jay P. Brown
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.	Abby L. Motsinger Brian R. Weisker
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.	Abby L. Motsinger
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.	Abby L. Motsinger
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.	Abby L. Motsinger Brian R. Weisker
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.	Abby L. Motsinger Brian R. Weisker

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.	Abby L. Motsinger Brian R. Weisker Benjamin W. Passty
1	29	807 KAR 5:001 Section 16(7)(i)	Most recent FERC or FCC audit reports.	Bryan T. Manges
1	30	807 KAR 5:001 Section 16(7)(j)	Prospectuses of most recent stock or bond offerings.	Chris R. Bauer
1	31	807 KAR 5:001 Section 16(7)(k)	Most recent FERC Form 1 (electric), FERC Form 2 (gas), or PSC Form T (telephone).	Bryan T. Manges
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.	Chris R. Bauer
3	33	807 KAR 5:001 Section 16(7)(m)	Current chart of accounts if more detailed than Uniform System of Accounts charts.	Bryan T. Manges
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.	Bryan T. Manges
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.	Bryan T. Manges Abby L. Motsinger
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.	Bryan T. Manges
10	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.	Bryan T. Manges
10	38	807 KAR 5:001 Section 16(7)(r)	Quarterly reports to the stockholders for the most recent 5 quarters.	Chris R. Bauer

10	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
10	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	Jay P. Brown
10	41	807 KAR 5:001 Section 16(7)(u)	If utility had any amounts charged or allocated to it by affiliate or general or home office or paid any monies to affiliate or general or home office during the base period or during previous 3 calendar years, file: 1. Detailed description of method of calculation and amounts allocated or charged to utility by affiliate or general or home office for each allocation or payment; 2. method and amounts allocated during base period and method and estimated amounts to be allocated during forecasted test period; 3. Explain how allocator for both base and forecasted test period was determined; and 4. All facts relied upon, including other regulatory approval, to demonstrate that each amount charged, allocated or paid during base period is reasonable.	Jeffrey R. Setser
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.	Not Applicable
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.	Jay P. Brown

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.	Jay P. Brown David G. Raiford Abby L. Motsinger John R. Panizza James E. Ziolkowski Bryan T. Manges
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.	Jay P. Brown
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.	Jay P. Brown David G. Raiford Abby L. Motsinger 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.	Jay P. Brown
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.	Jay P. Brown Jake J. Stewart
10	51	807 KAR 5:001 Section 16(8)(h)	Computation of gross revenue conversion factor for forecasted period.	Jay P. Brown
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.	Bryan T. Manges Abby L. Motsinger
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.	Chris R. Bauer
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.	David G. Raiford Abby L. Motsinger Bryan T. Manges
10	55	807 KAR 5:001 Section 16(8)(l)	Narrative description and explanation of all proposed tariff changes.	Jeff L. Kern
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.	Jeff L. Kern
10	57	807 KAR 5:001 Section 16(8)(n)	Typical bill comparison under present and proposed rates for all customer classes.	Jeff L. Kern
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)	A request for a waiver 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. In determining if good cause has been shown, the commission shall consider: 1. if other information that the utility would provide if the waiver is granted is sufficient to allow the commission to effectively and efficiently review the rate application; 2. if the information that is the subject of the waiver request is normally maintained by the utility or reasonably available to it from the information that it maintains; and 3. the expense to the utility in providing the information that is the subject of the waiver request.	Not Applicable
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.	Jeff L. Kern
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.	Not Applicable

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)	Schedules L-N	Jeff L. Kern
13	-	-	Workpapers	Various
14	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 1 of 3)	Various
15	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 2 of 3)	Various
16	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 3 of 3)	Various
17-18	-	KRS 278.2205(6)	Cost Allocation Manual	Jeffrey R. Setser

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 Natural Gas Rates; 2) Approval of New Tariffs; and 3) All Other Required Approvals, Waivers, and Relief.	)))))	Case No. 2021-00190

DIRECT TESTIMONY OF

AMY B. SPILLER

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

June 1, 2021

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Amy B. Spiller, 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 State President of Duke Energy Kentucky, Inc., (Duke Energy Kentucky or the Company) and its parent, Duke Energy Ohio, Inc. (Duke Energy Ohio). 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 economics and management from Albion College in Michigan and a law degree from Wake Forest University in Winston-Salem, N.C. Following law school, I spent two years working for Business Laws, Inc., a legal publishing company in northeast Ohio. Then, from 1993 to 2003, I rose from associate to partner at Wilson & Markesbery Co., L.P.A., a small insurance defense law firm in Cincinnati, Ohio.

I joined Cinergy Corp., (Cinergy) in 2003 as an associate general counsel, focusing on litigation matters. In 2008, following the 2006 merger between Cinergy and Duke Energy, I was promoted to deputy general counsel, assuming responsibility relative to Duke Energy's strategic planning in Ohio and Kentucky. I was also responsible for advancing Duke Energy's rate and regulatory initiatives before the Public Utilities Commission of Ohio and the Kentucky Public Service Commission (Commission). In January of 2018, I was named Vice President of Government and Community Affairs for Duke Energy Ohio, where I was responsible for managing state government and regulatory policies, strategies, and relationships affecting Duke Energy Ohio's interests and those of our Ohio customers. On June 1, 2018, I was named to my current position of State President, Duke Energy Ohio and Duke Energy Kentucky.

Q. PLEASE DESCRIBE YOUR DUTIES AS STATE PRESIDENT, DUKE ENERGY KENTUCKY.

A. As State President, Duke Energy Kentucky, I am responsible for ensuring that our customers continue to have access to safe, reliable, reasonable, adequate and affordable electric and natural gas service and that these services are provided in accordance with applicable federal and state laws and regulations. I am also involved in external efforts relating to governmental and regulatory affairs, interacting with state and community leaders and regulators on matters relevant to Duke Energy Kentucky's business and presence in the Commonwealth. Finally, I am responsible for the Company's community relations and economic development efforts, as well as Duke Energy's charitable contributions in the Northern Kentucky/Greater Cincinnati region.

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

A. Yes. Most recently, I provided testimony in Case No. 2019-00271 supporting the Company's application for an increase in electric base rates.

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

A. My testimony provides an overview of Duke Energy Kentucky's natural gas business operations and community involvement in our Northern Kentucky service territory. I discuss Duke Energy Kentucky's levels of customer satisfaction and how the constructive regulatory treatment sought in this proceeding will enable the Company to meet our customers' expectations. I then discuss the major developments since our last natural gas base rate case, Case No. 2018-00261 (2018 Rate Case), including, but not limited to, the construction and planned completion of the Company's UL-60 natural gas pipeline.

I next provide an overview of Duke Energy Kentucky's need for an increase in natural gas rates and the reasonableness of this request. I provide support for the Company's proposed adjustment mechanism to respond to governmental mandates (Rider GMA). I also introduce the other witnesses who testify on the Company's behalf and, in doing so, provide an overview of their testimony.

I sponsor several Filing Requirements (FR), including those required under 807 KAR 5:001: FR 14(1) through FR 14(4), FR 16(1)(b)(1), FR 16(1)(b)(2), FR 16(1)(b)(5), FR 16(2), and FR 16(3). I discuss the existing programs to achieve improvements in efficiency and productivity and the purpose of each program, as required by FR 16(7)(a). I provide the management statement of attestation, required by FR 16(7)(e), concerning the forecasted financial data.

Finally, I sponsor the affidavit in support of the notice requirements under FR 17(1) through (3).

II. OVERVIEW OF KENTUCKY OPERATIONS

A. COMPANY OVERVIEW

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S UTILITY OPERATIONS IN NORTHERN KENTUCKY.

A. Duke Energy Kentucky provides natural gas service to customers in Bracken, Boone, Campbell, Gallatin, Grant, Kenton, and Pendleton counties in Northern Kentucky.[1] The Company owns, operates, and maintains approximately 1,502 miles of gas mains on our natural gas distribution system.

Duke Energy Kentucky's natural gas customer classes include approximately 94,500 residential customers, 7,680 commercial customers, and 242 industrial customers. Additionally, the Company provides service to numerous public authorities, as well as firm and interruptible transportation customers. Although not heavily industrialized, our relatively densely populated territory consists of a diverse mix of commercial and industrial customers that includes automotive suppliers, food production, transportation, colleges and universities, manufacturing and retail, and health care providers.

The Company's local operations as it relates to natural gas utility service are as follows:

- Cincinnati, Ohio – the headquarters for Duke Energy Kentucky, the Queensgate meter testing facility, and Kellogg Avenue Resource Center

[1] Duke Energy Kentucky also provides electric service to approximately 146,500 customers in Boone, Campbell, Gallatin, Grant, Kenton, and Pendleton counties.

- Monroe, Ohio – Todhunter Resource Center
- Monford Heights, Ohio – Resource Center
- Erlanger, Kentucky – Duke Energy Kentucky's construction and maintenance facility
- Covington, Kentucky – Duke Energy Kentucky's meter reading operations

From these locations, Duke Energy Kentucky directs the planning, construction, operation, and maintenance of our natural gas transmission and distribution systems.

Q. PLEASE PROVIDE AN OVERVIEW OF THE DUKE ENERGY CORPORATE AND BUSINESS STRUCTURE.

A. Duke Energy is one of the largest utility companies in the United States. Through a series of mergers and acquisitions, including the 2006 merger with Cinergy, the 2012 merger with Progress Energy, and the more recent merger with Piedmont Natural Gas Company (Piedmont), Duke Energy now serves approximately 7.9 million electric customers in Kentucky, Ohio, Indiana, North Carolina, South Carolina, and Florida, and 1.6 million natural gas customers in Kentucky, Ohio, North Carolina, South Carolina, and Tennessee, representing a population of over 24 million in seven states.

Q. PLEASE DESCRIBE HOW BEING A PART OF THE DUKE ENERGY FAMILY OF COMPANIES ASSISTS DUKE ENERGY KENTUCKY IN PROVIDING SAFE, RELIABLE, ADEQUATE, REASONABLE, AND AFFORDABLE NATURAL GAS SERVICE TO ITS KENTUCKY CUSTOMERS.

A. As further explained by Duke Energy Kentucky witness Jeffrey R. Setser, Duke Energy Kentucky is a party to multiple Commission-approved affiliate service agreements that provide the Company with access to a vast level of resources, experience, and expertise beyond what Duke Energy Kentucky could achieve as a stand-alone utility.[2] These various agreements include, among other things, a service company/operating company agreement and an operating company agreement. Under the former, Duke Energy Kentucky and, by extension, our customers, benefit from the defined pool of expert services of attorneys, accountants, engineers, customer service representatives, and other professionals whose time and cost is shared among all utility affiliates within Duke Energy. Under the latter agreement, Duke Energy Kentucky and our customers benefit from the services provided by affiliated utility companies that furnish natural gas and/or electric service in seven states.

The merger with Piedmont brought additional operational experience from the natural gas industry. The Duke Energy Natural Gas Business Unit now consists of many legacy Piedmont leaders who have industry-leading experience

[2] The Commission approved these services agreements in Case No. 2005-00228, involving the Duke Energy/Cinergy merger, again in Case No. 2011-00124 involving the merger between Duke Energy and Progress Energy, and most recently in Case No. 2016-00312 to incorporate Piedmont as an affiliate party to these agreements.

in safely managing natural gas systems. In addition to the Kentucky and Ohio natural gas operations, the Duke Energy natural gas system now includes 24,450 miles of distribution lines and approximately 2,841 miles of transmission lines in North Carolina, South Carolina, and Tennessee.

Because of these approved affiliate agreements, Duke Energy Kentucky's customers have access to vast resources, including a highly trained and dedicated workforce from multiple jurisdictions, that are familiar with the Company's systems and are experienced in the safe operation of the Company's utility infrastructure, thereby enabling the continued and efficient operation of Duke Energy Kentucky's natural gas utility system. Pursuant to Commission-approved service agreements, Duke Energy Kentucky is allocated only a portion of these costs. Although this structure affords significant benefit to our customers, it is not a structure with which they have reason to take notice. Indeed, the legal entity structure and relationships discussed above are essentially invisible and seamless to our Kentucky customers, who receive all of their utility services from Duke Energy Kentucky. This corporate structure is designed such that our Kentucky customers will continue to receive the high-quality natural gas service they expect, without regard to corporate structure or organization.

B. COMMUNITY ENGAGEMENT

Q. PLEASE GIVE AN OVERVIEW OF DUKE ENERGY KENTUCKY'S ECONOMIC DEVELOPMENT ACTIVITIES.

A. Duke Energy Kentucky embraces our responsibility to promote economic development in the communities in which we do business. We appreciate that access to affordable, reliable utility service is a critical factor in a company's decision about where to locate or expand its facilities and Duke Energy Kentucky is well positioned to meet our customers' energy needs and attract job-creating industry and capital investment to our service territory. However, business clients need more than reliable utility service. They also need readily available building sites, access to state and local incentives, flexible workforce training programs, and proximity to a community of customers and business partners. Duke Energy Kentucky assists in meeting these needs through our partnerships with our local communities and the Commonwealth of Kentucky.

In 2020, Site Selection Magazine named Duke Energy to its list of Top Utilities in Economic Development for North America for the sixteenth consecutive year. This prestigious list represents the top 1 percent of all utility providers in the country receiving this designation. Site Selection Magazine has recognized Duke Energy's "Site Readiness" program as a best practice. This program is designed to improve large tracts of industrial land in the service territory, moving them closer to being "fully marketable." Duke Energy pays for a national site consultant to conduct the site evaluation and due diligence and to prepare a robust, comprehensive report that provides recommendations on site improvements and targeted industries to attract, along with labor statistics tied to the site. A local engineering firm secured by Duke Energy provides a detailed analysis of the site's streams, wetlands, topography, and soils and conceptual drawings for how many acres are actually developable. The program also helps the local community and economic development professionals hone their skills around the highly competitive process of responding to requests for proposals from site consultants and prospects. Since 2010, Site Readiness has been conducted with sixteen sites in our Duke Energy Kentucky footprint; five of which have seen substantial development, including the Amazon Air Hub facility in Boone County and a sixth site tied to a recent announcement for development plans for a 270-acre site. Eight of the sixteen are still being actively marketed by Northern Kentucky Tri-ED. In addition to this successful program, our economic development team collaborates with local, regional, and state economic development professionals in attracting new business and jobs to our communities, whether in the field of manufacturing, technology, healthcare, logistics, distribution, or professional services.

Duke Energy Kentucky's strategic partnerships and board memberships with local and regional economic development efforts such as with the Regional Economic Development Initiative (REDI) Cincinnati and Northern Kentucky Tri-ED, combined with Duke Energy Kentucky's competitive rates, have resulted in a number of economic development successes in Northern Kentucky.

We estimate that our cooperative efforts, along with those of state and local economic development officials, have contributed to the creation of nearly 31,000 new Northern Kentucky jobs and more than $4.8 billion of capital investment in Northern Kentucky since 2006.

Duke Energy Kentucky's employees actively serve on several boards and committees of organizations in the community that promote economic development in the region. Some of these organizations include:

- Catalytic Funding Corp. of Northern Kentucky
- Cincinnati USA Regional Chamber of Commerce
- Cincinnati Business Committee
- Cincinnati Center City Development Corporation
- Cintrifuse
- European American Chamber of Commerce
- Gateway Community & Technical College
- GROW NKY
- Horizon Community Funds of Northern Kentucky
- Kentucky Chamber of Commerce
- Kentucky Association of Economic Development
- NKY Workforce Investment Board
- Northern Kentucky Tri-ED
- Northern Kentucky Chamber of Commerce
- OneNKY Alliance
- REDI Cincinnati

Q. DESCRIBE DUKE ENERGY KENTUCKY'S CHARITABLE GIVING PHILOSOPHY.

A. Duke Energy Kentucky has made good corporate citizenship a priority by giving back to the communities we serve. Since 2018, Duke Energy Kentucky and the Duke Energy Foundation have contributed approximately $1.8 million in shareholder dollars to Kentucky charitable organizations. But our contributions are not only financial in nature. Rather, consistent with the culture of Duke

Energy, our employees and retirees and their families regularly give back to our communities by volunteering their time. Indeed, during 2019 alone, we had nineteen volunteer events in Kentucky where employees and retirees and their families volunteered over 3,580 hours of their time. During 2020, despite the impacts of and constraints due to COVID-19, Duke Energy employees and alumni collectively volunteered over 1,100 hours.

Q. DESCRIBE THE METHODS EMPLOYED BY DUKE ENERGY KENTUCKY TO ENGAGE WITH CUSTOMERS.

A. Our customers depend on the services we provide to power their lives. In this very diverse and dynamic environment, it is important that our customers are able to engage with Duke Energy Kentucky via a variety of platforms. To enable these opportunities to interact, the Company offers the following customer service channels:

- Automated Phone Service
- Business Service Center
- Contact Centers
- Enhanced Web Functionality for Online Services
- Focus Groups for small/medium businesses
- Pay Agents

Q. DO CUSTOMERS HAVE OPTIONS FOR BOTH MANAGING AND PAYING THEIR BILLS?

A. Yes. Duke Energy Kentucky has a number of programs designed to allow customers to conveniently manage their bills:

- Adjusted Due Date: This program offers customers more control over when they pay their energy bill by adjusting their due date forward by up to ten business days from their original due date at no charge.
- Budget Billing: This program provides customers with predictable monthly payments and better control over their energy spending, which eases planning and budgeting. Customers who sign up for the free Budget Billing program may choose from two plans that adjust periodically based on actual energy usage. The Annual Plan provides eleven months of equal payments with a settle-up in the twelfth month, while the Quarterly Plan provides a quarterly review and adjustment of the budget billing amount, preventing a settle-up month.
- Duke Energy Mobile App: Duke Energy has a new mobile app for iPhone and Android devices through which customers can manage their account, pay bills, report outages, and take advantage of products and services offered by Duke Energy.
- Extended Payment Agreements: Customers have the option of entering into an Extended Payment Agreement with the Company. For example, if a customer received a disconnection notice and was unable to pay prior to the planned disconnection date, they may set up the account for an extended payment agreement and continue service without interruption.
- High Bill and Usage Alerts: Duke Energy Kentucky auto-enrolls all eligible non- advanced metering infrastructure (AMI) metered

customers in our High Bill Alert program. Customers in this program are alerted at mid-cycle when their bill is projected to be 30 percent and/ or $30 higher than the previous month based on weather and twelve months of historical usage. Duke Energy transitions all eligible customers who receive an AMI certified meter from our High Bill Alert to our Usage Alert program, which uses interval data to calculate electricity cost. Customers on our Usage Alert program automatically receive an email at the midpoint of their billing cycle with their current electricity cost broken down by appliance and projected cost. These customers can also select a dollar amount to receive budget alerts. Eligible customers who start service at premises with an AMI-MDM certified meter are automatically enrolled in our Usage Alert program.

- Paperless Billing: This program allows customers to receive a bill-ready reminder via email and then view and pay their bill online at duke-energy.com or our mobile app, negating use of our standard paper bill that is mailed to the customer.
- Payment Confirmations: All email-registered customers are automatically enrolled to receive an email when their payment is received. Customers can choose to receive payment notifications via text message by updating their online account preferences.
- Pick Your Due Date: Residential and non-residential customers with advanced metering infrastructure meter data management-managed (AMI-MDM) meters are eligible for the Pick Your Due Date program.

These customers may have their billing cycle changed to align with their desired due date free of charge.

- WinterCare: This program is designed to provide heating assistance to those in need. The WinterCare program is administered in partnership with the Northern Kentucky Community Action Commission and uses federal low-income guidelines, as well as true need, to determine program eligibility. Residential customers who are eligible for WinterCare may receive assistance of up to $300 per program year.
- Home Energy Assistance (HEA): This program provides another source of relief for customers in need. Consistent with the Commission's statewide investigation into utility home energy assistance programs in Case No. 2019-00366, this program provides eligible customers (up to 200 percent of the federal poverty level) with much needed monthly bill assistance. Specifically, eligible customers may receive up to $693 in bill assistance broken down as follows:
    - Combination electric and gas customers can receive up to $99 per month between January-April and July-September.
    - Gas-only customers can receive $173.25 per month between January and April.

This program is funded through a combination of customer charges and shareholder contributions, and managed by Community Action Kentucky, Inc., and locally, its subcontractor, the Northern Kentucky Community Action Commission.

Although customers can pay their bills using the United States Postal Service, they also have other options. The Company offers several convenient bill payment options, which include:

- Automatic Bank Draft: This program allows customers to have their monthly charges auto drafted from their personal checking or savings account at no cost.
- Auto Pay: The Auto Pay function is a free service for customers enrolled in Paperless Billing and provides online access to either make a one-time payment or cancel or edit any scheduled future payments.
- Email Bill Delivery: Residential and non-residential customers who enroll in Email Bill Delivery are provided with a secure PDF copy of their bill via email. Once enrolled, the customer receives their bill as an offline email attachment, which can be accessed and paid through any electronic device, including mobile devices. Customers do not have to be enrolled in Paperless Billing to be eligible for this program.
- Online and Mobile App payments via Speedpay: Customers may make a one-time, same-day payment online or by phone using a credit card, debit card or electronic check, which applies the payment to the account immediately. Currently, a fee of $1.50 for residential accounts and $8.50 per non-residential account transaction up to $10,000 applies to each payment. For payments more than $10,000, the convenience fee is 2.75 percent of the amount paid.

The third-party fees cover the processing cost associated with handling credit card and electronic debit payments.

- Paperless Billing: Customers may enroll in a Paperless Billing option, allowing them to receive and, if they choose, to pay their bill online at no cost.
- Pay Agent Network: There are over sixty locations in the Duke Energy Kentucky service area where customers can make cash, check, or money order payments. These locations are found in establishments where customers typically conduct other business, such as grocery stores, pharmacies, convenience stores, and larger retailers.

Q. PLEASE DESCRIBE THE ACTIONS DUKE ENERGY KENTUCKY HAS TAKEN DURING THE COVID-19 PANDEMIC TO ASSIST ITS CUSTOMERS.

A. The Company was proactive in swiftly responding to the COVID-19 pandemic in order to assist our customers and ensure that we were able to continue providing the high-quality natural gas service that our customers expect. These proactive, temporary actions included, but were not limited to:

- Suspending disconnections for non-payment and assessment of late payment fees for all customers;
- Waiving assessed third-party credit and debit card fees for customers who wished to pay their Duke Energy utility bill by credit or debit cards during initial months of the pandemic;

- Offering flexible payment arrangements in advance of the Commonwealth's moratorium on disconnections being lifted and automatically enrolling customers with existing arrearages into extended payment plans once standard billing practices resumed, protecting customers from disconnection;
- Suspending inside natural gas piping inspections, except in emergency situations to limit personal contact and mitigate social spread;
- Establishing new protocols and training for employees for using personal protection equipment and for interactions with customers, including in-person health assessments prior to entering into a customer home and call-ahead appointments; and
- Suspending in-home, non-essential work activities, such as energy efficiency assessments, to limit contact and promote social distancing.

In addition, in response to Commission directives, the Company continued to suspend disconnections through December 2020 and placed all customers with arrears (through their October 2020 billing cycle) on a default seven-month payment plan. The Company placed approximately 16,280 accounts on a deferred payment plan arrangement in October 2020. The Company also monitored customer accounts for those customers who had previously established a deferred payment agreement. In the event a customer subsequently defaulted, they were automatically enrolled in a new, six-month deferred payment plan. Further, in addition to the ten-day written notice provided to customers in advance of disconnections for non-payment, the Company provides additional notices to customers, including call and text campaigns approximately forty-eight hours before the disconnection is scheduled and day of disconnection call and text campaigns.

C. CUSTOMER SATISFACTION

Q. HOW DOES DUKE ENERGY KENTUCKY MEASURE PERFORMANCE FOR PROVIDING HIGH QUALITY CUSTOMER SERVICE?

A. Duke Energy Kentucky strives to consistently provide high quality customer service. Duke Energy developed and implemented an ecosystem of customer satisfaction measurement tools to understand and identify pain points in the current customer experience, as well as provide prioritized investment and improvement guidance to design new satisfying experiences. We currently measure customer satisfaction performance through a combination of internal, proprietary tools, as well as the annual J.D. Power Natural Gas Utility Residential Customer Satisfaction Study (J.D. Power Study), which provides an overall industry benchmark.

Q. PLEASE DESCRIBE THE J.D. POWER STUDIES AND DUKE ENERGY KENTUCKY'S PERFORMANCE UNDER THOSE STUDIES.

A. J.D. Power is a well-known measure of consumer opinion and customer satisfaction in many key industries. J.D. Power annually surveys natural gas utilities' residential customers regarding their overall satisfaction with their utility, as well as key areas of their relationship. Duke Energy Midwest (Kentucky and Ohio) participates in these annual natural gas utility studies.

The J.D. Power Study calculates overall customer satisfaction based on six performance areas: (1) safety and reliability; (2) billing and payment; (3) price and value; (4) corporate citizenship; (5) communications; and (6) customer service. J.D. Power published the results of its 2020 Natural Gas Utility Residential Customer Satisfaction Study in September 2020. Duke Energy Midwest has seen steady improvements in its score, up another five points in 2020 – continuing a trend of improving scores in each of the past four years – with scores up twenty-seven points since 2017. Attachment ABS-1 includes the 2020 J.D. Power Natural Gas Residential Satisfaction Study.

These results highlight the improvements resulting from our internal voice of the customer program. The actions we have taken to improve customer sentiment as measured by our internal proprietary studies have also driven increases in our J.D. Power scores. We will continue to use this feedback to improve the customer experience.

Q. PLEASE DESCRIBE THE COMPANY'S PROPRIETARY CUSTOMER SATISFACTION MEASUREMENT PROGRAM AND PERFORMANCE.

A. As previously mentioned, the Company has built an ecosystem of customer satisfaction measurement tools:

- **CX Monitor (CXM)** is Duke Energy's proprietary relationship study and is administered annually to all customers for whom we have a valid email address. It enables understanding of customer sentiment based on overall experience as well as key experiences that customers may have had with us in the past twelve months, including 'Billing &

Payment,' 'Reliability,' 'Communications,' 'Call,' and 'Web.' All customers provide a score for relevant experiences on a '0-10' scale and provide open-end verbatim comments detailing the primary reason(s) for their score, enabling analysis to prioritize investment. Duke Energy Kentucky Residential Gas has seen steady improvement in overall customer sentiment scores with strong year-over-year performance through the end of 2020.

- **Fastrack 2.0** is Duke Energy's proprietary transaction measurement program, measuring the quality of key experiences customers have within 24 to 48 hours of their work requests being closed. Fastrack 2.0 uses an email survey that is sent to customers form whom we have a valid email address. Satisfaction is measured on a '0-10' scale, with Net Satisfaction (Net Sat) serving as our key measure. Experiences being measured include 'Start/Transfer Service,' and 'Smell Gas,' with Net Sat very strong at ~72% and ~81% respectively in 2020. Fastrack serves as another valuable tool to understand where there may be opportunities to improve these two experiences.

Finally, Duke Energy implemented the **'Reflect'** program (***Reflect-Web*** in 2019, and ***Reflect-Call*** in mid-2020), a post-contact survey that gathers feedback after a customer contacts Duke Energy by web or call. These tools help provide critical feedback to improve key channels customers use to contact Duke Energy, with results improving (web) or relatively high (call) in 2020. Confidential

Attachment ABS-2 contains an Overview of Duke Energy Kentucky's CSAT performance.

D. DEVELOPMENTS SINCE THE COMPANY'S LAST NATURAL GAS RATE CASE

Q. PLEASE SUMMARIZE THE SIGNIFICANT OPERATIONAL DEVELOPMENTS AND INVESTMENTS THAT HAVE OCCURRED SINCE THE 2018 RATE CASE.

A. In 2020, Duke Energy Kentucky placed in service the first phase of the UL-60 natural gas pipeline. Additionally, since our last natural gas rate case, the Company has made investments needed to respond to controlling pipeline safety regulations and evolving customer expectations. These investments are discussed in greater detail below and by other witnesses in this proceeding.

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S UL-60 PIPELINE.

A. The UL-60 pipeline is approximately seven miles in length and twenty-four inches in diameter. It is a steel pipeline through which natural gas will flow – north to south – across the central part of the Company's service territory. The pipeline will connect two existing pipeline segments on the Duke Energy Kentucky natural gas delivery system, namely, UL03 and AM07. The project also includes four pressure regulating stations. As further explained by Company witness Brian Weisker, the UL-60 pipeline will create necessary capacity for the Duke Energy Kentucky natural gas delivery system in order to meet new load and increased demand and provide greater reliability to the overall system, thereby benefitting all of the Company's natural gas customers. The project will also provide additional feeds to the gas delivery system to support continued growth in

Northern Kentucky and will provide system flexibility to back-feed portions of both the UL03 and AM07 pipelines in the event of scheduled or emergency work.

Q. PLEASE BRIEFLY DISCUSS THE NEED FOR CONTINUING INVESTMENTS IN THE DISTRIBUTION SYSTEM.

A. Duke Energy Kentucky has regularly made prudent investments in our natural gas delivery system, as needed for its continued safe, reliable, and efficient operation. And, over the years, the system has evolved, consistent with applicable standards, changes in technology, and, importantly, changes in our customers' expectations. Our investments and the manner in which they are made have thus also evolved. The Company continues to explore strategies and opportunities to make prudent investments to improve not only the performance of our natural gas delivery system, but also how we interact directly with our customers. These strategies involve examination of new operational technologies including, but not limited to, in-line inspections, metering infrastructure, and additional communication platforms.

In addition, as further explained by Mr. Weisker, ever-evolving federal regulations prompt investments to enable the continued safe and reliable operation of the natural gas system. These projects are included in the Company's Distribution and Transmission Integrity Management Plans. Finally, additional investments are being made that will further enhance customers' overall experience with Duke Energy Kentucky.

Q. PLEASE ELABORATE ON THESE ADDITIONAL INVESTMENTS.

A. Duke Energy Kentucky will be converting our existing customer information system (CIS) to a new, state of the art system. This software investment will occur over time and is currently planned to be fully in service in the spring of 2022 as part of a consolidated Duke Energy effort to modernize the customer experience in all jurisdictions and provide greater flexibility and efficiency in meeting ever-evolving customer expectations. Duke Energy Kentucky's current CIS' primary function, as designed, was to use the aggregated usage data for simple billing purposes for each individual meter. The utility industry, however, is not now limited to such simplistic transactions as customers desire more information to better understand and control their energy consumption.

Advanced meters and associated components, for example, have the capability of recording more frequent and detailed usage data. This data, in turn, can create personalized opportunities for customers according to their preferences, whether in the form of rate options or other usage-related services. Duke Energy Kentucky intends to continue transforming our natural gas utility service in order to position our customers to have more control, convenience, and information as well as flexible billing options. A more robust and capable CIS is necessary to enable the Company to meet customer expectations for greater convenience, control, transparency, and access to information.

Further, Duke Energy Kentucky continues to invest in our infrastructure, commensurate with our responsibility to provide safe, reliable, reasonable, adequate and affordable natural gas service. A variety of factors require that these investments be made, including new customer growth, economic development, and governmental mandates. Importantly, governmental mandates necessitate proactive measures to enable compliance with applicable law, including safety standards. As warranted by applicable safety standards, such proactive measures include system upgrades and infrastructure replacement. As I explain further below, because of the dynamic nature of the regulation, the Company is proposing Rider GMA to respond to the regulations issued by the U.S. Department of Transportation, Federal Pipelines and Hazardous Materials Safety Administration (PHMSA).

Q. NOTWITHSTANDING THE CHANGES YOU PREVIOUSLY MENTIONED, DO YOU BELIEVE DUKE ENERGY KENTUCKY SUCCESSFULLY MANAGED ITS COSTS OF PROVIDING SERVICE TO CUSTOMERS SINCE ITS 2018 RATE CASE?

A. Yes. Duke Energy Kentucky has proven successful in and capable of implementing initiatives to manage our costs to serve customers. As explained by Ms. Lawler, the Company's operations and maintenance (O&M) expense has actually remained relatively stable over the last twelve years. Duke Energy Kentucky's base rate proceeding is driven by needed capital investments.

Although the Company has been diligent in controlling O&M expense over an extended time, we have had to make significant investment in our natural gas system. As a result, the Company must seek an increase in natural gas base rates in order to have the opportunity to earn a fair and reasonable return.

III. OVERVIEW OF DUKE ENERGY KENTUCKY'S RATE CASE

Q. PLEASE EXPLAIN WHY DUKE ENERGY KENTUCKY PROPOSES TO INCREASE RETAIL NATURAL GAS BASE RATES.

A. Duke Energy Kentucky's natural gas base rates were last updated in 2018 and went in effect in 2019. Those rates are no longer sufficient to cover our cost of service and do not provide an opportunity to earn a fair rate of return on investments. There is a need to adjust rates to reflect the changes in cost of service related to increased capital investments for our natural gas infrastructure. Although the Company has added customers over time and consumption is modestly higher today than just a few years ago, these factors do not offset the increases in depreciation and property tax costs related to recent capital investment in our natural gas delivery system and the associated return on and of those investments as described in the testimony of Ms. Lawler. These factors have prompted the Company to propose new rates, as reflected in this proceeding.

Q. PLEASE GENERALLY DESCRIBE DUKE ENERGY KENTUCKY'S PROPOSED NATURAL GAS RATE INCREASE.

A. Duke Energy Kentucky proposes to change our natural gas base rates in order to increase annual natural gas base rate revenues by approximately $15 million. This increase is driven by investments in plant in service that have occurred since the 2018 Rate Case and that are forecasted to be completed during the proposed test period. This rate increase is necessary in order to allow Duke Energy Kentucky to recover our costs for providing the high-quality natural gas service that our customers expect and have the opportunity to earn a fair return on our capital investments.

Q. WHAT TEST PERIOD IS THE COMPANY USING IN THIS PROCEEDING?

A. Duke Energy Kentucky is using a forecasted test period that spans the twelve months ending December 31, 2022. Duke Energy Kentucky witness Abby L. Motsinger explains how the Company determined the basis for the forecasted test period.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED RIDER GMA.

A. Duke Energy Kentucky is proposing to implement Rider GMA as part of this proceeding. The rider corresponds to the Company's obligation to adhere to governmental directives or mandates impacting the utility that are outside of our control. These mandates include changes in federal or state tax rates and those promulgated by federal governmental entities and agencies that require the Company to upgrade or replace our natural gas delivery infrastructure. Rider GMA would act as either a credit or a charge to customers, depending upon the impact of the governmental mandate and would be will be applicable to all-natural gas customers.

Q. PLEASE PROVIDE EXAMPLES OF THE TYPES OF TAX-RELATED GOVERNMENTAL MANDATES ELIGIBLE FOR INCLUSION IN RIDER GMA.

A. As this Commission is aware, in 2017, as part of the Tax Cuts and Jobs Act, the Trump Administration reduced the federal corporate income tax rate from 35 percent to 21 percent. This prompted customers to initiate proceedings before the Commission to implement these changes outside of a base rate proceeding.[3] Likewise, the Kentucky General Assembly initiated its own reduction to state taxes.[4]

Now, at the time of the filing of this application, the new Biden Administration has indicated a desire to increase that federal tax rate.[5] The impacts of such a change are presently unknown and thus cannot be included in this application. However, such a change is likely to occur during the pendency of this case and be implemented after the resolution of this proceeding. Given probable continuing changes in applicable tax rates, a mechanism such as Rider GMA would allow the efficient adjustment – either as a credit or a charge to customer rates – and confirm that the Company is collecting no more and no less than what we are required to collect in taxes. Notably, through a discrete mechanism, customers will benefit from any governmental mandates that produce credits, such as tax reductions.

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[3] *In the Matter of Kentucky Industrial Utility Customers, Inc., v. Duke Energy Kentucky, Inc.,* Case No. 2018-00036, (Order)(January 25, 2018); *See also,* (Order)(October 31, 2018): the Commission approved a non-unanimous settlement resolving the issues created by the Tax Cuts and Jobs Act and implementing rate adjustments, including creation of a new rider.

[4] H.B. 487 became law on April 27, 2018 implementing a flat 5 percent income tax rate for individuals and corporations. Available at: https://revenue.ky.gov/News/PublishingImages/Pages/DOR-Outreach-and-Education/2018%20KY%20Income%20Tax%20Changes-13NOV18.pdf ; Last accessed May 7, 2021.

[5] *See:* https:// www.whitehouse.gov/briefing-room/speeches-remarks/2021/05/06/remarks-by-president-biden-on-the-american-jobs-plan-3/ ; describing reducing the current tax cut to between 25 and 28 percent. Last accessed May 7, 2021.

Q. PLEASE DESCRIBE THE PIPELINE SAFETY-RELATED INVESTMENTS THAT COULD BE ELIGIBLE FOR INCLUSION IN RIDER GMA.

A. Mr. Weisker further details the PHMSA regulations necessitating investments in our natural gas infrastructure. But generally speaking, the regulations applicable to natural gas pipeline safety continue to evolve, with PHMSA routinely promulgating new regulations and interpreting existing regulations, both actions intended to further enhance and enable the safety of the natural gas delivery systems throughout the country. As a prudent operator, the Company responds to, and complies with, changes in controlling regulations. Doing so demands testing of and, in many cases, upgrade and replacement of existing infrastructure. The proposed Rider GMA mechanism would allow the Company to recover for these mandated investments in a way that mitigates rate volatility for customers.

Q. DOES KENTUCKY LAW SUPPORT THE COMPANY'S RIDER GMA?

A. I believe it does. KRS 278.509 confirms the Commission's authority to approve pipeline replacement programs upon application by a utility for recovery of such replacements that are not currently in base rates.[6] Indeed, the Accelerated Main Replacement Program and the Accelerated Service Line Replacement Program, both of which enhanced the safety and integrity of the Company's natural gas delivery system, were Commission-approved pipeline replacement programs with discrete recovery mechanisms. As Mr. Weisker explains, PHMSA rules, including new provisions of the "Mega-Rule," will require the Company to replace aging

[6] KRS 278.509

infrastructure to meet new safety and integrity thresholds. While Duke Energy Kentucky is not requesting approval of any such projects as part of this proceeding, such investments are imminent. The Company is merely seeking the creation of the mechanism in this case and the Commission and other interested stakeholders will have the ability to review and consider projects through separate Certificate of Public Convenience and Necessity (CPCN) applications and/or requests for inclusion in Rider GMA.

The pipeline replacement projects contemplated for inclusion in Rider GMA that do not constitute an ordinary extension of the existing system in the course of business will occur with Commission authorization through a CPCN in accordance with KRS 278.020. These investments, proposed as part of a future CPCN, will be placed into service outside of the test year in this proceeding. Therefore, the proposed mechanism would alleviate the need for multiple successive rate cases to bring these new facilities into rates over the coming years and provide a streamlined and less volatile impact to customer rates as compared to base rate proceedings. Any assets brought into service and included in Rider GMA will be adjusted for taxes and depreciation until such time as the Company files a base rate proceeding to reset the mechanism.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED RIDER GMA PROCEDURE.

A. Company witness Lawler further details the Company's Rider GMA proposal in her Direct Testimony. In summary, upon approval of the tariff and mechanism in this case, Duke Energy Kentucky will file a separate application to implement any adjustments to the Rider GMA in response to a governmental mandate, such as those relating to tax changes or pipeline replacement projects. These applications will be subject to Commission determination of reasonableness. The Company will maintain the burden of demonstrating that charges or credits flowing through via Rider GMA are not currently reflected in base rates and are recoverable. Significant pipeline replacement projects that do not constitute an ordinary extension of the existing system in the ordinary course of business (*e.g.*, PHMSA-required pipeline replacements and upgrades) will be accompanied with a CPCN. Once approved, the Company will implement Rider GMA in customer rates. Going forward, Rider GMA will be subject to an annual true-up and reconciliation to ensure the Company is neither over- nor under-collecting for these mandates. Rider GMA will be reset to zero as part of a future base rate case proceeding.

Q. DO YOU BELIEVE THE COMPANY'S APPLICATION FOR AN INCREASE IN NATURAL GAS BASE RATES IS REASONABLE?

A. Yes. As further explained by Ms. Lawler, the Company has done an excellent job managing its costs of providing safe, reliable, reasonable, adequate and affordable natural gas service. The drivers of this case are necessary capital investments that have occurred since the last rate case.

IV. INTRODUCTION OF WITNESSES

Q. PLEASE INTRODUCE THE OTHER WITNESSES IN THIS PROCEEDING.

A. I identify below the other individuals who will present testimony on behalf of Duke Energy Kentucky, as well as the subject matters of their respective testimony:

- Chris R. Bauer, Director, Corporate Finance, and Assistant Treasurer, discusses the Company's credit ratings, financial objectives, cash requirements, and capital structure;
- Jay P. Brown, Director, Rates and Regulatory Planning, provides testimony supporting Duke Energy Kentucky's overall revenue requirement for the test period and certain adjustments to the test period financial data;
- Dylan W. D'Ascendis, Director, Scott Madden Associates, offers testimony on Duke Energy Kentucky's requested rate of return;
- Retha I. Hunsicker, Vice President, Customer Connect Solutions, offers testimony regarding the Company's new CIS;
- Jeff L. Kern, Rates and Regulatory Strategy Manager, offers testimony as to rate design and tariff language;
- Bryan T. Manges, Director, Gas Utility & Infrastructure, offers testimony regarding the Company's accounting policies and the accounting treatment requested in these proceedings;

- Abby L. Motsinger, Director, Jurisdictional Forecasting, offers testimony supporting Duke Energy Kentucky's budgeting and forecasting processes and sponsors certain forecast information used for the test period financial data;
- Sarah E. Lawler, Vice President, Rates and Regulatory Strategy OH/KY, provides a detailed overview of the filing;
- David G. Raiford, Manager Accounting, offers testimony on Duke Energy Kentucky's capital accounting processes and sponsors certain accounting information used for the test period financial data;
- John R. Panizza, Director, Tax Operations, addresses the Company's tax expense in the test period revenue requirement;
- Benjamin Walter Bohdan Passty, Ph.D., Lead Load Forecasting Analyst, performed and supports the Company's natural gas load forecast;
- Lesley G. Quick, Vice President Strategic Planning, Governance, and Technology, discusses the Company's current customer satisfaction initiatives to further improve the customers' experience;
- Jeffrey R. Setser, Director of Allocations and Reporting, supports the Company's various service agreements and associated allocations;
- John J. Spanos, Gannet Fleming Valuation and Rate Consultants, LLC, provides testimony on Duke Energy Kentucky's latest depreciation study;

- Jake J. Stewart, Director of Compensation, supports the Company's compensation and benefits programs;
- Brian R. Weisker, Senior Vice President, Chief Operating Officer, Natural Gas, provides an overview of the natural gas operations for both Duke Energy and Duke Energy Kentucky. Mr. Weisker also discusses the Company's safety and integrity initiatives and the major investments since the 2018 Rate Case; and,
- James E. Ziolkowski, Director, Rates and Regulatory Planning, provides testimony regarding Duke Energy Kentucky's cost of service study.

V. ATTACHMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE FR 14(1) THROUGH FR 14(4).

A. These filing requirements provide for the Company to seek proposed new rates through a written Application addressing various matters, including the full name, address, and electronic mail address of the Company and set forth the facts upon which the Application is based, with a request for the order, authorization, permission, or certificate desired and a reference to the particular law requiring or providing the same. FR 14(2) applies to Duke Energy Kentucky because it is a corporation, registered to do business, and is in good standing in the Commonwealth of Kentucky. The Application submitted in these proceedings includes this information and was prepared at my direction. FR 14(3) and FR 14(4) are not applicable to Duke Energy Kentucky because it is neither a limited liability company nor a limited partnership.

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

A. FR 16(1)(b)(1) is a statement for the reason for the adjustment. As I explained above and as further explained by Ms. Lawler, the Company is proposing new natural gas base rates because the present rates reflect the cost of service from the 2018 Rate Case, which is no longer sufficient to enable the Company to furnish safe, reliable, reasonable, adequate and affordable natural gas service. Duke Energy Kentucky needs to reflect the cost of service related to increased capital investments in our natural gas delivery system that have occurred since 2019.

Q. PLEASE DESCRIBE FR 16(1)(b)(2).

A. FR 16(1)(b)(2) is the certificate of assumed name. Duke Energy Kentucky's actual legal name is "Duke Energy Kentucky, Inc." The Company has filed for the assumed name of "Duke Energy." The certificate of assumed name is provided with our filing.

Q. PLEASE DESCRIBE FR 16(1)(b)(5).

A. FR 16(1)(b)(5) is a statement that customer notice has been given in accordance with the Commission's rules. The Company is publishing notice in accordance with the Commission's regulations.

Q. PLEASE DESCRIBE FR 16(2).

A. FR 16(2) is the notice of intent submitted to the Commission at least thirty, but no more than sixty, days prior to filing the Application. The notice was filed on April 30, 2021, at my direction.

Q. PLEASE DESCRIBE FR 16(3).

A. FR 16(3) states that notice given in accordance with 807 KAR 5:001 Section 7 will satisfy notice requirements of 807 KAR 5:051, Section 2. The Company provided notice to customers in accordance with 807 KAR 5:001 Section 7.

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

A. FR 16(7)(a) is a statement of attestation from me, the utility's chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of each program. The efficiency and productivity benefits that have resulted from these programs have occurred over time and thus are reflected in the Company's budgets included in the forecasted test period in these proceedings. These programs are described below:

- Duke/Progress merger: In July 2012, Duke Energy and Progress Energy closed their merger. Duke Energy Kentucky has benefitted from the implementation of best practices and through the access to additional resources and expertise from its sister electric utilities in five other jurisdictions. The Company has benefitted from the economies of scale that naturally arise from being a part of a combined corporation with a market capitalization of nearly $79 billion.
- The various mergers that have occurred over the last several years which have resulted in numerous efficiencies and implementation of best practices. Duke Energy Kentucky regularly reports on these to the Commission through regular filings.

- The Gas Transmission and Distribution Integrity Management Programs, which are designed to enhance the safety and reliability of Duke Energy Kentucky's gas distribution service by establishing a systematic plan to perform periodic safety assessments and maintenance activities in response to new federal pipeline safety legislation, as discussed in more detail by Mr. Weisker.
- The sewer line inspection program, which is a program designed to check potential high-risk gas main installations along sewer lines as a result of local sewer districts not maintaining accurate records of the location and depths of their systems. The Company inspects gas main installations that are likely to have experienced a breach based upon premises structure elevation and main line sewer location and depth in relation to the street.
- Duke Energy Kentucky has historically offered Demand Side Management programs that provide energy efficiency services to gas and electric customers. Currently there is one program that provides benefits for gas customers, the Residential Conservation and Energy Education (Low-Income Weatherization) program. The program offers direct benefits to customers through energy efficiency education, energy use audits, and even home weatherization.

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

A. FR 16(7)(e) is a statement of attestation signed by me, the utility's chief officer in charge of Kentucky operations, that the forecast is reasonable, reliable, and made in good faith and that all basic assumptions used in the forecast have been identified and justified and the forecast contains the same assumptions and methodologies as used in the forecast for use by management and an explanation for differences that exist, if applicable, and that productivity and efficiency gains are included.

Q. PLEASE DESCRIBE FR 17(1)

A. FR 17(1) relates to public postings. Duke Energy Kentucky will post a copy of the notice and Application at our place of business and will also make available on the Company's website a copy of the public notice and a hyperlink to the Commission's website where the case documents will be available.

Q. PLEASE DESCRIBE FR 17(2).

A. FR 17(2) is the customer notice.

Q. PLEASE DESCRIBE FR 17(3).

A. FR 17(3) includes the method of notice. Duke Energy Kentucky has published notice in newspapers of general circulation. Company witness Kern supports FR 17(4), which describes required content of the notice. Duke Energy Kentucky has included all content listed in FR 17(4) in its notice.

VI. CONCLUSION

Q. WERE FR 14(1), FR 14(2), 14(3), 14(4), FR 16(1)(b)(1), FR 16(1)(b)(2), FR 16(1)(b)(5), FR 16(2), FR 16(3), FR 16(7)(a), FR 16(7)(e), FR 17(1), FR 17(2), AND FR 17(3) PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

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

A. Yes.

J.D. POWER

2020 Gas Utility Residential Customer Satisfaction Study

Topline Overview

September 2020

2020 J.D. Power Gas Utility Residential Customer Satisfaction Study

PRESS RELEASE

Gas Utility Residential Satisfaction at All-Time High Despite Pandemic, J.D. Power Finds

Gas Utility Companies and Employees Seen as First Responders, Helpers

02 September 2020

TROY, Mich.: 2 Sept. 2020 — In the face of natural disasters and the COVID-19 pandemic, gas utility companies and their workers function as perceived first responders and helpers, contributing to higher customer satisfaction, according to the J.D. Power 2020 Gas Utility Residential Customer Satisfaction Study,SM released today.

"Natural gas utility companies have put forth enormous effort to assist their customers, especially during this challenging time, by way of proactive communications on topics such as financial assistance to help educate customers," said **Carl Lepper, director of the utility practice at J.D. Power**. "The biggest change in satisfaction is seen in brand image, which means the assistance efforts have not gone unnoticed by customers, despite increased use, therefore costs."

Study Results

- East Large Segment: **New Jersey Natural Gas** (for sixth consecutive year)
- East Midsize Segment: **Elizabethtown Gas** (for sixth consecutive year)
- Midwest Large Segment: **DTE Energy**
- Midwest Midsize Segment: **Atmos Energy**
- South Large Segment: **Oklahoma Natural Gas**
- South Midsize Segment: **TECO Peoples Gas** (for eighth consecutive year)
- West Large Segment: **Southwest Gas**
- West Midsize Segment: **Intermountain Gas Company**

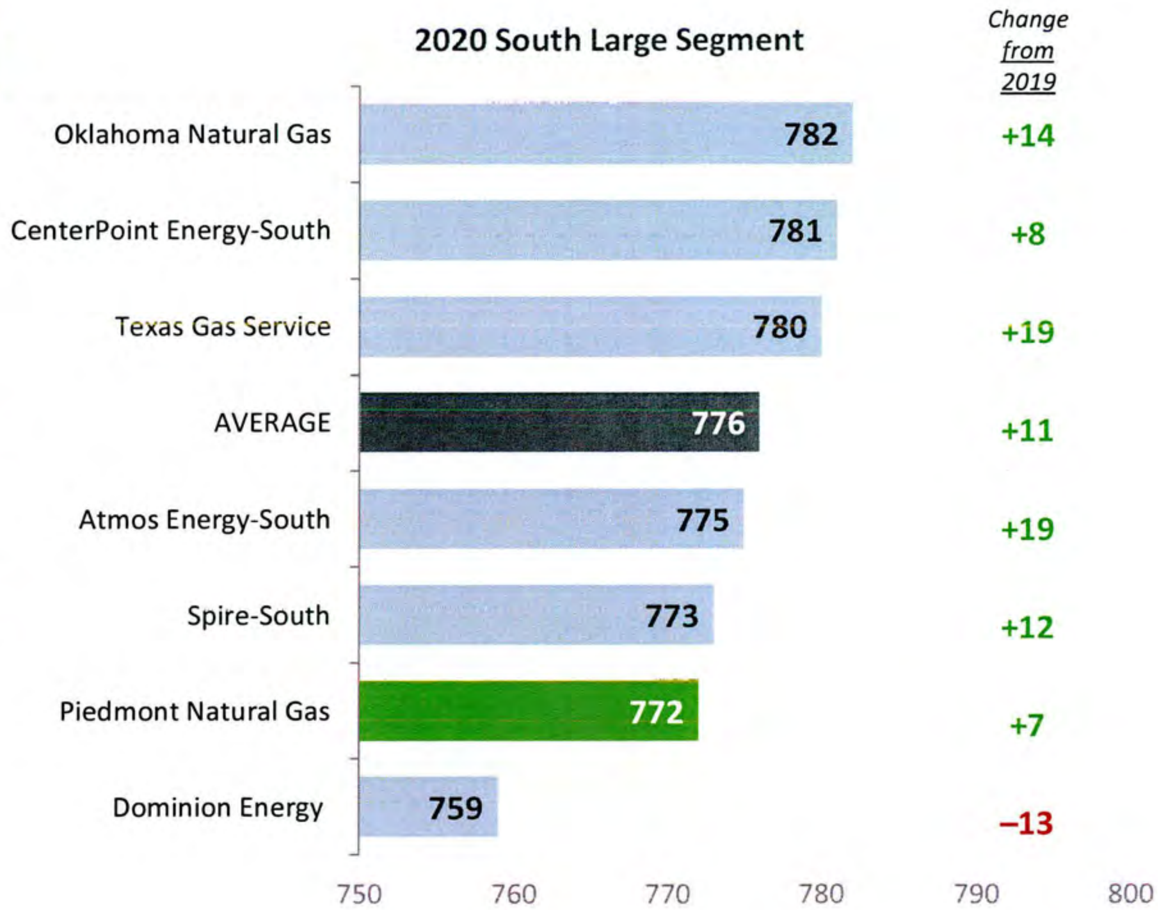
The 2020 Gas Utility Residential Customer Satisfaction Study is based on responses from 60,096 online interviews conducted from September 2019 through July 2020 among residential customers of the 83 largest gas utility brands across the United States, which represent more than 62.9 million households.

For more information about the Gas Utility Residential Customer Satisfaction Study, please visit: https://www.jdpower.com/business/resource/us-gas-utility-residential-customer-satisfaction-study

South Large Region

J.D. Power 2020 Gas Utility Residential Customer Satisfaction Study

Piedmont Natural Gas
+7 pts. year over year, slightly below the average improvement of 11 pts. in the South Large Segment.

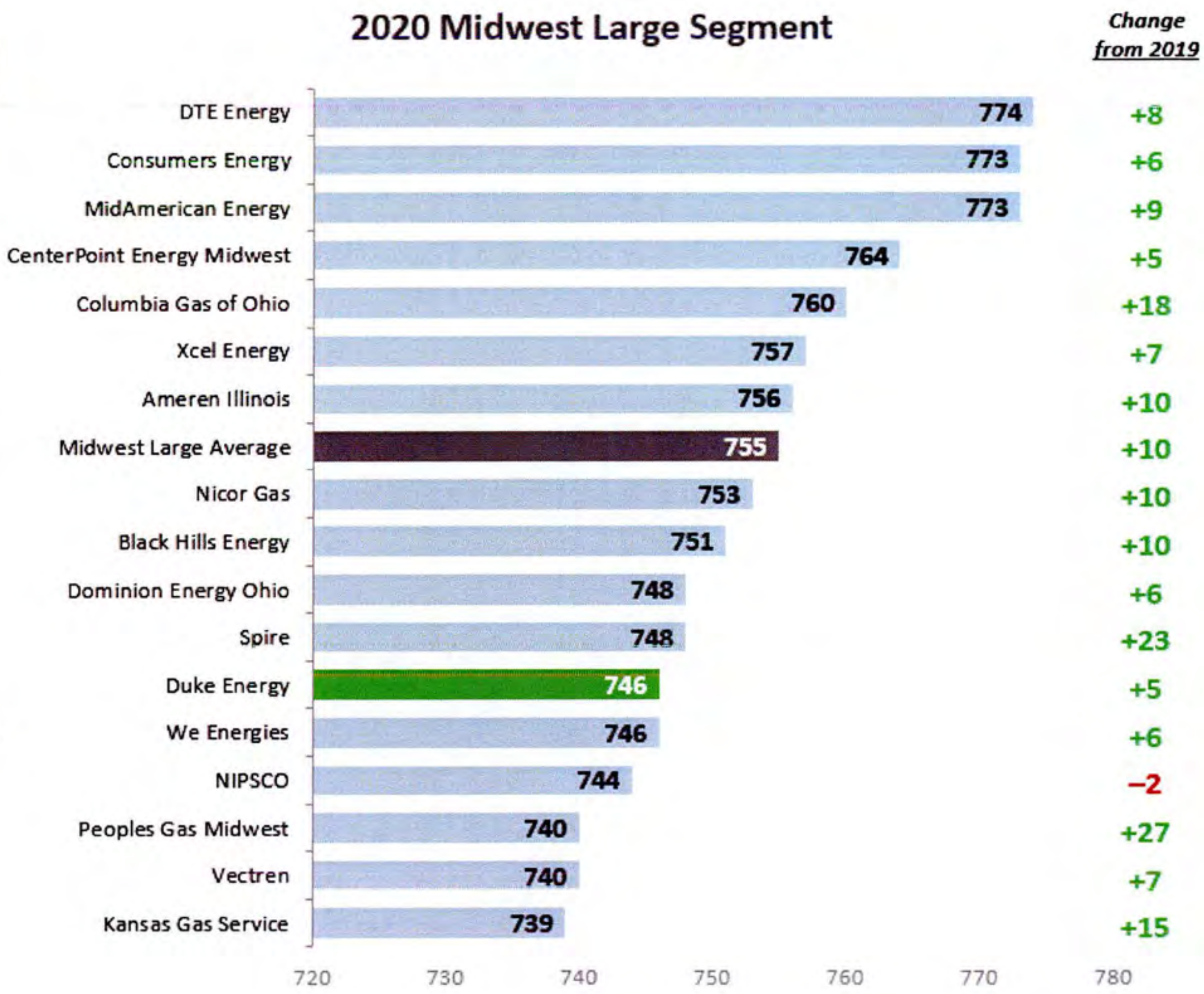


J.D. POWER

Midwest Large Region

J.D. Power 2020 Gas Utility Residential Customer Satisfaction Study

Duke Energy Midwest Gas improved again in 2020, up +5 pts. year over year, marking the fourth consecutive year of improved customer satisfaction scores, with DEMW up 27 points since 2017.



J.D. POWER

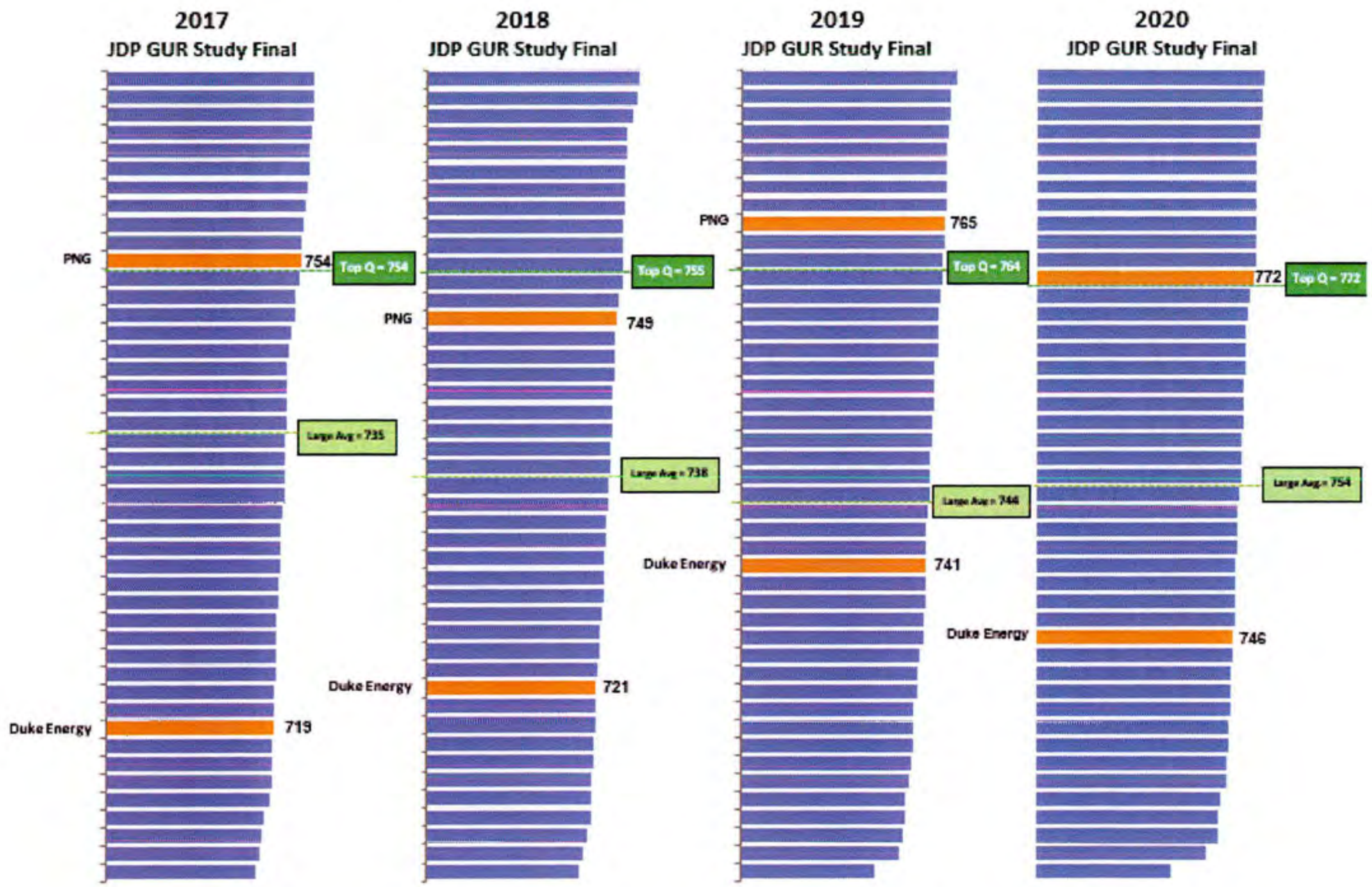
DUKE ENERGY.

J.D. Power Gas Utility Residential Customer Satisfaction Study

PNG & DEMW Gas Score Trends & Ranks

PNG & DEMW Gas CSI ranks

Among Large National Utilities



Online interviews conducted September 2016 – July 2017

Online interviews conducted September 2017 – July 2018

Online interviews conducted September 2018 – July 2019

Online interviews conducted September 2019 – July 2020

CONFIDENTIAL PROPRIETARY TRADE SECRET

ATTACHMENT ABS-2

FILED UNDER SEAL

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 Natural Gas Rates; 2) Approval of New Tariffs; and 3) All Other Required Approvals, Waivers, and Relief.	)))))	Case No. 2021-00190

DIRECT TESTIMONY OF

CHRIS R. BAUER

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

June 1, 2021

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PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Chris R. Bauer and my business address is 550 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, Corporate Finance and Assistant Treasurer. 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 received a Bachelor of Arts degree from Flagler College in 2003 and an MBA degree from the University of North Florida in 2004. I am a licensed Certified Public Accountant in the state of Florida. From 2004 to 2010, I worked in Deloitte's Audit and Enterprise Risk Services unit, providing financial statement and internal control services across various industries. In 2010, I joined Duke Energy as a Lead Audit Consultant in the Internal Audit Department. In 2015, I moved to Duke Energy's Investor Relations group where I served as a Manager responsible for communicating the company's strategic, operating and financing plan to debt and equity investors and external stakeholders. In 2017, I moved to the Treasury department and served as both a Treasury Director and the Director of Credit & Capital Markets before assuming my current role in early 2021.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS DIRECTOR, CORPORATE FINANCE AND ASSISTANT TREASURER.

A. I am responsible for financing the operations of Duke Energy and its subsidiary utilities. This includes the issuance of new debt and equity securities and obtaining other sources of external funds. My responsibilities also include financial risk management for Duke Energy and its subsidiaries. Additionally, I maintain relationships with Duke Energy's commercial banks, the fixed income investor community and the credit rating agencies.

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

A. No.

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 maintain strong credit quality. 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; sales of accounts receivable; capital lease and equipment lease information; and information relating to the 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 Ms. Abby L. Motsinger for her use in preparation of FR 16(7)(h) and Schedule K in response to FR 16(8)(k), respectively.

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 a strong, investment-grade, credit rating 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.

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 $15 million. As part of this request, supported by the analysis and testimony of Duke Energy Kentucky witness Mr. Dylan D'Ascendis, the Company is requesting an allowed return on equity (ROE) of 10.3 percent. The proposed capitalization in this request is comprised of 50.695 percent equity and 49.305 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.

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 Duke Energy Kentucky's regulatory climate, its track record for delivering on its commitments, the strength of its management team, corporate governance, its operating performance, and its service territory. Quantitative measures are primarily based on operating cash flow and focus on Duke Energy Kentucky's ability to meet its fixed obligations (interest expense in particular) on the basis of internally generated cash and the level at which Duke Energy Kentucky maintains debt balances. 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 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 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

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 or financial risk.

Q. WHEN WERE DUKE ENERGY KENTUCKY'S CURRENT CREDIT RATINGS ESTABLISHED?

A. Duke Energy Kentucky's current senior unsecured credit ratings were established by Moody's in November 1995 and by Standard & Poor's in April 2015. On December 15, 2020, S&P revised its outlook to "negative" from "stable" on Duke Energy Corp. and subsidiaries, including Duke Energy Kentucky. On January 26, 2021, S&P downgraded the senior unsecured ratings of Duke Energy Corp. and subsidiaries, including Duke Energy Kentucky to "BBB+" from "A-" and returned the outlook to "stable."

S&P utilizes a family rating methodology, whereby the credit rating and outlook of the parent company, Duke Energy Corporation, is applied to each of the parent's subsidiaries. In its January 2021 Duke Energy Corporation report,[1]

[1] S&P Global Ratings, Research Update, "Duke Energy Corp. And Subsidiaries Downgraded To 'BBB+' On Coal Ash Settlement, Outlook Stable," January 26, 2021 ("January 2021 Duke Energy Corporation Report")

S&P attributed the downgrade to weaker consolidated financial metrics primarily as a result of the coal ash settlement reached at Duke Energy Carolinas and Duke Energy Progress and Duke Energy's elevated capital expenditure plan. S&P's "stable" outlook is predicated on the expectation that Duke Energy Corp. and subsidiaries will be able to manage regulatory risk while capital spending remains high.

Moody's affirmed its Baa1 rating and stable outlook in January 2021.

Q. WHAT IS THE IMPACT TO DUKE ENERGY KENTUCKY'S EXPECTED LONG-TERM BORROWING COSTS GOING FORWARD WITH A ONE-NOTCH DOWNGRADE BY S&P AT DUKE ENERGY CORP. AND ITS SUBSIDIARIES?

A. Since the one-notch downgrade by S&P on January 26, 2021 to Duke Energy Kentucky's senior unsecured rating, there has been no material impact to Duke Energy Kentucky's credit spreads. With Moody's maintaining its "Baa1" senior unsecured credit rating on Duke Energy Kentucky, a sophisticated investor in senior unsecured bonds will evaluate the creditworthiness of that specific utility when determining the appropriate pricing level on new debt offerings. The current Baa1 rating at Moody's and the BBB+ rating at S&P are now equal ratings. Investors will typically price bonds off the lower rating when a split rating exists. For these reasons, a one-notch downgrade at Duke Energy Kentucky by S&P due solely to its family rating methodology will not likely have a meaningful impact to Duke Energy Kentucky's cost of debt going forward.

Q. WHY IS IT IMPORTANT FOR DUKE ENERGY KENTUCKY TO HAVE STRONG INVESTMENT-GRADE CREDIT RATINGS?

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 natural 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 volatility, most recently driven by COVID-19, and changes in fiscal, monetary and international trade policy. Duke Energy Kentucky must be able to finance its needs throughout such periods and strong investment-grade credit ratings provide the Company with greater assurance of continued access to the capital markets on reasonable terms during periods of volatility.

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 the previously approved weather normalization adjustment and the availability of pipeline replacement programs, such as the Company's proposed governmental mandates rider in this proceeding, which are supportive of credit quality. Generally speaking, the agencies have identified the following strengths and challenges when assessing the credit quality of Duke Energy Kentucky:

Credit Strengths:

- Financial metrics commensurate with its current ratings and stable outlook;
- Generally credit supportive regulatory environment in Kentucky; and
- Support from the Duke Energy corporate family.

Credit Challenges:

- Credit metrics are not expected to return to historic highs;
- Relatively small size compared to other integrated utilities; and
- Poorly positioned for carbon transaction risk.

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 layer, it could lead to weaker financing credit metrics and could result in a credit 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 49.305 percent debt and 50.695 percent equity, 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 Dylan D'Ascendis testifies that the Company's cost of equity is in the range of 9.98 percent to 12.68 percent. The Company supports Mr. D'Ascendis' analysis and is requesting 10.3 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. WHAT EFFECT DOES 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 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 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. 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 through different business cycles while also providing a cushion to the Company's lenders and bondholders. The Company's current and future capital expenditures require the need for a strong equity component of the Company's capital structure in order to maintain access to capital funding at reasonable terms.

Q. PLEASE SUMMARIZE THE COMPANY'S AVERAGE COST OF SHORT-TERM AND LONG-TERM DEBT FOR THE BASE PERIOD AND 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 Base and Forecast periods:

	Base Period (at August 2021)	**Forecast Period** (Avg of Dec 2021 thru Dec 2022)
Short-Term Debt (Schedule J-2)	0.623 percent	1.667 percent
Long-Term Debt (Schedule J-3)	4.033 percent	3.843 percent

For Schedule J-2, which calculates cost of short-term debt, the assumed Amount Outstanding for Sale of Accounts Receivables, for both the base and forecast period, was the average of the actual monthly balances for Duke Energy Kentucky's

Sale of Account Receivables during the trailing twelve months as of February 2021. The assumed interest rate on this debt for the base and forecast period was derived using Bloomberg's Implied forward curve for one-month London Interbank Offered Rate (LIBOR) as of February 2021 plus a 105 basis point credit spread. 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 LIBOR as of February 2021.

For Schedule J-3, which calculates the cost of long-term debt, the interest rate on $25 million of LT Commercial Paper for the base and forecast period was derived using Bloomberg's Implied forward curve for one-month LIBOR as of February 2021 plus a 25 basis point credit spread. Two long-term, senior unsecured, debt issuances one totaling $50 million and the other totaling $70 million are forecasted for September 2021 and September 2022, respectively, based on company projections. The interest rates on these future issuances were estimated using a weighted average of Bloomberg's forward curves for the 5-year, 10-year and 30-year US Treasury yield, respectively, as of February 2021 plus a 140 basis point credit spread for the 5 year debt offering, 150 basis point credit spread for the 10 year debt offering and a 175 basis point credit spread for the 30 year debt offering.

Q. DID DUKE ENERGY COMPANY TAKE ANY STEPS SINCE ITS LAST NATURAL GAS BASE RATE CASE IN 2018 TO MANAGE ITS FINANCING COSTS, THUS MITIGATING THE RATE INCREASE PROPOSED IN THIS CASE?

A. Yes. Duke Energy Kentucky has effectively managed its financing costs since the last natural gas base rate case in 2018. In that rate case, the Commission approved a weighted average cost of capital that included an average cost of long-term debt for the forecasted period of 4.360 percent. In this rate case, the average cost of long-term debt is expected to be approximately 3.843 percent. In Duke Energy Kentucky's most recent debt offering, the Company priced \$70 million of debt through the traditional private placement market. The transaction was well received by the market and achieved efficient pricing across two series of notes at a weighted-average cost of approximately 3.16 percent and a weighted average life of 20 years.

V. DUKE ENERGY KENTUCKY'S CAPITAL REQUIREMENTS

Q. WHAT ARE DUKE ENERGY KENTUCKY'S CAPITAL REQUIREMENTS DURING THE 2021-2023 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 business of Duke Energy Kentucky is projected to be approximately \$635 million during the period – 2021-2023. This amount consists of approximately \$610 million in projected capital expenditures and approximately \$25M 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. 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 70 percent of their earnings over the long run in support of these obligations.

VI. 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 March 31, 2021.

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 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, three capital leases 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 Ms. Motsinger for her 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 and statistical supplements 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 August 31, 2021, and the average of the projected balances and rates for the thirteen-month period ending December 31, 2022. 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 December 31, 2022.

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, August 31, 2021. 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 December 31, 2022.

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 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 Mr. Manges and Mr. Raiford for their use in preparing Schedule K.

VII. 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 Natural Gas Rates; 2) Approval of New Tariffs; and 3) All Other Required Approvals, Waivers, and Relief.	))))))	Case No. 2021-00190

DIRECT TESTIMONY OF

JAY P. BROWN

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

June 1, 2021

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jay P. Brown 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 Rates & Regulatory Planning. 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 degree in Business Administration with a major in Business: Finance, Investment and Banking from the University of Wisconsin - Madison. I began my career with The Alexander Companies, a real estate development company, as an Assistant Project Manager in January 2002 managing and developing real estate. Subsequently, in December 2003 I began working for Dell Inc., mainly as a Financial Analyst in Worldwide Procurement Finance, accounting for and reporting on supplier rebates. In January 2008, I began working for Bigfoot Networks, a technology start-up. I was in charge of developing distribution, online and retail channels for a new networking product. Beginning in April 2009, I also served as a Financial Advisor for Edward Jones. In June 2011, I began working as a contractor for Progress Energy and since February 2012, I have been employed by, and worked for, companies under what is now Duke Energy. The roles I've held include Sr. Business Finance Analyst and in December 2012, I took the position of Manager Nuclear Station Finance. In August of 2018, I transitioned to the Rates and Regulatory group as a Lead Rates & Regulatory Strategy Analyst, was promoted to Manager of Rates and Regulatory Strategy in January of 2020, earned a Master of Business Administration from the University of North Carolina Wilmington in July of 2020 and assumed my current role as Director of Rates & Regulatory Planning in October of 2020.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR, RATES AND REGULATORY PLANNING.

A. I am responsible for the preparation of financial and accounting data used in retail rate filings and various other rate recovery mechanisms for Duke Energy Kentucky and Duke Energy Ohio, Inc.

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 support the revenue requirement proposed by Duke Energy Kentucky. Toward that end, I support various adjustments to the projected data for the forecasted test period provided by Duke Energy Kentucky witness, Abby L. Motsinger and sponsor Filing Requirements (FR) 16(6)(b), 16(6)(c), 16(6)(f) and 16(7)(t). I also sponsor the following schedules: Schedule A in satisfaction of FR 16(8)(a) and Schedule B-1, in response to FR 16(8)(b); Schedules C-1 through C-2.1 in compliance with FR 16(8)(c); Schedules D-1, D-2.15, D-2.16, D-2.18, D-2.19, D-2.22, D-2.24 and D-2.26 in compliance with FR 16(8)(d); Schedules F-1 through F-7 in compliance with FR 16(8)(f); Schedules G-1 and H in response to FR 16(8)(g) and FR16((8)(h), respectively; and Workpapers WPB-1a, WPB-6c-f, WPC-2a-e, WPC-2.1a, WPD-2.15a-b, WPD-2.16a, WPD-2.18a, WPD-2.19a-f, WPD-2.22a, WPD-2.24a-b, WPD-2.26a-c, WPF-4a-b, WPF-5a-b.

II. TEST PERIOD AND RATE BASE

Q. WHAT IS THE TEST PERIOD IN THIS PROCEEDING?

A. The Company has elected to use a forecasted test period in this proceeding. The forecasted test period reflects the twelve months ending December 31, 2022, adjusted for known and measurable changes. The base period is twelve months ending August 31, 2021, consisting of six months of actual data, through February 2021, and the remaining six months of forecasted data.

Q. HOW WERE THE RATE BASE AND CAPITALIZATION DETERMINED IN THIS PROCEEDING?

A. The Company determined rate base and capitalization using a thirteen-month average for the forecasted test period ending December 31, 2022. The base period rate base and capitalization represent end-of-period balances.

Q. DID THE COMPANY FOLLOW THE COMMISSION'S GUIDELINES IN DEVELOPING THE BASE AND FORECASTED TEST PERIOD DATA?

A. Yes. Per the Commission's rules, 807 KAR 5:001, Section 16(7)(e)(2), "the forecast contains the same assumptions and methodologies as used in the forecast period for use by management." As described by Ms. Motsinger, the base and forecasted test periods were developed using the same methods applied in the Company's annual budgeting process. The first six months of the base period are actual results and are taken from the Company's books and records.

III. FILING REQUIREMENTS SPONSORED BY WITNESS

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)(c).

A. FR 16(6)(c) requires that capitalization and net investment rate base are based on a thirteen-month average for the forecasted test period, in this case, the twelve months ending December 31, 2022.

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

A. FR 16(6)(f) contains a reconciliation of the capital and rate base used to determine the revenue requirement in this case.

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

A. FR 16(7)(t) contains a list of all commercially available or in-house developed computer software, programs, and models used in the development of the schedules and workpapers associated with the filing of the utility's application.

Q. PLEASE DESCRIBE SCHEDULE A.

A. Schedule A is the overall financial summary for both the base period and the forecasted period at present rates. Based on the filing in this proceeding, as adjusted, the Company's natural gas operations are projected to earn a return on rate base of

4.620 percent for the forecasted test period, which is considerably less than the 7.060 percent return requested in this proceeding. In order to achieve the appropriate return on rate base, Duke Energy Kentucky's natural gas base revenues must increase $15,228,161, as shown in Schedule A.

Q. WHY IS THE COMPANY USING RATE BASE AS THE BASIS FOR COMPUTING ITS REVENUE REQUIREMENT?

A. The Company believes that using rate base to calculate the revenue requirement is the simplest and most transparent method. The Company's current natural gas base rates were established using rate base as part of the Company's last natural gas base rate proceeding in Case No. 2018-00261. The Commission also authorized Duke Energy Kentucky to use the rate base approach to determine its electric base rates in the Company's most recent electric base rate case.

Q. PLEASE DESCRIBE SCHEDULE B-1.

A. Schedule B-1 is the jurisdictional rate base summary for both the base and forecasted periods and is supported by various schedules in Section B of the Company's filing. The plant in service, and reserve for accumulated depreciation and amortization for the base and forecasted periods were summarized from Schedules B-2, B-3, and B-3.2 as supported by Company witnesses Mr. David Raiford and Ms. Motsinger. The working capital component was summarized from Schedule B-5, as supported by Ms. Motsinger, and other items of rate base were obtained from Schedule B-6, as supported by Mr. John R. Panizza. The jurisdictional natural gas rate base for the forecast period as contained in Schedule B-1 is $468,321,206.

Q. PLEASE DESCRIBE SCHEDULE C-1.

A. Schedule C-1 is a jurisdictional operating income summary for the forecasted period ended December 31, 2022. This schedule includes the operating income summary at both current and proposed rates. It assumes that the Commission allows the total amount of the requested natural gas base revenue increase of $15,228,161. The adjusted operating results at current rates were summarized from Schedule C-2 and the proposed increase was obtained from Schedule M. The revenue at proposed rates was developed by adding the revenue increase to the operating revenues at current rates. The related expenses and taxes on the proposed increase were added to the current adjusted operating results to determine the jurisdictional *pro forma* amounts and the corresponding rate of return. The rate base as shown on this schedule is calculated on Schedule B-1.

Q. PLEASE DESCRIBE SCHEDULE C-2.

A. Schedule C-2 is a jurisdictional operating income statement to be used for ratemaking purposes. In order to develop the forecasted test period that is appropriate for ratemaking, a two-step process was required. First, as required by 807 KAR 5:001, Section 16(6)(a), it was necessary to show the adjustments necessary to transform the financial data for the base period into the forecasted period. Second, it was necessary to adjust the forecasted period data to reflect any adjustments required to ensure that the revenues and expenses to be recovered in rates are representative of the expected costs to serve Duke Energy Kentucky natural gas customers on an ongoing basis.

Schedule C-2 starts with the unadjusted base period and shows the adjustments required to extend the Company's income statement from the base period to the forecasted period. The next column on the schedule summarizes the adjustments to the unadjusted forecasted test period. These adjustments are described below. Generally, they relate to costs that were not reflected in the Company's forecasted data or were reflected in the forecasted data but not allocable to Duke Energy Kentucky's natural gas customers or were made to reflect traditional ratemaking methodology. The unadjusted operating results are summarized from Schedule C-2.1. The adjusted amounts include the effects of the adjustments summarized on Schedule D-1.

Q. PLEASE DESCRIBE SCHEDULE C-2.1.

A. Schedule C-2.1 sets forth the detail of total Company operating results for both the base and forecasted periods. The operating results as shown in this Schedule C-2.1 are listed by account and are summarized on Schedule C-2.

Q. PLEASE DESCRIBE SCHEDULE D-1.

A. Schedule D-1 is a summary of the detailed adjustments to test period operating revenues and operating expenses as set forth in Schedules D-2.1 through D-2.26.

Q. WHY ARE ADJUSTMENTS TO THE BASE AND FORECASTED PERIOD INFORMATION NECESSARY?

A. The adjustments shown in Schedules D-2.1 through D-2.14 reflect the normal budgetary changes that are expected to occur from the base period through the forecasted period. Schedules D-2.1 through D-2.14, are sponsored by Ms. Motsinger. The remaining adjustments, shown in Schedules D-2.15 through D-2.26, present adjustments to the forecasted period data needed to ensure that the correct level of revenue and expense is included in rates at the proper ongoing level. Some costs, although reflected in the normal forecasting process, are not recoverable from Duke Energy Kentucky's natural gas customers. Other adjustments were made to reflect traditional ratemaking methodology (*e.g.*, annualizing depreciation expense). The reflection of a proper cost level is necessary in order to ensure that customers are not paying for more than the cost of providing service and to give the Company a reasonable opportunity to earn its authorized return. Ignoring appropriate adjustments to the test period used for setting rates puts customers at risk for overpaying for service and puts the Company at risk for potentially under-recovering its ongoing costs. Schedule D-2.23 is sponsored by Mr. Raiford. Schedule D-2.25 is sponsored by Ms. Motsinger. Schedules D-2.15, D-2.16, D-2.18, D-2.19, D-2.22, D-2.24 and D-2.26 are discussed in my testimony below.

Q. HOW ARE THE TAX EFFECTS OF THESE ADJUSTMENTS SHOWN ON YOUR SCHEDULES?

A. All applicable adjustments to taxes, including taxes other than income taxes and state and federal income taxes resulting from the adjustments, described below, are shown for each individual adjustment on Schedule D-1.

Q. PLEASE DESCRIBE SCHEDULE D-2.15.

A. Schedule D-2.15 is an adjustment for uncollectible expenses. The Company sells all of its accounts receivable to an affiliate, Cinergy Receivables, L.L.C. (Cinergy Receivables) at a discount. The discount is based on a formula that compensates the purchasing company for the time value of money and reflects Duke Energy Kentucky's net bad debt expense.

Since the short-term debt component of the Company's weighted-average cost of capital calculation in Schedule J-1 includes the average balance of receivables at the interest rate being paid to Cinergy Receivables, the adjustment shown in Schedule D-2.15 ensures that there is no double recovery of the time value of money in the uncollectible expense. Consequently, the time value of money component of the discount being charged to Uncollectible Expense (Account 426) is eliminated from the forecasted test period expenses. The adjustment reduces test period expenses by $1,227,152.

Q. PLEASE DESCRIBE SCHEDULE D-2.16.

A. The adjustment in Schedule D-2.16 is to amortize the projected cost of presenting the instant case. Duke Energy Kentucky proposes to amortize these costs over five years, which increases test period operating expenses by $70,692.

Q. PLEASE DESCRIBE SCHEDULE D-2.18.

A. Interest synchronization is used to ensure that the revenue requirement reflects the appropriate income tax effects for interest expense determined in the weighted-average cost of capital. Schedule D-2.18 presents the calculation of the state and federal income taxes on the interest cost included in the cost of capital. The adjustment is calculated by first determining the debt portion of total natural gas rate base. The natural gas rate base is multiplied by the long-term and short-term debt percentage of total capital structure.

The result is then multiplied by the average cost of long-term and short-term debt. The sum of these results represents the annualized natural gas interest cost deductible for income tax purposes. From this annualized total, we subtract the forecasted test period natural gas book interest to determine the natural gas interest expense adjustment for income tax purposes. The effect of this adjustment on natural gas operations is to decrease test period federal income taxes by $61,751 and to decrease test period state income taxes by $15,374.

Q. PLEASE DESCRIBE SCHEDULE D-2.19.

A. Schedule D-2.19 reflects the elimination of revenues and expenses applicable to natural gas operations devoted to other than Duke Energy Kentucky customers associated with the propane storage cavern and related mixing facilities, odorization stations, and various feeder lines.

The effect of this elimination is to reduce other revenue by $1,451,196; O&M expenses for production by $45,985 and distribution by $53,783; property tax expense by $241,662; state deferred taxes by $84,184; and federal deferred taxes by $338,023. Depreciation expense applicable to these facilities is not included in the annualized depreciation expense calculated on Schedule B-3.2, as a result of the plant investment being excluded on Schedule B-2.1, and therefore has been eliminated from the test period via Schedule D-2.23.

These adjustments also impact the accumulated deferred income tax (ADIT) and excess accumulated deferred income tax (EDIT) balances as shown on Schedule B-6. The effect of these adjustments on the test period is shown on workpaper WPB-6d and has the effect of reducing ADIT balances by $3,704,425 and EDIT balances by $1,686,110.

Q. PLEASE DESCRIBE SCHEDULE D-2.22.

A. Schedule D-2.22 is an adjustment to eliminate miscellaneous expenses such as community relations, advertising, donations, employee recognition, governmental affairs, club dues and miscellaneous events expenses from the forecasted test period. These adjustments were made in order to comply with the Commission's orders in prior rate proceedings. The effect of the adjustment on natural gas operations is a decrease in test period operating expenses of $246,856.

Q. PLEASE DESCRIBE SCHEDULE D-2.24.

A. Schedule D-2.24 is an adjustment to eliminate unbilled revenue and natural gas costs from the forecasted test period. The adjustment increases revenue in the forecasted test period by $1,049,665 and increases natural gas costs by $716,846.

Q. PLEASE DESCRIBE SCHEDULE D-2.26.

A. Schedule D-2.26 is an adjustment to eliminate incentive compensation from the forecasted test period to eliminate a portion of incentive compensation expense included in the test period related to the achievement of financial goals. The adjustment utilizes a methodology similar to the one adopted by the Commission in Case No. 2017-00321 and applied in subsequent proceedings, and removes incentive compensation included in the forecasted test period tied to the achievement of financial goals of the Company and stock-based compensation. The adjustment decreases incentive compensation expense in the forecasted test period by $583,357.

Q. PLEASE DESCRIBE SCHEDULE F-1.

A. Schedule F-1 sets forth the detail, by account, of Social and Service Club Dues for both the base and unadjusted forecasted test periods. All amounts are either charged below the line or have been removed from operating expenses on Schedule D-2.22 and, thus, not included in the forecasted test period revenue requirement.

Q. PLEASE DESCRIBE SCHEDULE F-2.1.

A. Schedule F-2.1 sets forth the detail, by account, of Charitable Contributions for both the base period and unadjusted forecasted test periods. All amounts are charged below the line and, thus, not included in the forecasted test period revenue requirement.

Q. PLEASE DESCRIBE SCHEDULE F-2.2.

A. Schedule F-2.2 indicates that the Initiation Fees and Country Club expenses for the base and forecasted test periods are included on Schedule F-1.

Q. PLEASE DESCRIBE SCHEDULE F-2.3.

A. Schedule F-2.3 sets forth the detail, by account of Employee Party, Outing, & Gift Expense for both the base and forecasted test periods.

Q. PLEASE DESCRIBE SCHEDULE F-3.

A. Schedule F-3 sets forth the detail, by account, of Customer Service and Informational Expense, Sales Expense and General Advertising Expense for both the base and unadjusted forecasted test periods. Advertising costs included in Account 930150 have been removed from operating expenses on Schedule D-2.22 and, thus, not included in the forecasted test period revenue requirement.

Q. PLEASE DESCRIBE SCHEDULE F-4.

A. Schedule F-4 sets forth additional details supporting advertising costs for both the base and unadjusted forecasted test periods. As noted above, these costs are not included in the forecasted test period revenue requirement.

Q. PLEASE DESCRIBE SCHEDULE F-5.

A. Schedule F-5 sets forth the detail of Professional Services Expenses for both the base and forecasted test periods.

Q. PLEASE DESCRIBE SCHEDULE F-6.

A. Schedule F-6, entitled "Rate Case Expense," indicates the estimated expense of presenting this case. The top half of this schedule details the estimated expense of this proceeding. Also included is a comparison to the rate case expense in the Company's last two rate case proceedings. The bottom half of this schedule shows the amortization over a five-year period. This amount is included in expense through the adjustment contained in Schedule D-2.16.

Q. PLEASE DESCRIBE SCHEDULE F-7.

A. Schedule F-7 sets forth Civic, Political and Related Expense for both the base and unadjusted forecasted test periods. All amounts are charged below the line and, thus, not included in the forecasted test period revenue requirement.

Q. PLEASE DESCRIBE SCHEDULE G-1.

A. Schedule G-1 contains a summary of all payroll costs and related benefits and taxes included in natural gas O&M expense for both the base and forecasted test periods.

Q. PLEASE DESCRIBE SCHEDULE H.

A. Schedule H, entitled "Computation of Gross Revenue Conversion Factor," (GRCF) sets forth the calculation of the GRCF. This is the factor, or multiplier, used to gross-up the operating income deficiency to a revenue deficiency amount. It includes the Kentucky Public Service Commission assessment, and state and federal income taxes. The GRCF is included on Schedule A and is used to compute the calculated revenue deficiency.

Q. DO YOU SPONSOR ANY OTHER WORKPAPERS AS PART OF THIS RATE CASE PROCEEDING?

A. Yes, I sponsor workpapers WPB-1a, WPC-2a-e, WPC-2.1a, WPD-2.15a-b, WPD-2.16a, WPD-2.18a, WPD-2.19a-f, WPD-2.22a, WPD-2.24a-b, WPD-2.26a-c, WPF-4a-b, and WPF-5a-b which support schedules B-1, C schedules, D-2.15, D-2.16, D-2.18, D-2.19, D-2.22, D-2.23, D-2.24, D-2.26, F-4, and F5 respectively. I also co-sponsor workpapers WPB-6c, WPB-6d, WPB-6e, and WPB-6f with Company witness John R. Panizza ultimately supporting Schedule B-6, sponsored by Mr. Panizza.

Q. CAN YOU DESCRIBE THE ADJUSTMENTS BEING PROPOSED TO ADIT AND EDIT BALANCES IN WORKPAPERS WPB-6C-F?

A. Yes. Workpapers WPB-6c and WPB-6d adjust ADIT and EDIT balances for the base period and test period respectively to eliminate the ADIT and EDIT balances applicable to natural gas operations devoted to other than Duke Energy Kentucky customers associated with the propane storage cavern and related mixing facilities, odorization stations, and various feeder lines.

Workpapers WPB-6e and WPB-6f remove ADIT balances associated with assets and liabilities not included in rate base for the base period and test period respectively. Because the net deferred taxes associated with assets and liabilities not included in rate base is a deferred tax asset, the adjustment to the test period has the effect of increasing ADIT and ultimately reducing rate base by $428,533.

IV. CONCLUSION

Q. WERE FR 16(6)(b), FR 16(6)(c), FR 16(6)(f), AND FR 16(7)(t), SCHEDULES A, B-1, C-1 THROUGH C-2.1, D-1, D-2.15, D-2.16, D-2.18, D-2.19, D-2.22, D-2.24 AND D-2.26, F-1 THROUGH F-7, G-1, H AND WORKPAPERS; WPB-1A, WPB-6C-F, WPC-2A-E, WPC-2.1A, WPD-2.15A-B, WPD-2.16A, WPD-2.18A, WPD-2.19A-F, WPD-2.22A, WPD-2.24A-B, WPD-2.26A-C, WPF-4A-B, WPF-5A-B PREPARED BY YOU OR 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 Natural Gas Rates; (2) Approval of New Tariffs; and (3) All Other Required Approvals, Waivers, and Relief.	)))))	Case No. 2021-00190

DIRECT TESTIMONY OF

DYLAN W. D'ASCENDIS

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

June 1, 2021

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LIST OF ATTACHMENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dylan W. D'Ascendis. My business address is 3000 Atrium Way, Suite 241, Mount Laurel, NJ 08054.

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

A. I am a Director at ScottMadden, Inc.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I have offered expert testimony on behalf of investor-owned utilities before over 25 state regulatory commissions in the United States, the Federal Energy Regulatory Commission, the Alberta Utility Commission, an American Arbitration Association panel, and the Superior Court of Rhode Island on issues including, but not limited to, common equity cost rate, rate of return, valuation, capital structure, class cost of service, and rate design.

On behalf of the American Gas Association (AGA), I calculate the AGA Gas Index, which serves as the benchmark against which the performance of the American Gas Index Fund (AGIF) is measured on a monthly basis. The AGA Gas Index and AGIF are a market capitalization weighted index and mutual fund, respectively, comprised of the common stocks of the publicly traded corporate members of the AGA.

I am a member of the Society of Utility and Regulatory Financial Analysts (SURFA). In 2011, I was awarded the professional designation "Certified Rate of

Return Analyst" by SURFA, which is based on education, experience, and the successful completion of a comprehensive written examination.

I am also a member of the National Association of Certified Valuation Analysts (NACVA) and was awarded the professional designation "Certified Valuation Analyst" by the NACVA in 2015.

I am a graduate of the University of Pennsylvania, where I received a Bachelor of Arts degree in Economic History. I have also received a Master of Business Administration with high honors and concentrations in Finance and International Business from Rutgers University.

The details of my educational background and expert witness appearances are shown in Appendix A.

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

A. The purpose of my testimony is to present evidence and provide a recommendation regarding Duke Energy Kentucky, Inc.'s (Duke Energy Kentucky or the Company) return on common equity (ROE) for its natural gas distribution operations.

Q. HAVE YOU PREPARED ATTACHMENTS IN SUPPORT OF YOUR RECOMMENDATION?

A. Yes. I have prepared Attachments DWD-1 through DWD-9, which were prepared by me or under my direction.

Q. WHAT IS YOUR RECOMMENDED COMMON EQUITY COST RATE?

A. I recommend that the Commission authorize Duke Energy Kentucky the opportunity to earn an ROE of 10.30% on its natural gas rate base. The ratemaking capital structure and cost of debt is sponsored by Company witness Mr. Chris Bauer. The overall rate of return is summarized on page 1 of Attachment DWD-1 and in Table 1 below:

Table 1: Summary of Recommended Weighted Average Cost of Capital

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	46.721%	3.843%	1.795%
Short-Term Debt	2.584%	1.667%	0.043%
Common Equity	50.695%	10.30%	5.222%
Total	100.00%		7.060%

Q. PLEASE SUMMARIZE YOUR RECOMMENDED COMMON EQUITY COST RATE.

A. My recommended common equity cost rate of 10.30% is summarized on page 2 of Attachment DWD-1. I have assessed the market-based common equity cost rates of companies of relatively similar, but not necessarily identical, risk to Duke Energy Kentucky. Using companies of relatively comparable risk as proxies is consistent with the principles of fair rate of return established in the *Hope*[1] and *Bluefield*[2] decisions. No proxy group can be identical in risk to any single company. Consequently, there must be an evaluation of relative risk between the company and the proxy group to determine if it is appropriate to adjust the proxy group's indicated rate of return.

My recommendation results from applying several cost of common equity models, specifically the Discounted Cash Flow (DCF) model, the Risk Premium

[1] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
[2] *Bluefield Water Works Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679 (1922).

Model (RPM), and the Capital Asset Pricing Model (CAPM), to the market data of a proxy group of seven natural gas distribution utilities (Utility Proxy Group) whose selection criteria will be discussed below. In addition, I applied the DCF model, RPM, and CAPM to a proxy group of 48 domestic, non-price regulated companies comparable in total risk to the Utility Proxy Group (Non-Price Regulated Proxy Group). The results derived from each are as follows:

Table 2: Summary of Common Equity Cost Rates

Discounted Cash Flow Model	9.57%
Risk Premium Model	10.65%
Capital Asset Pricing Model	11.62%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	12.27%
Indicated Range	9.57% - 12.27%
Size Adjustment	0.15%
Credit Risk Adjustment	0.14%
Flotation Cost Adjustment	0.12%
Recommended Range	9.98% - 12.68%
Recommended Cost of Common Equity	10.30%

The indicated range of common equity cost rates applicable to the Utility Proxy Group is between 9.57% and 12.27% before any Company-specific adjustments. I then adjusted the indicated range by 0.15% and 0.14% to reflect the Company's smaller relative size and greater credit risk, as compared to the Utility Proxy Group companies, and by 0.12% for flotation costs.[3] These adjustments

[3] *See* Section VI for a detailed discussion of my cost of common equity adjustments.

resulted in a Company-specific indicated range of common equity cost rates between 9.98 % and 12.68%.

The wide range of model results may reflect increased uncertainty related to the COVID-19 pandemic and unknown timeframe for when economic conditions will normalize as vaccinations ramp up and the public health crises subsides. Because of this uncertainty, I recommend a ROE for the Company toward the lower end of my Company-specific range, specifically 10.30%.

Q. HOW IS THE REMAINDER OF YOUR DIRECT TESTIMONY ORGANIZED?

A. The remainder of my Direct Testimony is organized as follows:

- Section II – Provides a summary of financial theory and regulatory principles pertinent to the development of the cost of common equity;
- Section III – Explains my selection of the Utility Proxy Group used to develop my Cost of Common Equity analytical results;
- Section IV – Describes the analyses on which my Cost of Common Equity recommendation is based;
- Section V – Summarizes my common equity cost rate before adjustments to reflect Company-specific factors;
- Section VI – Explains my adjustments to my common equity cost rate to reflect Company-specific factors;
- Section VII – Presents my conclusions.

II. GENERAL PRINCIPLES

Q. WHAT GENERAL PRINCIPLES HAVE YOU CONSIDERED IN ARRIVING AT YOUR RECOMMENDED COMMON EQUITY COST RATE OF 10.30%?

A. In unregulated industries, marketplace competition is the principal determinant of the price of products or services. For regulated public utilities, regulation must act as a substitute for marketplace competition. Assuring that the utility can fulfill its obligations to the public, while providing safe and reliable service at all times, requires a level of earnings sufficient to maintain the integrity of presently invested capital. Sufficient earnings also permit the attraction of needed new capital at a reasonable cost, for which the utility must compete with other forms of comparable risk, consistent with the fair rate of return standards established by the U.S. Supreme Court in the previously cited *Hope* and *Bluefield* cases.

The U.S. Supreme Court affirmed the fair rate of return standards in *Hope*, when it stated:

> The rate-making process under the Act, *i.e.,* the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. at page 590, 62 S.Ct. at page 745. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. Cf. Chicago & Grand Trunk R. Co. v. Wellman, 143 U.S. 339, 345, 346 12 S.Ct. 400,402. By that standard the 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.[4]

Consistent with the findings in *Hope*, the Commission's decision in this proceeding should provide the Company with the opportunity to earn a return that is: (1) adequate to attract capital at reasonable cost and terms; (2) sufficient to ensure their financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks.

Also, the required return for a regulated public utility is established on a stand-alone basis, *i.e.*, for the utility operating company at issue in a rate case. When funding is provided by a parent entity, the allowed return still must be sufficient to provide an incentive to allocate equity capital to the subsidiary or business unit rather than other internal or external investment opportunities. That is, the regulated subsidiary must compete for capital with all the parent company's affiliates, and with other, similarly situated companies. In that regard, investors value corporate entities on a sum-of-the-parts basis and expect each division within the parent company to provide an appropriate risk-adjusted return.

It therefore is important that the authorized ROE reflects the risks and prospects of the utility's operations and supports the utility's financial integrity from a stand-alone perspective as measured by their combined business and financial risks. Consequently, the ROE authorized in this proceeding should be sufficient to support the business risk and financial risk of the Company's Kentucky utility operations on a stand-alone basis.

[4] *Hope*, 320 U.S. 591 (1944), at 603.

Q. WITHIN THAT BROAD FRAMEWORK, HOW IS THE COST OF CAPITAL ESTIMATED IN REGULATORY PROCEEDINGS?

A. Regulated utilities primarily use common stock and long-term debt to finance their permanent property, plant, and equipment (*i.e.*, rate base). The fair rate of return for a regulated utility is based on its weighted average cost of capital, in which, as noted earlier, the costs of the individual sources of capital are weighted by their respective book values.

The cost of capital is the return investors require to make an investment in a firm. Investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm.

The cost of capital (that is, the combination of the costs of debt and equity) is based on the economic principle of "opportunity costs." Investing in any asset (whether debt or equity securities) represents a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable risk investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk.

Whereas the cost of debt is contractually defined and can be directly observed as the interest rate or yield on debt securities, the cost of common equity must be estimated based on market data and various financial models. Because the cost of common equity is premised on opportunity costs, the models used to determine it are typically applied to a group of "comparable" or "proxy" companies.

In the end, the estimated cost of capital should reflect the return that investors require in light of the subject company's business and financial risks, and the returns available on comparable investments.

Q. IS THE AUTHORIZED RETURN SET IN REGULATORY PROCEEDINGS GUARANTEED?

A. No, it is not. Consistent with the *Hope* and *Bluefield* standards, the rate-setting process should provide the utility a reasonable opportunity to recover its return of, and return on, its prudently incurred investments, but it does not guarantee that return. While a utility may have control over some factors that affect the ability to earn its authorized return (*e.g.*, management performance, operating and maintenance expenses, *etc.*), there are several factors beyond a utility's control that affect its ability to earn its authorized return. Those may include factors such as weather, the economy, and the prevalence and magnitude of regulatory lag.

A. Business Risk

Q. PLEASE DEFINE BUSINESS RISK AND EXPLAIN WHY IT IS IMPORTANT FOR DETERMINING A FAIR RATE OF RETURN.

A. The investor-required return on common equity reflects investors' assessment of the total investment risk of the subject company. Total investment risk is often discussed in the context of business and financial risk.

Business risk reflects the uncertainty associated with owning a company's common stock without the company's use of debt and/or preferred stock financing.

One way of considering the distinction between business and financial risk is to view the former as the uncertainty of the expected earned return on common equity, assuming the firm is financed with no debt.

Examples of business risks <u>generally</u> faced by utilities include, but are not limited to, the regulatory environment, mandatory environmental compliance requirements, customer mix and concentration of customers, service territory economic growth, market demand, risks and uncertainties of supply, operations, capital intensity, size, the degree of operating leverage, and the like, all of which have a direct bearing on earnings. Although analysts, including rating agencies, may categorize business risks individually, as a practical matter, such risks are interrelated and not wholly distinct from one another. For determining an appropriate return on common equity, the relevant issue is where investors see the subject company as falling within a spectrum of risk. To the extent investors view a company as being exposed to high risk, the required return will increase, and vice versa.

For regulated utilities, business risks are both long-term and near-term in nature. Whereas near-term business risks are reflected in year-to-year variability in earnings and cash flow brought about by economic or regulatory factors, long-term business risks reflect the prospect of an impaired ability of investors to obtain both a fair rate of return on, and return of, their capital. Moreover, because utilities accept the obligation to provide safe, adequate and reliable service at all times (in exchange for a reasonable opportunity to earn a fair return on their investment), they generally do not have the option to delay, defer, or reject capital investments.

Because those investments are capital-intensive, utilities generally do not have the option to avoid raising external funds during periods of capital market distress, if necessary.

Because utilities invest in long-lived assets, long-term business risks are of paramount concern to equity investors. That is, the risk of not recovering the return on their investment extends far into the future. The timing and nature of events that may lead to losses, however, also are uncertain and, consequently, those risks and their implications for the required return on equity tend to be difficult to quantify. Regulatory commissions (like investors who commit their capital) must review a variety of quantitative and qualitative data and apply their reasoned judgment to determine how long-term risks weigh in their assessment of the market-required return on common equity.

B. <u>Financial Risk</u>

Q. PLEASE DEFINE FINANCIAL RISK AND EXPLAIN WHY IT IS IMPORTANT IN DETERMINING A FAIR RATE OF RETURN.

A. Financial risk is the additional risk created by the introduction of debt and preferred stock into the capital structure. The higher the proportion of debt and preferred stock in the capital structure, the higher the financial risk to common equity owners (*i.e.*, failure to receive dividends due to default or other covenants). Therefore, consistent with the basic financial principle of risk and return, common equity investors demand higher returns as compensation for bearing higher financial risk.

Q. CAN BOND AND CREDIT RATINGS BE A PROXY FOR A FIRM'S COMBINED BUSINESS AND FINANCIAL RISKS TO EQUITY OWNERS (*I.E.*, INVESTMENT RISK)?

A. Yes, similar bond ratings/issuer credit ratings reflect, and are representative of, similar combined business and financial risks (*i.e.*, total risk) faced by bond investors.[5] Although specific business or financial risks may differ between companies, the same bond/credit rating indicates that the combined risks are roughly similar from a debtholder perspective. The caveat is that these debtholder risk measures do not translate directly to risks for common equity.

Q. DO RATING AGENCIES ACCOUNT FOR COMPANY SIZE IN THEIR BOND RATINGS?

A. No. Neither Standard & Poor's (S&P) nor Moody's have minimum company size requirements for any given rating level. This means, all else equal, a relative size analysis must be conducted for equity investments in companies with similar bond ratings.

III. DUKE ENERGY KENTUCKY'S OPERATIONS AND THE UTILITY PROXY GROUP

Q. ARE YOU FAMILIAR WITH DUKE ENERGY KENTUCKY'S OPERATIONS?

A. Yes. Duke Energy Kentucky, a subsidiary of Duke Energy Corporation (DUK), has a service territory located in northern Kentucky adjacent to the city of Cincinnati

[5] Risk distinctions within S&P's bond rating categories are recognized by a plus or minus, *e.g.*, within the A category, an S&P rating can by at A+, A, or A-. Similarly, risk distinction for Moody's ratings are distinguished by numerical rating gradations, *e.g.*, within the A category, a Moody's rating can be A1, A2 and A3.

and is comprised of numerous cities, towns, and communities. Duke Energy Kentucky purchases, sells, stores, and transports natural gas in Boone, Bracken, Campbell, Gallatin, Grant, Kenton, and Pendleton Counties. Duke Energy Kentucky also generates electricity, which it distributes and sells in Boone, Campbell, Grant, Kenton, and Pendleton Counties. The Company's Kentucky natural gas operations services approximately 102,422 customers.[6] Duke Energy Kentucky currently has senior unsecured ratings of Baa1 (outlook: Stable) and BBB+ (outlook: Stable) from Moody's Investor Service and Standard & Poor's Rating Services, respectively.[7]

Q. PLEASE EXPLAIN HOW YOU CHOSE THE COMPANIES IN THE UTILITY PROXY GROUP.

A. The companies selected for the Utility Proxy Group met the following criteria:

(i) They were included in the Natural Gas Utility Group of *Value Line's Standard Edition* (*Value Line*) (February 26, 2021);

(ii) They have 60% or greater of fiscal year 2020 total operating income derived from, and 60% or greater of fiscal year 2020 total assets attributable to, regulated gas distribution operations;

(iii) At the time of preparation of this testimony, they had not publicly announced that they were involved in any major merger or acquisition activity (*i.e.*, one publicly-traded utility merging with or acquiring another);

(iv) They have not cut or omitted their common dividends during the five years ended 2020 or through the time of preparation of this testimony;

(v) They have *Value Line* and Bloomberg Professional Services (Bloomberg) adjusted betas;

[6] Company provided.

[7] Source: S&P Global Market Intelligence.

(vi) They have positive *Value Line* five-year dividends per share (DPS) growth rate projections; and

(vii) They have *Value Line*, Zacks, Yahoo! Finance, or Bloomberg consensus five-year earnings per share (EPS) growth rate projections.

The following seven companies met these criteria: Atmos Energy Corporation, New Jersey Resources Corp., Northwest Natural Holding Company, One Gas, Inc., South Jersey Industries, Inc., Southwest Gas Holdings, Inc., and Spire, Inc.

Q. WHY IS IT NECESSARY TO DEVELOP A PROXY GROUP WHEN ESTIMATING THE ROE FOR THE COMPANY?

A. Because the Company is not publicly traded and does not have publicly traded equity securities, it is necessary to develop groups of publicly traded, comparable companies to serve as "proxies" for the Company. In addition to the analytical necessity of doing so, the use of proxy companies is consistent with the *Hope* and *Bluefield* comparable risk standards, as discussed above. I have selected two proxy groups that, in my view, are fundamentally risk-comparable to the Company: a Utility Proxy Group and a Non-Price Regulated Proxy Group, which is comparable in total risk to the Utility Proxy Group.[8]

Even when proxy groups are carefully selected, it is common for analytical results to vary from company to company. Despite the care taken to ensure comparability, because no two companies are identical, market expectations regarding future risks and prospects will vary within the proxy group. It therefore is common for analytical results to reflect a seemingly wide range, even for a group

[8] The development of the Non-Price Regulated Proxy Group is explained in more detail in Section IV.

of similarly situated companies. At issue is how to estimate the ROE from within that range. That determination will be best informed by employing a variety of sound analyses that necessarily must consider the sort of quantitative and qualitative information discussed throughout my Direct Testimony. Additionally, a relative risk analysis between the Company and the Utility Proxy Group must be made to determine whether or not explicit Company-specific adjustments need to be made to the Utility Proxy Group indicated results.

IV. COMMON EQUITY COST RATE MODELS

Q. IS IT IMPORTANT THAT COST OF COMMON EQUITY MODELS BE MARKET BASED?

A. Yes. A public utility must compete for equity in capital markets along with all other companies of comparable risk, which includes non-utilities. The cost of common equity is thus determined based on equity market expectations for the returns of those comparable risk companies. If an individual investor is choosing to invest their capital among companies of comparable risk, they will choose a company providing a higher return over a company providing a lower return.

Q. ARE YOUR COST OF COMMON EQUITY MODELS MARKET BASED?

A. Yes. The DCF model uses market prices in developing the model's dividend yield component. The RPM uses bond ratings and expected bond yields that reflect the market's assessment of bond/credit risk. In addition, beta coefficients (β), which reflect the market/systematic risk component of equity risk premium, are derived from regression analyses of market prices. The Predictive Risk Premium Model (PRPM) uses monthly market returns in addition to expectations of the risk-free rate. The CAPM is market based for many of the same reasons that the RPM is market based (*i.e.*, the use of expected bond yields and betas). Selection criteria for comparable risk non-price regulated companies are based on regression analyses of market prices and reflect the market's assessment of total risk.

Q. WHAT ANALYTICAL APPROACHES DID YOU USE TO DETERMINE THE COMPANY'S ROE?

A. As discussed earlier, I have relied on the DCF model, the RPM, and the CAPM, which I apply to the Utility Proxy Group described above. I also applied these same models to a Non-Price Regulated Proxy Group described later in this section.

I rely on these models because reasonable investors use a variety of tools and do not rely exclusively on a single source of information or single model. Moreover, the models on which I rely focus on different aspects of return requirements, and provide different insights to investors' views of risk and return. The DCF model, for example, estimates the investor-required return assuming a constant expected dividend yield and growth rate in perpetuity, while Risk Premium-based methods (*i.e.*, the RPM and CAPM approaches) provide the ability to reflect investors' views of risk, future market returns, and the relationship between interest rates and the cost of common equity. Just as the use of market data for the Utility Proxy Group adds the reliability necessary to inform expert judgment in arriving at a recommended common equity cost rate, the use of multiple generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate.

A. Discounted Cash Flow Model

Q. WHAT IS THE THEORETICAL BASIS OF THE DCF MODEL?

A. The theory underlying the DCF model is that the present value of an expected future stream of net cash flows during the investment holding period can be determined by discounting those cash flows at the cost of capital, or the investors' capitalization rate. DCF theory indicates that an investor buys a stock for an expected total return rate, which is derived from the cash flows received from dividends and market price appreciation. Mathematically, the dividend yield on market price plus a growth rate equals the capitalization rate; *i.e.*, the total common equity return rate expected by investors as shown below:

$$K_e = (D_0\,(1+g))/P + g$$

where:

K_e = the required Return on Common Equity;
D_0 = the annualized Dividend Per Share;
P = the current stock price; and
g = the growth rate.

Q. WHICH VERSION OF THE DCF MODEL DID YOU USE?

A. I used the single-stage constant growth DCF model in my analyses.

Q. PLEASE DESCRIBE THE DIVIDEND YIELD YOU USED IN APPLYING THE CONSTANT GROWTH DCF MODEL.

A. The unadjusted dividend yields are based on the proxy companies' dividends as of March 31, 2021, divided by the average closing market price for the 60 trading days ended March 31, 2021.[9]

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[9] *See*, column 1, page 1 of Attachment DWD-2.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE DIVIDEND YIELD.

A. Because dividends are paid periodically (*e.g.* quarterly), as opposed to continuously (daily), an adjustment must be made to the dividend yield. This is often referred to as the discrete, or the Gordon Periodic, version of the DCF model.

DCF theory calls for using the full growth rate, or D_1, in calculating the model's dividend yield component. Since the companies in the Utility Proxy Group increase their quarterly dividends at various times during the year, a reasonable assumption is to reflect one-half the annual dividend growth rate in the dividend yield component, or $D_{1/2}$. Because the dividend should be representative of the next 12-month period, this adjustment is a conservative approach that does not overstate the dividend yield. Therefore, the actual average dividend yields in Column 1, page 1 of Attachment DWD-2 have been adjusted upward to reflect one-half the average projected growth rate shown in Column 6.

Q. PLEASE EXPLAIN THE BASIS FOR THE GROWTH RATES YOU APPLY TO THE UTILITY PROXY GROUP IN YOUR CONSTANT GROWTH DCF MODEL.

A. Investors are likely to rely on widely available financial information services, such as *Value Line*, Zacks, Yahoo! Finance, and Bloomberg. Investors realize that analysts have significant insight into the dynamics of the industries and individual companies they analyze, as well as companies' ability to effectively manage the effects of changing laws and regulations, and ever-changing economic and market conditions. For these reasons, I used analysts' five-year forecasts of EPS growth in my DCF analysis.

Over the long run, there can be no growth in DPS without growth in EPS. Security analysts' earnings expectations have a more significant influence on market prices than dividend expectations. Thus, using earnings growth rates in a DCF analysis provides a better match between investors' market price appreciation expectations and the growth rate component of the DCF.

Q. PLEASE SUMMARIZE THE CONSTANT GROWTH DCF MODEL RESULTS.

A. As shown on page 1 of Attachment DWD-2, for the Utility Proxy Group, the mean result of applying the single-stage DCF model is 9.78%, the median result is 9.35%, and the average of the two is 9.57%. In arriving at a conclusion for the constant growth DCF-indicated common equity cost rate for the Utility Proxy Group, I relied on an average of the mean and the median results of the DCF. This approach considers all the proxy utilities' results, while mitigating the high and low outliers of those individual results.

B. <u>The Risk Premium Model</u>

Q. PLEASE DESCRIBE THE THEORETICAL BASIS OF THE RPM.

A. The RPM is based on the fundamental financial principle of risk and return; namely, that investors require greater returns for bearing greater risk. The RPM recognizes that common equity capital has greater investment risk than debt capital, as common equity shareholders are behind debt holders in any claim on a company's assets and earnings. As a result, investors require higher returns from common stocks than from bonds to compensate them for bearing the additional risk.

While it is possible to directly observe bond returns and yields, investors' required common equity returns cannot be directly determined or observed. According to RPM theory, one can estimate a common equity risk premium over bonds (either historically or prospectively) and use that premium to derive a cost rate of common equity. The cost of common equity equals the expected cost rate for long-term debt capital, plus a risk premium over that cost rate, to compensate common shareholders for the added risk of being unsecured and last-in-line for any claim on the corporation's assets and earnings upon liquidation.

Q. PLEASE EXPLAIN HOW YOU DERIVED YOUR INDICATED COST OF COMMON EQUITY BASED ON THE RPM.

A. To derive my indicated cost of common equity under the RPM, I used two risk premium methods. The first method was the PRPM and the second method was a risk premium model using a total market approach. The PRPM estimates the risk-return relationship directly, while the total market approach indirectly derives a risk premium by using known metrics as a proxy for risk.

1. The Predictive Risk Premium Model

Q. PLEASE EXPLAIN THE PRPM.

A. The PRPM, published in the *Journal of Regulatory Economics,*[10] was developed from the work of Robert F. Engle, who shared the Nobel Prize in Economics in 2003 "for methods of analyzing economic time series with time-varying volatility (ARCH)".[11] Engle found that volatility changes over time and is related from one

[10] Autoregressive conditional heteroscedasticity. See "A New Approach for Estimating the Equity Risk Premium for Public Utilities", Pauline M. Ahern, Frank J. Hanley and Richard A. Michelfelder, Ph.D. The Journal of Regulatory Economics (December 2011), 40:261-278.

[11] www.nobelprize.org.

period to the next, especially in financial markets. Engle discovered that volatility of prices and returns cluster over time and is therefore highly predictable and can be used to predict future levels of risk and risk premiums.

The PRPM estimates the risk-return relationship directly, as the predicted equity risk premium is generated by predicting volatility or risk. The PRPM is not based on an estimate of investor behavior, but rather on an evaluation of the results of that behavior (*i.e.*, the variance of historical equity risk premiums).

The inputs to the model are the historical returns on the common shares of each Utility Proxy Group company minus the historical monthly yield on long-term U.S. Treasury securities through March 2021. Using a generalized form of ARCH, known as GARCH, I calculated each Utility Proxy Group company's projected equity risk premium using Eviews© statistical software. When the GARCH model is applied to the historical return data, it produces a predicted GARCH variance series[12] and a GARCH coefficient[13]. Multiplying the predicted monthly variance by the GARCH coefficient and then annualizing it[14] produces the predicted annual equity risk premium. I then added the forecasted 30-year U.S. Treasury bond yield of 2.73%[15] to each company's PRPM-derived equity risk premium to arrive at an indicated cost of common equity. The 30-year U.S. Treasury bond yield is a consensus forecast derived from Blue Chip Financial Forecasts (*Blue Chip).*[16] The mean PRPM indicated common equity cost rate for the Utility Proxy Group is

[12] Illustrated on Columns 1 and 2, page 2 of Attachment DWD-3.
[13] Illustrated on Column 4, page 2 of Attachment DWD-3.
[14] Annualized Return = (1 + Monthly Return) ^12 - 1
[15] *See* Column 6, page 2 of Attachment DWD-3.
[16] *Blue Chip Financial Forecasts*, December 1, 2020 at page 14 and April 1, 2021 at page 2.

11.31%, the median is 10.61%, and the average of the two is 10.96%. Consistent with my reliance on the average of the median and mean results of the DCF models, I relied on the average of the mean and median results of the Utility Proxy Group PRPM to calculate a cost of common equity rate of 10.96%.

Q. PLEASE DESCRIBE YOUR SELECTION OF A RISK-FREE RATE OF RETURN.

A. As shown in Attachments DWD-3 and DWD-4, the risk-free rate adopted for applications of the RPM and CAPM is 2.73%. This risk-free rate is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the third calendar quarter of 2022, and long-term projections for the years 2022 to 2026 and 2027 to 2031.

Q. WHY DO YOU USE THE PROJECTED 30-YEAR TREASURY YIELD IN YOUR ANALYSES?

A. The yield on long-term U.S. Treasury bonds is almost risk-free and its term is consistent with the long-term cost of capital to public utilities measured by the yields on Moody's A2-rated public utility bonds; the long-term investment horizon inherent in utilities' common stocks; and the long-term life of the jurisdictional rate base to which the allowed fair rate of return (*i.e.*, cost of capital) will be applied. In contrast, short-term U.S. Treasury yields are more volatile and largely a function of Federal Reserve monetary policy.

2. The Total Market Risk Premium Approach

Q. PLEASE EXPLAIN THE TOTAL MARKET APPROACH RPM.

A. The total market approach RPM adds a prospective public utility bond yield to an average of: (1) an equity risk premium that is derived from a beta-adjusted total market equity risk premium, (2) an equity risk premium based on the S&P Utilities Index, and (3) an equity risk premium based on authorized ROEs for gas distribution utilities.

Q. PLEASE EXPLAIN THE BASIS OF THE EXPECTED BOND YIELD OF 3.91% APPLICABLE TO THE UTILITY PROXY GROUP.

A. The first step in the total market approach RPM analysis is to determine the expected bond yield. Because both ratemaking and the cost of capital, including common equity cost rate, are prospective in nature, a prospective yield on similarly rated long-term debt is essential. I relied on a consensus forecast of about 50 economists of the expected yield on Aaa-rated corporate bonds for the six calendar quarters ending with the third calendar quarter of 2022, and *Blue Chip's* long-term projections for 2022 to 2026, and 2027 to 2031. As shown on line 1, page 3 of Attachment DWD-3, the average expected yield on Moody's Aaa-rated corporate bonds is 3.44%. To derive an expected yield on Moody's A2-rated public utility bonds, I made an upward adjustment of 0.42%, which represents a recent spread between Aaa-rated corporate bonds and A2-rated public utility bonds, in order to adjust the expected Aaa-rated corporate bond yield to an equivalent A2-rated public utility bond yield.[17] Adding that recent 0.42% spread to the expected Aaa-rated

[17] As shown on line 2 and explained in note 2, page 3 of Attachment DWD-3.

corporate bond yield of 3.44% results in an expected A2-rated public utility bond yield of 3.86%.

I then reviewed the average credit rating for the Utility Proxy Group from Moody's to determine if an adjustment to the estimated A2-rated public utility bond was necessary. Since the Utility Proxy Group's average Moody's long-term issuer rating is A2/A3, another adjustment to the expected A2-rated public utility bond is needed to reflect the difference in bond ratings. An upward adjustment of 0.05%, which represents one-sixth of a recent spread between A2-rated and Baa2-rated public utility bond yields, is necessary to make the A2 prospective bond yield applicable to an A2/A3-rated public utility bond.[18] Adding the 0.05% to the 3.86% prospective A2-rated public utility bond yield results in a 3.91% expected bond yield applicable to the Utility Proxy Group.

Table 3: Summary of the Calculation of the Utility Proxy Group Projected Bond Yield[19]

Prospective Yield on Moody's Aaa-Rated Corporate Bonds (*Blue Chip)*	3.44%
Adjustment to Reflect Yield Spread Between Moody's Aaa-Rated Corporate Bonds and Moody's A2-Rated Utility Bonds	0.42%
Adjustment to Reflect the Utility Proxy Group's Average Moody's Bond Rating of A2/A3	0.05%
Prospective Bond Yield Applicable to the Utility Proxy Group	3.91%

[18] As shown on line 4 and explained in note 3, page 3 of Attachment DWD-3. Moody's does not provide public utility bond yields for A2/A3-rated bonds. As such, it was necessary to estimate the difference between A2-rated and A2/A3-rated public utility bonds. Because there are three steps between Baa2 and A2 (Baa2 to Baa1, Baa1 to A3, and A3 to A2) I assumed an adjustment of one-sixth of the difference between the A2-rated and Baa2-rated public utility bond yield was appropriate.

[19] As shown on page 3 of Attachment DWD-3.

To develop the indicated ROE using the total market approach RPM, this prospective bond yield is then added to the average of the three different equity risk premiums described below.

a. The Beta-Derived Risk Premium

Q. PLEASE EXPLAIN HOW THE BETA-DERIVED EQUITY RISK PREMIUM IS DETERMINED.

A. The components of the beta-derived risk premium model are: (1) an expected market equity risk premium over corporate bonds, and (2) the beta coefficient. The derivation of the beta-derived equity risk premium that I applied to the Utility Proxy Group is shown on lines 1 through 9, page 8 of Attachment DWD-3. The total beta-derived equity risk premium I applied is based on an average of three historical market data-based equity risk premiums, two *Value Line*-based equity risk premiums, and a Bloomberg-based equity risk premium. Each of these is described below.

Q. HOW DID YOU DERIVE A MARKET EQUITY RISK PREMIUM BASED ON LONG-TERM HISTORICAL DATA?

A. To derive a historical market equity risk premium, I used the most recent holding period returns for the large company common stocks from the Stocks, Bonds, Bills, and Inflation (SBBI) Yearbook 2021 (SBBI - 2021)[20] less the average historical yield on Moody's Aaa/Aa-rated corporate bonds for the period 1928 to 2020. Using holding period returns over a very long time is appropriate because it is consistent

[20] SBBI Appendix A Tables: Morningstar Stocks, Bonds, Bills, & Inflation 1926-2020.

with the long-term investment horizon presumed by investing in a going concern, *i.e.*, a company expected to operate in perpetuity.

SBBI's long-term arithmetic mean monthly total return rate on large company common stocks was 11.94%, and the long-term arithmetic mean monthly yield on Moody's Aaa/Aa-rated corporate bonds was 6.02%.[21] As shown on line 1, page 8 of Attachment DWD-3, subtracting the mean monthly bond yield from the total return on large company stocks results in a long-term historical equity risk premium of 5.92%.

I used the arithmetic mean monthly total return rates for the large company stocks and yields (income returns) for the Moody's Aaa/Aa corporate bonds, because they are appropriate for the purpose of estimating the cost of capital as noted in <u>SBBI - 2021.</u> [22] Using the arithmetic mean return rates and yields is appropriate because historical total returns and equity risk premiums provide insight into the variance and standard deviation of returns needed by investors in estimating future risk when making a current investment. If investors relied on the geometric mean of historical equity risk premiums, they would have no insight into the potential variance of future returns, because the geometric mean relates the change over many periods to a <u>constant</u> rate of change, thereby obviating the year-to-year fluctuations, or variance, which is critical to risk analysis.

[21] As explained in note 1, page 9 of Attachment DWD-3.
[22] <u>SBBI - 2020</u>, at 10-22 and 10-23.

Q. PLEASE EXPLAIN THE DERIVATION OF THE REGRESSION-BASED MARKET EQUITY RISK PREMIUM.

A. To derive the regression-based market equity risk premium of 8.83% shown on line 2, page 8 of Attachment DWD-3, I used the same monthly annualized total returns on large company common stocks relative to the monthly annualized yields on Moody's Aaa/Aa-rated corporate bonds as mentioned above. I modeled the relationship between interest rates and the market equity risk premium using the observed monthly market equity risk premium as the dependent variable, and the monthly yield on Moody's Aaa/Aa-rated corporate bonds as the independent variable. I then used a linear Ordinary Least Squares (OLS) regression, in which the market equity risk premium is expressed as a function of the Moody's Aaa/Aa-rated corporate bonds yield:

$$RP = \alpha + \beta\,(R_{Aaa/Aa})$$

Q. PLEASE EXPLAIN THE DERIVATION OF THE PRPM EQUITY RISK PREMIUM.

A. I used the same PRPM approach described above to the PRPM equity risk premium. The inputs to the model are the historical monthly returns on large company common stocks minus the monthly yields on Moody's Aaa/Aa-rated corporate bonds during the period from January 1928 through March 2021.[23] Using the previously discussed generalized form of ARCH, known as GARCH, the projected

[23] Data from January 1928 to December 2020 is from <u>SBBI - 2021</u>. Data from January 2021 to March 2021 is from Bloomberg.

equity risk premium is determined using Eviews© statistical software. The resulting PRPM predicted a market equity risk premium of 9.40%.[24]

Q. PLEASE EXPLAIN THE DERIVATION OF A PROJECTED EQUITY RISK PREMIUM BASED ON *VALUE LINE* DATA FOR YOUR RPM ANALYSIS.

A. As noted above, because both ratemaking and the cost of capital are prospective, a prospective market equity risk premium is needed. The derivation of the forecasted or prospective market equity risk premium can be found in note 4, page 8 of Attachment DWD-3. Consistent with my calculation of the dividend yield component in my DCF analysis, this prospective market equity risk premium is derived from an average of the three- to five-year median market price appreciation potential by *Value Line* for the 13 weeks ended April 2, 2021, plus an average of the median estimated dividend yield for the common stocks of the 1,700 firms covered in *Value Line*'s *Standard Edition*.[25]

The average median expected price appreciation is 29%, which translates to a 6.57% annual appreciation, and, when added to the average of *Value Line's* median expected dividend yields of 1.90%, equates to a forecasted annual total return rate on the market of 8.47%. The forecasted Moody's Aaa-rated corporate bond yield of 3.44% is deducted from the total market return of 8.47%, resulting in an equity risk premium of 5.03%, as shown on line 4, page 8 of Attachment DWD-3.

[24] Shown on line 3, page 8 of Attachment DWD-3.
[25] As explained in detail in note 1, page 2 of Attachment DWD-4.

Q. PLEASE EXPLAIN THE DERIVATION OF AN EQUITY RISK PREMIUM BASED ON THE S&P 500 COMPANIES.

A. Using data from *Value Line*, I calculated an expected total return on the S&P 500 companies using expected dividend yields and long-term growth estimates as a proxy for capital appreciation. The expected total return for the S&P 500 is 14.21%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 3.44% results in an 10.77% projected equity risk premium.

Q. PLEASE EXPLAIN THE DERIVATION OF AN EQUITY RISK PREMIUM BASED ON BLOOMBERG DATA.

A. Using data from Bloomberg, I calculated an expected total return on the S&P 500 using expected dividend yields and long-term growth estimates as a proxy for capital appreciation, identical to the method described above. The expected total return for the S&P 500 is 15.61%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 3.44% results in a 12.17% projected equity risk premium.

Q. WHAT IS YOUR CONCLUSION OF A BETA-DERIVED EQUITY RISK PREMIUM FOR USE IN YOUR RPM ANALYSIS?

A. I gave equal weight to all six equity risk premiums in arriving at a 8.69% equity risk premium.

Table 4: Summary of the Calculation of the Equity Risk Premium Using Total Market Returns[26]

Historical Spread Between Total Returns of Large Stocks and Aaa and Aa2-Rated Corporate Bond Yields (1928 – 2020)	5.92%
Regression Analysis on Historical Data	8.83%
PRPM Analysis on Historical Data	9.40%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected Aaa Corporate Bond Yields	5.03%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P 500 less Projected Aaa Corporate Bond Yields	10.77%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P 500 less Projected Aaa Corporate Bond Yields	12.17%
Average	8.69%

After calculating the average market equity risk premium of 8.69%, I adjusted it by the beta coefficient to account for the risk of the Utility Proxy Group. As discussed below, the beta coefficient is a meaningful measure of prospective relative risk to the market as a whole, and is a logical way to allocate a company's, or proxy group's, share of the market's total equity risk premium relative to corporate bond yields. As shown on page 1 of Attachment DWD-4, the average of the mean and median beta coefficient for the Utility Proxy Group is 0.92. Multiplying the 0.92 average by the market equity risk premium of 8.69% results in a beta-adjusted equity risk premium for the Utility Proxy Group of 7.99%.

[26] As shown on page 8 of Attachment DWD-3.

b. The S&P Utility Index Derived Risk Premium

Q. HOW DID YOU DERIVE THE EQUITY RISK PREMIUM BASED ON THE S&P UTILITY INDEX AND MOODY'S A-RATED PUBLIC UTILITY BONDS?

A. I estimated three equity risk premiums based on S&P Utility Index holding period returns, and two equity risk premiums based on the expected returns of the S&P Utilities Index, using *Value Line* and Bloomberg data, respectively. Turning first to the S&P Utility Index holding period returns, I derived a long-term monthly arithmetic mean equity risk premium between the S&P Utility Index total returns of 10.65%, and monthly Moody's A-rated public utility bond yields of 6.49% from 1928 to 2020, to arrive at an equity risk premium of 4.16%.[27] I then used the same historical data to derive an equity risk premium of 6.45% based on a regression of the monthly equity risk premiums. The final S&P Utility Index holding period equity risk premium involved applying the PRPM using the historical monthly equity risk premiums from January 1928 to March 2021 to arrive at a PRPM-derived equity risk premium of 4.77% for the S&P Utility Index.

I then derived expected total returns on the S&P Utilities Index of 10.61% and 9.58% using data from *Value Line* and Bloomberg, respectively, and subtracted the prospective Moody's A2-rated public utility bond yield of 3.86%[28], which resulted in equity risk premiums of 6.75% and 5.72%, respectively. As with the market equity risk premiums, I averaged each risk premium to arrive at my utility-specific equity risk premium of 5.57%.

[27] As shown on line 1, page 12 of Attachment DWD-3.
[28] Derived on line 3, page 3 of Attachment DWD-3.

Table 5: Summary of the Calculation of the Equity Risk Premium Using S&P Utility Index Holding Returns[29]

Historical Spread Between Total Returns of the S&P Utilities Index and A2-Rated Utility Bond Yields (1928 – 2020)	4.16%
Regression Analysis on Historical Data	6.45%
PRPM Analysis on Historical Data	4.77%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P Utilities Index less Projected A2 Utility Bond Yields	6.75%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P Utilities Index less Projected A2 Utility Bond Yields	5.72%
Average	5.57%

c. Authorized Return-Derived Equity Risk Premium

Q. HOW DID YOU DERIVE AN EQUITY RISK PREMIUM OF 5.69% BASED ON AUTHORIZED ROES FOR GAS DISTRIBUTION UTILITIES?

A. The equity risk premium of 5.69% shown on line 3, page 7 of Attachment DWD-3 is the result of a regression analysis based on regulatory awarded ROEs related to the yields on Moody's A-rated public utility bonds. That analysis is shown on page 13 of Attachment DWD-3 which contains the graphical results of a regression analysis of 798 rate cases for gas distribution utilities which were fully litigated during the period from January 1, 1980 through March 31, 2021. It shows the implicit equity risk premium relative to the yields on A-rated public utility bonds immediately prior to the issuance of each regulatory decision. It is readily discernible that there is an inverse relationship between the yield on A-rated public utility bonds and equity risk premiums. In other words, as interest rates decline, the equity risk premium rises and vice versa, a result consistent with financial literature

[29] As shown on page 12 of Attachment DWD-3.

on the subject.[30] I used the regression results to estimate the equity risk premium applicable to the projected yield on Moody's A2-rated public utility bonds of 3.86%. Given the expected A-rated utility bond yield of 3.86%, it can be calculated that the indicated equity risk premium applicable to that bond yield is 5.69%, which is shown on line 3, page 7 of Attachment DWD-3.

Q. WHAT IS YOUR CONCLUSION OF AN EQUITY RISK PREMIUM FOR USE IN YOUR TOTAL MARKET APPROACH RPM ANALYSIS?

A. The equity risk premium I apply to the Utility Proxy Group is 6.42%, which is the average of the beta-adjusted equity risk premium for the Utility Proxy Group, the S&P Utilities Index, and the authorized return utility equity risk premiums of 7.99%, 5.57%, and 5.69%, respectively.[31]

Q. WHAT IS THE INDICATED RPM COMMON EQUITY COST RATE BASED ON THE TOTAL MARKET APPROACH?

A. As shown on line 7, page 3 of Attachment DWD-3, I calculated a common equity cost rate of 10.33% for the Utility Proxy Group based on the total market approach RPM.

Table 6: Summary of the Total Market Return Risk Premium Model[32]

Prospective Moody's A2/A3-Rated Utility Bond Applicable to the Utility Proxy Group	3.91%
Prospective Equity Risk Premium	6.42%
Indicated Cost of Common Equity	10.33%

[30] *See, e.g.*, Robert S. Harris and Felicia C. Marston, *The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts*, Journal of Applied Finance, Vol. 11, No. 1, 2001, at pages 11 to 12; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, Spring 1985, at pages 33 to 45.

[31] As shown on page 7 of Attachment DWD-3.

[32] As shown on page 3 of Attachment DWD-3.

Q. WHAT ARE THE RESULTS OF YOUR APPLICATION OF THE PRPM AND THE TOTAL MARKET APPROACH RPM?

A. As shown on page 1 of Attachment DWD-3, the indicated RPM-derived common equity cost rate is 10.65%, which gives equal weight to the PRPM (10.96%) and the adjusted-market approach results (10.33%).

C. <u>The Capital Asset Pricing Model</u>

Q. PLEASE EXPLAIN THE THEORETICAL BASIS OF THE CAPM.

A. CAPM theory defines risk as the co-variability of a security's returns with the market's returns as measured by the beta coefficient (β). A beta coefficient less than 1.0 indicates lower variability than the market as a whole, while a beta coefficient greater than 1.0 indicates greater variability than the market.

The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. In addition, the CAPM presumes that investors only require compensation for systematic risk, which is the result of macroeconomic and other events that affect the returns on all assets. The model is applied by adding a risk-free rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk of the individual security relative to the total market as measured by the beta coefficient. The traditional CAPM model is expressed as:

$$R_s = R_f + \beta (R_m - R_f)$$

Where:	R_s	=	Return rate on the common stock
	R_f	=	Risk-free rate of return
	R_m	=	Return rate on the market as a whole

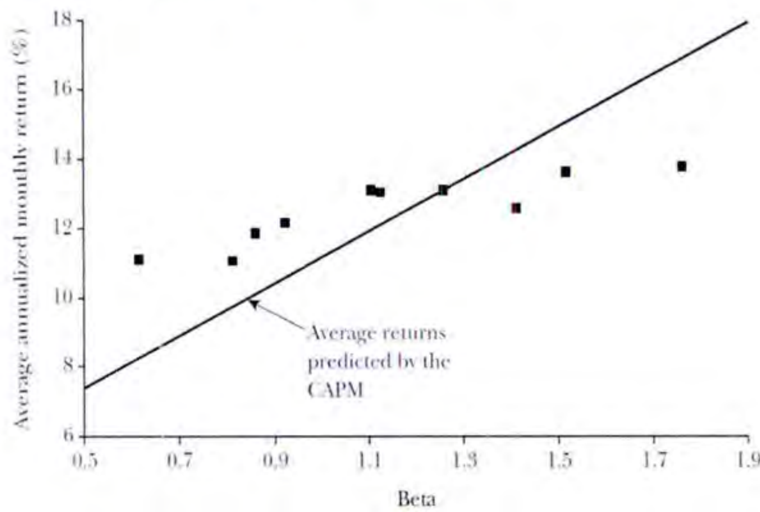
β = Adjusted beta coefficient (volatility of the security relative to the market as a whole)

Numerous tests of the CAPM have measured the extent to which security returns and beta coefficients are related as predicted by the CAPM, confirming its validity. The empirical CAPM (ECAPM) reflects the reality that while the results of these tests support the notion that the beta coefficient is related to security returns, the empirical Security Market Line (SML) described by the CAPM formula is not as steeply sloped as the predicted SML.[33]

The ECAPM reflects this empirical reality. Fama and French clearly state regarding Figure 2, below, that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low." [34]

Figure 2 http://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430

Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on Prior Beta, 1928–2003



[33] Roger A. Morin, New Regulatory Finance (Public Utility Reports, Inc., 2006), at 175. (Morin)

[34] Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence", *Journal of Economic Perspectives*, Vol. 18, No. 3, Summer 2004 at 33 (Fama & French).

In addition, Morin observes that while the results of these tests support the notion that beta is related to security returns, the empirical SML described by the CAPM formula is not as steeply sloped as the predicted SML. Morin states:

> With few exceptions, the empirical studies agree that ... low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.[35]
>
> * * *
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $$K = R_F + x\,\beta(R_M - R_F) + (1-x)\,\beta(R_M - R_F)$$
>
> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship [is] Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $$K = R_F + 0.25(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$[36]

Fama and French provide similar support for the ECAPM when they state:

> The early tests firmly reject the Sharpe-Lintner version of the CAPM. There is a positive relation between beta and average return, but it is too 'flat.'... The regressions consistently find that the intercept is greater than the average risk-free rate... and the coefficient on beta is less than the average excess market return... This is true in the early tests... as well as in more recent cross-section regressions tests, like Fama and French (1992).[37]

Finally, Fama and French further note:

> Confirming earlier evidence, the relation between beta and average return for the ten portfolios is much flatter than the Sharpe-Linter CAPM predicts. The returns on low beta portfolios are too high, and the returns on the high beta portfolios are too low. For example, the predicted return on the portfolio with the lowest beta is 8.3 percent per year; the actual return as 11.1 percent. The predicted return on the portfolio with the t beta is 16.8 percent per year; the actual is 13.7 percent.[38]

[35] Morin, at 175.
[36] Morin, at 190.
[37] Fama & French, at 32.
[38] *Ibid.*, at 33.

Clearly, the justification from Morin, Fama, and French, along with their reviews of other academic research on the CAPM, validate the use of the ECAPM. In view of theory and practical research, I have applied both the traditional CAPM and the ECAPM to the companies in the Utility Proxy Group and averaged the results.

Q. WHAT BETA COEFFICIENTS DID YOU USE IN YOUR CAPM ANALYSIS?

A. For the beta coefficients in my CAPM analysis, I considered two sources: *Value Line* and Bloomberg Professional Services. While both of those services adjust their calculated (or "raw") beta coefficients to reflect the tendency of the beta coefficient to regress to the market mean of 1.00, *Value Line* calculates the beta coefficient over a five-year period, while Bloomberg calculates it over a two-year period.

Q. PLEASE DESCRIBE YOUR SELECTION OF A RISK-FREE RATE OF RETURN.

A. As discussed previously, the risk-free rate adopted for both applications of the CAPM is 2.73%. This risk-free rate is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the third calendar quarter of 2022, and long-term projections for the years 2022 to 2026 and 2027 to 2031.

Q. PLEASE EXPLAIN THE ESTIMATION OF THE EXPECTED RISK PREMIUM FOR THE MARKET USED IN YOUR CAPM ANALYSES.

A. The basis of the market risk premium is explained in detail in note 1 on Attachment DWD-4. As discussed above, the market risk premium is derived from an average of three historical data-based market risk premiums, two *Value Line* data-based market risk premiums, and one Bloomberg data-based market risk premium.

The long-term income return on U.S. Government securities of 5.05% was deducted from the SBBI - 2021 monthly historical total market return of 12.20%, which results in an historical market equity risk premium of 7.15%.[39] I applied a linear OLS regression to the monthly annualized historical returns on the S&P 500 relative to historical yields on long-term U.S. Government securities from SBBI - 2021. That regression analysis yielded a market equity risk premium of 9.54%. The PRPM market equity risk premium is 10.46% and is derived using the PRPM relative to the yields on long-term U.S. Treasury securities from January 1926 through March 2021.

The *Value Line*-derived forecasted total market equity risk premium is derived by deducting the forecasted risk-free rate of 2.73%, discussed above, from the *Value Line* projected total annual market return of 8.47%, resulting in a forecasted total market equity risk premium of 5.74%. The S&P 500 projected market equity risk premium using *Value Line* data is derived by subtracting the projected risk-free rate of 2.73% from the projected total return of the S&P 500 of 14.21%. The resulting market equity risk premium is 11.48%.

The S&P 500 projected market equity risk premium using Bloomberg data is derived by subtracting the projected risk-free rate of 2.73% from the projected total return of the S&P 500 of 15.61%. The resulting market equity risk premium

[39] SBBI - 2021, at Appendix A-1 (1) through A-1 (3) and Appendix A-7 (19) through A-7 (21).

is 12.88%. These six measures, when averaged, result in an average total market equity risk premium of 9.54%.

Table 7: Summary of the Calculation of the Market Risk Premium for Use in the CAPM[40]

Historical Spread Between Total Returns of Large Stocks and Long-Term Government Bond Yields (1926 – 2020)	7.15%
Regression Analysis on Historical Data	9.54%
PRPM Analysis on Historical Data	10.46%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected 30-Year Treasury Bond Yields	5.74%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P 500 less Projected 30-Year Treasury Bond Yields	11.48%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P 500 less Projected 30-Year Treasury Bond Yields	12.88%
Average	9.54%

Q. WHAT ARE THE RESULTS OF YOUR APPLICATION OF THE TRADITIONAL AND EMPIRICAL CAPM TO THE UTILITY PROXY GROUP?

A. As shown on page 1 of Attachment DWD-4, the mean result of my CAPM/ECAPM analyses is 11.64%, the median is 11.60%, and the average of the two is 11.62%. Consistent with my reliance on the average of mean and median DCF results discussed above, the indicated common equity cost rate using the CAPM/ECAPM is 11.62%.

[40] As shown on page 2 of Attachment DWD-4.

D. Common Equity Cost Rates for a Proxy Group of Domestic, Non-Price Regulated Companies Based on the DCF, RPM, and CAPM

Q. WHY DO YOU ALSO CONSIDER A PROXY GROUP OF DOMESTIC, NON-PRICE REGULATED COMPANIES?

A. In the *Hope* and *Bluefield* cases, the U.S. Supreme Court did not specify that comparable risk companies had to be utilities. Since the purpose of rate regulation is to be a substitute for marketplace competition, non-price regulated firms operating in the competitive marketplace make an excellent proxy group if they are comparable in total risk to the Utility Proxy Group being used to estimate the cost of common equity. The selection of such domestic, non-price regulated competitive firms theoretically and empirically results in a proxy group which is comparable in total risk to the Utility Proxy Group, since all of these companies compete for capital in the exact same markets.

Q. HOW DID YOU SELECT NON-PRICE REGULATED COMPANIES THAT ARE COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUP?

A. In order to select a proxy group of domestic, non-price regulated companies similar in total risk to the Utility Proxy Group, I relied on the beta coefficients and related statistics derived from *Value Line* regression analyses of weekly market prices over the most recent 260 weeks (*i.e.*, five years). These selection criteria resulted in a proxy group of 48 domestic, non-price regulated firms comparable in total risk to the Utility Proxy Group. Total risk is the sum of non-diversifiable market risk and diversifiable company-specific risks. The criteria used in selecting the domestic, non-price regulated firms was:

(i) They must be covered by *Value Line Investment Survey* (Standard Edition);

(ii) They must be domestic, non-price regulated companies, *i.e.*, not utilities;

(iii) Their beta coefficients must lie within plus or minus two standard deviations of the average unadjusted beta coefficients of the Utility Proxy Group; and

(iv) The residual standard errors of the *Value Line* regressions which gave rise to the unadjusted beta coefficients must lie within plus or minus two standard deviations of the average residual standard error of the Utility Proxy Group.

Beta coefficients measure market, or systematic, risk, which is not diversifiable. The residual standard errors of the regressions measure each firm's company-specific, diversifiable risk. Companies that have similar beta coefficients <u>and</u> similar residual standard errors resulting from the same regression analyses have similar total investment risk.

Q. HAVE YOU PREPARED AN ATTACHMENT WHICH SHOWS THE DATA FROM WHICH YOU SELECTED THE 48 DOMESTIC, NON-PRICE REGULATED COMPANIES THAT ARE COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUP?

A. Yes, the basis of my selection and both proxy groups' regression statistics are shown in Attachment DWD-5.

Q. DID YOU CALCULATE COMMON EQUITY COST RATES USING THE DCF MODEL, RPM, AND CAPM FOR THE NON-PRICE REGULATED PROXY GROUP?

A. Yes. Because the DCF model, RPM, and CAPM have been applied in an identical manner as described above, I will not repeat the details of the rationale and application of each model. One exception is in the application of the RPM, where I did not use public utility-specific equity risk premiums, nor did I apply the PRPM to the individual non-price regulated companies.

Page 2 of Attachment DWD-6 derives the constant growth DCF model common equity cost rate. As shown, the indicated common equity cost rate, using the constant growth DCF for the Non-Price Regulated Proxy Group comparable in total risk to the Utility Proxy Group, is 12.60%.

Pages 3 through 5 of Attachment DWD-6 contain the data and calculations that support the 12.35% RPM common equity cost rate. As shown on line 1, page 3 of Attachment DWD-6, the consensus prospective yield on Moody's Baa-rated corporate bonds for the six quarters ending in the third quarter of 2022, and for the years 2022 to 2026 and 2027 to 2031, is 4.36%.[41]

When the beta-adjusted risk premium of 7.99%[42] relative to the Non-Price Regulated Proxy Group is added to the prospective Baa2-rated corporate bond yield of 4.36%, the indicated RPM common equity cost rate is 12.35%.

Page 6 of Attachment DWD-6 contains the inputs and calculations that support my indicated CAPM/ECAPM common equity cost rate of 11.59%.

Q. HOW IS THE COST RATE OF COMMON EQUITY BASED ON THE NON-PRICE REGULATED PROXY GROUP COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUP?

A. As shown on page 1 of Attachment DWD-6, the results of the common equity models applied to the Non-Price Regulated Proxy Group -- which group is

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[41] *Blue Chip Financial Forecasts*, December 1, 2020, at page 14 and April 1, 2021, at page 2.

[42] Derived on page 5 of Attachment DWD-6.

comparable in total risk to the Utility Proxy Group -- are as follows: 12.60% (DCF), 12.35% (RPM), and 11.59% (CAPM). The average of the mean and median of these models is 12.27%, which I used as the indicated common equity cost rates for the Non-Price Regulated Proxy Group.

V. CONCLUSION OF COMMON EQUITY COST RATE BEFORE ADJUSTMENTS

Q. WHAT ARE THE INDICATED COMMON EQUITY COST RATES BEFORE ADJUSTMENTS?

A. By applying multiple cost of common equity models to the Utility Proxy Group and the Non-Price Regulated Proxy Group, the indicated range of common equity cost rates before any relative risk adjustment is between 9.57% and 12.27%. The spread between the high and low values in the range (270 basis points) may indicate that there is still uncertainty around the recovery from the COVID-19 pandemic. I used multiple cost of common equity models as primary tools in arriving at my recommended common equity cost rate, because no single model is so inherently precise that it can be relied on to the exclusion of other theoretically sound models. Using multiple models adds reliability to the estimated common equity cost rate, with the prudence of using multiple cost of common equity models supported in both the financial literature and regulatory precedent.

VI. ADJUSTMENTS TO THE COMMON EQUITY COST RATE

A. Size Adjustment

Q. DOES DUKE ENERGY KENTUCKY'S SMALLER SIZE RELATIVE TO THE UTILITY PROXY GROUP COMPANIES INCREASE ITS BUSINESS RISK?

A. Yes. Duke Energy Kentucky's smaller size relative to the Utility Proxy Group companies indicates greater relative business risk for the Company because, all else being equal, size has a material bearing on risk.

Size affects business risk because smaller companies generally are less able to cope with significant events that affect sales, revenues and earnings. For example, smaller companies face more risk exposure to business cycles and economic conditions, both nationally and locally. Additionally, the loss of revenues from a few larger customers would have a greater effect on a small company than on a bigger company with a larger, more diverse, customer base.

As further evidence that smaller firms are riskier, investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities. Duff & Phelps 2020 Valuation Handbook Guide to Cost of Capital - Market Results through 2019 (D&P - 2020) discusses the nature of the small-size phenomenon, providing an indication of the magnitude of the size premium based on several measures of size. In discussing "Size as a Predictor of Equity Premiums," D&P - 2020 states:

> The size effect is based on the empirical observation that companies of smaller size are associated with greater risk and, therefore, have greater cost of capital [sic]. The "size" of a company is one of the most important risk elements to consider when developing cost of equity capital estimates for use in valuing a business simply because

> size has been shown to be a *predictor* of equity returns. In other words, there is a significant (negative) relationship between size and historical equity returns - as size *decreases*, returns tend to *increase*, and vice versa. (footnote omitted) (emphasis in original)[43]

Furthermore, in "The Capital Asset Pricing Model: Theory and Evidence," Fama and French note size is indeed a risk factor which must be reflected when estimating the cost of common equity. On page 14, they note:

> . . . the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns not captured in the market return and are priced separately from market betas.[44]

Based on this evidence, Fama and French proposed their three-factor model which includes a size variable in recognition of the effect size has on the cost of common equity.

Also, it is a basic financial principle that the use of funds invested, and not the source of funds, is what gives rise to the risk of any investment.[45] Eugene Brigham, a well-known authority, states:

> A number of researchers have observed that portfolios of small-firms (sic) have earned consistently higher average returns than those of large-firm stocks; this is called the "small-firm effect." On the surface, it would seem to be advantageous to the small firms to provide average returns in a stock market that are higher than those of larger firms. In reality, it is bad news for the small firm; **what the small-firm effect means is that the capital market demands higher returns on stocks of small firms than on otherwise similar stocks of the large firms**. (emphasis added)[46]

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[43] Duff & Phelps Valuation Handbook – U.S. Guide to Cost of Capital, Wiley 2020, at 4-1.
[44] Fama and French, at 25-43.
[45] Brealey, Richard A. and Myers, Stewart C., Principles of Corporate Finance (McGraw-Hill Book Company, 1996), at 204-205, 229.
[46] Brigham, Eugene F., Fundamentals of Financial Management, Fifth Edition (The Dryden Press, 1989), at 623.

Consistent with the financial principle of risk and return discussed above, increased relative risk due to small size must be considered in the allowed rate of return on common equity. Therefore, the Commission's authorization of a cost rate of common equity in this proceeding must appropriately reflect the unique risks of Duke Energy Kentucky, including its small size, which is justified and supported above by evidence in the financial literature.

Q. IS THERE A WAY TO QUANTIFY A RELATIVE RISK ADJUSTMENT DUE TO DUKE ENERGY KENTUCKY'S SMALL SIZE RELATIVE TO THE UTILITY PROXY GROUP?

A. Yes. Duke Energy Kentucky has greater relative risk than the average utility in the Utility Proxy Group because of its smaller size compared with the utilities in that group, as measured by an estimated market capitalization of common equity for Duke Energy Kentucky.

Table 8: Size as Measured by Market Capitalization for Duke Energy Kentucky and the Utility Proxy Group

	Market Capitalization* ($ Millions)	Times Greater than The Company
Duke Energy Kentucky	$1,241.112	
Utility Proxy Group	$4,574.713	3.7x
*From page 1 of Attachment DWD-7.		

Duke Energy Kentucky's estimated market capitalization was $1.2 billion as of March 31, 2021,[47] compared with the market capitalization of the average

[47] $718.236M (company-provided book equity as of the 4th Quarter 2020) * 172.8% (market-to-book ratio of the Utility Proxy Group) as demonstrated on page 2 of Attachment DWD-7.

company in the Utility Proxy Group of $4.6 billion as of March 31, 2021. The average company in the Utility Proxy Group has a market capitalization 3.7 times the size of Duke Energy Kentucky's estimated market capitalization.

As a result, it is necessary to upwardly adjust the range of indicated common equity cost rates between 9.57% to 12.27% to reflect Duke Energy Kentucky's greater risk due to their smaller relative size. The determination is based on the size premiums for portfolios of New York Stock Exchange, American Stock Exchange, and NASDAQ listed companies ranked by deciles for the 1926 to 2020 period. The average size premium for the Utility Proxy Group with a market capitalization of $4.6 billion falls in the 4th decile, while the Company's estimated market capitalization of $1.2 billion places it in the 7th decile. The size premium spread between the 4th decile and the 7th decile is 0.79%. Even though a 0.79% upward size adjustment is indicated, I applied a size premium of 0.15% to the Company's range of indicated common equity cost rates.

Q. SINCE DUKE ENERGY KENTUCKY IS A SUBSIDIARY OF DUK, WHY IS THE SIZE OF THE TOTAL COMPANY NOT MORE APPROPRIATE TO USE WHEN DETERMINING THE SIZE ADJUSTMENT?

A. As discussed previously, rates are set using the stand-alone principle, which maintains that the utility operations of a diversified firm should be regulated as though they were independent (*i.e.*, without subsidies to or from affiliated companies). Because of this, the return derived in this proceeding will not apply to DUK as a whole, but only Duke Energy Kentucky's gas distribution operations. DUK is the sum of its constituent parts, including those constituent parts' ROEs.

Potential investors in the Company are aware that it is a combination of operations in each state, and that each state's operations experience the operating risks specific to their jurisdiction. The market's expectation of DUK's return is commensurate with the realities of its composite operations in each of the states in which it operates.

B. Credit Risk Adjustment

Q. PLEASE DISCUSS YOUR PROPOSED CREDIT RISK ADJUSTMENT.

A. Duke Energy Kentucky's long-term issuer ratings are Baa1 and BBB+ from Moody's Investors Services and S&P, respectively, which are riskier than the average long-term issuer ratings for the Utility Proxy Group of A2/A3 and A-, respectively.[48] Hence, an upward credit risk adjustment is necessary to reflect the lower credit rating, *i.e.*, Baa1, of Duke Energy Kentucky relative to the A2/A3 average Moody's bond rating of the Utility Proxy Group.[49]

An indication of the magnitude of the necessary upward adjustment to reflect the greater credit risk inherent in a Baa1 bond rating is one-half of a recent three-month average spread between Moody's A2 and Baa2-rated public utility bond yields of 0.27%, shown on page 4 of Attachment DWD-3, or 0.14%.[50]

C. Flotation Cost Adjustment

Q. WHAT ARE FLOTATION COSTS?

A. Flotation costs are those costs associated with the sale of new issuances of common stock. They include market pressure and the mandatory unavoidable costs of

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[48] Source: S&P Global Market Intelligence.
[49] As shown on page 5 of Attachment DWD-3.
[50] 0.14% = 0.27% * (1/2).

issuance (*e.g.*, underwriting fees and out-of-pocket costs for printing, legal, registration, etc.). For every dollar raised through debt or equity offerings, the Company receives less than one full dollar in financing.

Q. WHY IS IT IMPORTANT TO RECOGNIZE FLOTATION COSTS IN THE ALLOWED COMMON EQUITY COST RATE?

A. It is important because there is no other mechanism in the ratemaking paradigm through which such costs can be recognized and recovered. Because these costs are real, necessary, and legitimate, recovery of these costs should be permitted. As noted by Morin:

> The costs of issuing these securities are just as real as operating and maintenance expenses or costs incurred to build utility plants, and fair regulatory treatment must permit recovery of these costs….
>
> The simple fact of the matter is that common equity capital is not free….[Flotation costs] must be recovered through a rate of return adjustment.[51]

Q. SHOULD FLOTATION COSTS BE RECOGNIZED ONLY IF THERE WAS AN ISSUANCE DURING THE TEST YEAR OR THERE IS AN IMMINENT POST-TEST YEAR ISSUANCE OF ADDITIONAL COMMON STOCK?

A. No. As noted above, there is no mechanism to recapture such costs in the ratemaking paradigm other than an adjustment to the allowed common equity cost rate. Flotation costs are charged to capital accounts and are not expensed on a utility's income statement. As such, flotation costs are analogous to capital investments, albeit negative, reflected on the balance sheet. Recovery of capital investments relates to the expected useful lives of the investment. Since common

[51] Morin, at p. 321.

equity has a very long and indefinite life (assumed to be infinity in the standard regulatory DCF model), flotation costs should be recovered through an adjustment to common equity cost rate, even when there has not been an issuance during the test year, or in the absence of an expected imminent issuance of additional shares of common stock.

Historical flotation costs are a permanent loss of investment to the utility and should be accounted for. When any company, including a utility, issues common stock, flotation costs are incurred for legal, accounting, printing fees and the like. For each dollar of issuing market price, a small percentage is expensed and is permanently unavailable for investment in utility rate base. Since these expenses are charged to capital accounts and not expensed on the income statement, the only way to restore the full value of that dollar of issuing price with an assumed investor required return of 10% is for the net investment, \$0.95, to earn more than 10% to net back to the investor a fair return on that dollar. In other words, if a company issues stock at \$1.00 with 5% in flotation costs, it will net \$0.95 in investment. Assuming the investor in that stock requires a 10% return on his or her invested \$1.00 (*i.e.*, a return of \$0.10), the company needs to earn approximately 10.5% on its invested \$0.95 to receive a \$0.10 return.

Q. DO THE COMMON EQUITY COST RATE MODELS YOU HAVE USED ALREADY REFLECT INVESTORS' ANTICIPATION OF FLOTATION COSTS?

A. No. All of these models assume no transaction costs. The literature is quite clear that these costs are not reflected in the market prices paid for common stocks. For example, Brigham and Daves confirm this and provide the methodology utilized to calculate the flotation adjustment.[52] In addition, Morin confirms the need for such an adjustment even when no new equity issuance is imminent.[53] Consequently, it is proper to include a flotation cost adjustment when using cost of common equity models to estimate the common equity cost rate.

Q. HOW DID YOU CALCULATE THE FLOTATION COST ALLOWANCE?

A. I modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs in accordance with the method cited in literature by Brigham and Daves, as well as by Morin. The flotation cost adjustment recognizes the actual costs of issuing equity that were incurred by DUK in its last three equity issuances. Based on the issuance costs shown on page 1 of Attachment DWD-8, an adjustment of 0.12% is required to reflect the flotation costs applicable to the Utility Proxy Group.

D. Other Considerations

Q. ARE YOU AWARE THAT THE COMPANY HAS PROPOSED A GOVERNMENT MANDATE ADJUSTMENT MECHANISM (RIDER GMA) IN THIS CASE?

A. Yes, I understand the Company's proposed Rider GMA is a mechanism that would allow the Company to track and adjust rates based on possible changes to the Federal corporate tax rate and existing or new regulations on pipeline replacement and operational safety through the U.S. Department of Transportation Pipeline and

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[52] Eugene F. Brigham and Phillip R. Daves, Intermediate Financial Management, 9th Edition, Thomson/Southwestern, at p. 342.

[53] Morin, at pp. 327-30.

Hazardous Materials Safety Administration (PHMSA). Under that structure, over-recovery of authorized revenue would produce a rate decrease in future periods; under-recovery would result in a rate increase.

Q. DOES THE PRESENCE OF REGULATORY MECHANISMS LIKE THE RIDER GMA IN THE COMPANY'S RATES AFFECT ITS RELATIVE RISK?

A. No. The cost of capital is a comparative exercise, so if the mechanism is common throughout the companies on which one bases their analyses on, the comparative risk is zero, because any impact of the perceived reduced risk of the mechanism(s) by investors would be reflected in the market data of the proxy group. To that point, as shown on Attachment DWD-9 every single one of the proxy companies has rate stabilization mechanisms in at least one of their jurisdictions.

Q. ARE YOU AWARE OF ANY STUDIES THAT HAVE ADDRESSED THE RELATIONSHIP BETWEEN RATE STABILIZATION MECHANISMS, GENERALLY, AND ROE?

A. Yes. I, along with Richard A. Michelfelder of Rutgers University, and my colleague at ScottMadden, Pauline M. Ahern, examined the relationship between rate stabilization mechanisms and ROE among electric, gas, and water utilities. Using the generalized consumption asset pricing model, also known as the PRPM, we found decoupling to have no statistically significant effect on investor perceived risk, and hence, ROE.[54]

[54] Richard A. Michelfelder, Pauline M. Ahern, Dylan W. D'Ascendis, *The Impact of Decoupling on The Cost of Capital of Public Utilities*, Energy Policy 130 (2019), at 311-319.

Also, in March 2014, The Brattle Group (Brattle) published a study addressing the effect of revenue decoupling structures on the cost of capital for electric utilities.[55] In its report, which extended a prior analysis focused on natural gas distribution utilities, Brattle pointed out that although decoupling structures may affect revenues, net income still can vary. Brattle further noted that the distinction between diversifiable and non-diversifiable risk is important to equity investors, and the relationship between decoupling and ROE should be examined in that context. Further to that point, Brattle noted that although reductions in total risk may be important to bondholders, only reductions in non-diversifiable business risk would justify a reduction to the ROE. In November 2016, the Brattle study was updated based on data through the fourth quarter of 2015.[56]

Brattle's empirical analysis examined the relationship between decoupling and the After-Tax WACC for a group of electric utilities that had implemented decoupling structures in various jurisdictions throughout the United States. As with Brattle's 2014 study, the updated study found no statistically significant link between the cost of capital and revenue decoupling structures.[57]

In view of all of the above, Duke Energy Kentucky's ROE should not be affected if Rider GMA is approved in this proceeding.

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[55] The Brattle Group, *The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation*, Prepared for the Energy Foundation, March 20, 2014.

[56] Michael J. Vilbert, Joseph B. Wharton, Shirley Zhang and James Hall, *Effect on the Cost of Capital of Innovative Ratemaking that Relaxes the Linkage between Revenue and kWh Sales – An Updated Empirical Investigation*, November 2016.

[57] *Ibid.*

Q. WHAT IS THE INDICATED COST OF COMMON EQUITY AFTER YOUR COMPANY-SPECIFIC ADJUSTMENTS?

Applying the 0.15% size adjustment, the 0.14% credit risk adjustment, and the 0.12% flotation cost adjustment to the indicated cost of common equity range of 9.57% to 12.27% results in a Company-specific cost of common equity rate range of 9.98% to 12.68%. Considering the wide range of results produced by the models, which may indicate uncertainty surrounding the COVID-19 pandemic resolution, I recommend an ROE at the lower end of my range, or 10.30%, as applicable to Duke Energy Kentucky at this time.

VII. <u>CONCLUSION</u>

Q. WHAT IS YOUR RECOMMENDED ROE FOR DUKE ENERGY KENTUCKY?

A. Given the indicated ROE range applicable to the Utility Proxy Group of 9.57% to 12.27% and the Company-specific ROE range of 9.98% to 12.68%, I conclude that an appropriate ROE for the Company is 10.30%.

Q. IN YOUR OPINION, IS YOUR PROPOSED ROE OF 10.30% FAIR AND REASONABLE TO DUKE ENERGY KENTUCKY AND ITS CUSTOMERS?

A. Yes, it is.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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MANAGEMENT CONSULTANTS

Appendix A - Resume & Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Director

Summary

Dylan is an experienced consultant and a Certified Rate of Return Analyst (CRRA) and Certified Valuation Analyst (CVA). He has served as a consultant for investor-owned and municipal utilities and authorities for 12 years. Dylan has extensive experience in rate of return analyses, class cost of service, rate design, and valuation for regulated public utilities. He has testified as an expert witness in the subjects of rate of return, cost of service, rate design, and valuation before 30 regulatory commissions in the U.S., one Canadian province, and an American Arbitration Association panel.

He also maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured.

Areas of Specialization

- Regulation and Rates
- Utilities
- Mutual Fund Benchmarking
- Capital Market Risk
- Financial Modeling
- Valuation
- Regulatory Strategy
- Rate Case Support
- Rate of Return
- Cost of Service
- Rate Design

Recent Expert Testimony Submission/Appearances

Jurisdiction	*Topic*
Massachusetts Department of Public Utilities	Rate of Return
New Jersey Board of Public Utilities	Rate of Return
Hawaii Public Utilities Commission	Cost of Service, Rate Design
South Carolina Public Service Commission	Return on Common Equity
American Arbitration Association	Valuation

Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies
- Maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured
- Sponsored valuation testimony for a large municipal water company in front of an American Arbitration Association Board to justify the reasonability of their lease payments to the City
- Co-authored a valuation report on behalf of a large investor-owned utility company in response to a new state regulation which allowed the appraised value of acquired assets into rate base

Recent Publications and Speeches

- Co-Author of: "Decoupling, Risk Impacts and the Cost of Capital", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. The Electricity Journal, March, 2020.
- Co-Author of: "Decoupling Impact and Public Utility Conservation Investment", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. Energy Policy Journal, 130 (2019), 311-319.
- "Establishing Alternative Proxy Groups", before the Society of Utility and Regulatory Financial Analysts: 51st Financial Forum, April 4, 2019, New Orleans, LA.
- "Past is Prologue: Future Test Year", Presentation before the National Association of Water Companies 2017 Southeast Water Infrastructure Summit, May 2, 2017, Savannah, GA.
- Co-author of: "Comparative Evaluation of the Predictive Risk Premium Model™, the Discounted Cash Flow Model and the Capital Asset Pricing Model", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University, Pauline M. Ahern, and Frank J. Hanley, The Electricity Journal, May, 2013.
- "Decoupling: Impact on the Risk and Cost of Common Equity of Public Utility Stocks", before the Society of Utility and Regulatory Financial Analysts: 45th Financial Forum, April 17-18, 2013, Indianapolis, IN.

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MANAGEMENT CONSULTANTS

Resume & Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Director

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Regulatory Commission of Alaska				
Alaska Power Company	09/20	Alaska Power Company; Goat Lake Hydro, Inc.; BBL Hydro, Inc.	Tariff Nos. TA886-2; TA6-521; TA4-573	Capital Structure
Alaska Power Company	07/16	Alaska Power Company	Docket No. TA857-2	Rate of Return
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	01/20	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2021 Generic Cost of Capital, Proceeding ID. 24110	Rate of Return
Arizona Corporation Commission				
EPCOR Water Arizona, Inc.	06/20	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-20-0177	Rate of Return
Arizona Water Company	12/19	Arizona Water Company – Western Group	Docket No. W-01445A-19-0278	Rate of Return
Arizona Water Company	08/18	Arizona Water Company – Northern Group	Docket No. W-01445A-18-0164	Rate of Return
Colorado Public Utilities Commission				
Summit Utilities, Inc.	04/18	Colorado Natural Gas Company	Docket No. 18AL-0305G	Rate of Return
Atmos Energy Corporation	06/17	Atmos Energy Corporation	Docket No. 17AL-0429G	Rate of Return
Delaware Public Service Commission				
Delmarva Power & Light Co.	11/20	Delmarva Power & Light Co.	Docket No. 20-0149 (Electric)	Return on Equity
Delmarva Power & Light Co.	10/20	Delmarva Power & Light Co.	Docket No. 20-0150 (Gas)	Return on Equity
Tidewater Utilities, Inc.	11/13	Tidewater Utilities, Inc.	Docket No. 13-466	Capital Structure
Public Service Commission of the District of Columbia				
Washington Gas Light Company	09/20	Washington Gas Light Company	Formal Case No. 1162	Rate of Return
Federal Energy Regulatory Commission				
LS Power Grid California, LLC	10/20	LS Power Grid California, LLC	Docket No. ER21-195-000	Rate of Return
Florida Public Service Commission				
Tampa Electric Company	04/21	Tampa Electric Company	Docket No. 20210034-EI	Return on Equity
Peoples Gas System	09/20	Peoples Gas System	Docket No. 20200051-GU	Rate of Return
Utilities, Inc. of Florida	06/20	Utilities, Inc. of Florida	Docket No. 20200139-WS	Rate of Return
Hawaii Public Utilities Commission				
Launiupoko Irrigation Company, Inc.	12/20	Launiupoko Irrigation Company, Inc.	Docket No. 2020-0217 / Transferred to 2020-0089	Capital Structure
Lanai Water Company, Inc.	12/19	Lanai Water Company, Inc.	Docket No. 2019-0386	Cost of Service / Rate Design
Manele Water Resources, LLC	08/19	Manele Water Resources, LLC	Docket No. 2019-0311	Cost of Service / Rate Design
Kaupulehu Water Company	02/18	Kaupulehu Water Company	Docket No. 2016-0363	Rate of Return
Aqua Engineers, LLC	05/17	Puhi Sewer & Water Company	Docket No. 2017-0118	Cost of Service / Rate Design
Hawaii Resources, Inc.	09/16	Laie Water Company	Docket No. 2016-0229	Cost of Service / Rate Design
Illinois Commerce Commission				
Utility Services of Illinois, Inc.	02/21	Utility Services of Illinois, Inc.	Docket No. 21-0198	Rate of Return

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MANAGEMENT CONSULTANTS

Resume & Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Director

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Ameren Illinois Company d/b/a Ameren Illinois	07/20	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 20-0308	Return on Equity
Utility Services of Illinois, Inc.	11/17	Utility Services of Illinois, Inc.	Docket No. 17-1106	Cost of Service / Rate Design
Aqua Illinois, Inc.	04/17	Aqua Illinois, Inc.	Docket No. 17-0259	Rate of Return
Utility Services of Illinois, Inc.	04/15	Utility Services of Illinois, Inc.	Docket No. 14-0741	Rate of Return
Indiana Utility Regulatory Commission				
Aqua Indiana, Inc.	03/16	Aqua Indiana, Inc. Aboite Wastewater Division	Docket No. 44752	Rate of Return
Twin Lakes, Utilities, Inc.	08/13	Twin Lakes, Utilities, Inc.	Docket No. 44388	Rate of Return
Kansas Corporation Commission				
Atmos Energy	07/19	Atmos Energy	19-ATMG-525-RTS	Rate of Return
Kentucky Public Service Commission				
Bluegrass Water Utility Operating Company	10/20	Bluegrass Water Utility Operating Company	2020-00290	Return on Equity
Louisiana Public Service Commission				
Southwestern Electric Power Company	12/20	Southwestern Electric Power Company	Docket No. U-35441	Return on Equity
Atmos Energy	04/20	Atmos Energy	Docket No. U-35535	Rate of Return
Louisiana Water Service, Inc.	06/13	Louisiana Water Service, Inc.	Docket No. U-32848	Rate of Return
Maryland Public Service Commission				
Washington Gas Light Company	08/20	Washington Gas Light Company	Case No. 9651	Rate of Return
FirstEnergy, Inc.	08/18	Potomac Edison Company	Case No. 9490	Rate of Return
Massachusetts Department of Public Utilities				
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 19-130	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 19-131	Rate of Return
Liberty Utilities	07/15	Liberty Utilities d/b/a New England Natural Gas Company	Docket No. 15-75	Rate of Return
Minnesota Public Utilities Commission				
Northern States Power Company	11/20	Northern States Power Company	Docket No. E002/GR-20-723	Rate of Return
Mississippi Public Service Commission				
Atmos Energy	03/19	Atmos Energy	Docket No. 2015-UN-049	Capital Structure
Atmos Energy	07/18	Atmos Energy	Docket No. 2015-UN-049	Capital Structure
Missouri Public Service Commission				
Spire Missouri, Inc.	12/20	Spire Missouri, Inc.	Case No. GR-2021-0108	Return on Equity
Indian Hills Utility Operating Company, Inc.	10/17	Indian Hills Utility Operating Company, Inc.	Case No. SR-2017-0259	Rate of Return
Raccoon Creek Utility Operating Company, Inc.	09/16	Raccoon Creek Utility Operating Company, Inc.	Docket No. SR-2016-0202	Rate of Return
Public Utilities Commission of Nevada				
Southwest Gas Corporation	08/20	Southwest Gas Corporation	Docket No. 20-02023	Return on Equity
New Hampshire Public Utilities Commission				

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MANAGEMENT CONSULTANTS

Resume & Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Director

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Aquarion Water Company of New Hampshire, Inc.	12/20	Aquarion Water Company of New Hampshire, Inc.	Docket No. DW 20-184	Rate of Return
New Jersey Board of Public Utilities				
Atlantic City Electric Company	12/20	Atlantic City Electric Company	Docket No. ER20120746	Return on Equity
FirstEnergy	02/20	Jersey Central Power & Light Co.	Docket No. ER20020146	Rate of Return
Aqua New Jersey, Inc.	12/18	Aqua New Jersey, Inc.	Docket No. WR18121351	Rate of Return
Middlesex Water Company	10/17	Middlesex Water Company	Docket No. WR17101049	Rate of Return
Middlesex Water Company	03/15	Middlesex Water Company	Docket No. WR15030391	Rate of Return
The Atlantic City Sewerage Company	10/14	The Atlantic City Sewerage Company	Docket No. WR14101263	Cost of Service / Rate Design
Middlesex Water Company	11/13	Middlesex Water Company	Docket No. WR1311059	Capital Structure
New Mexico Public Regulation Commission				
Southwestern Public Service Company	01/21	Southwestern Public Service Company	Case No. 20-00238-UT	Return on Equity
North Carolina Utilities Commission				
Piedmont Natural Gas Co.Inc.	03/21	Piedmont Natural Gas Co., Inc.	Docket No. G-9, Sub 781	Return on Equity
Duke Energy Carolinas, LLC	07/20	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1214	Return on Equity
Duke Energy Progress, LLC	07/20	Duke Energy Progress, LLC	Docket No. E-2, Sub 1219	Return on Equity
Aqua North Carolina, Inc.	12/19	Aqua North Carolina, Inc.	Docket No. W-218 Sub 526	Rate of Return
Carolina Water Service, Inc.	06/19	Carolina Water Service, Inc.	Docket No. W-354 Sub 364	Rate of Return
Carolina Water Service, Inc.	09/18	Carolina Water Service, Inc.	Docket No. W-354 Sub 360	Rate of Return
Aqua North Carolina, Inc.	07/18	Aqua North Carolina, Inc.	Docket No. W-218 Sub 497	Rate of Return
North Dakota Public Service Commission				
Northern States Power Company	11/20	Northern States Power Company	Case No. PU-20-441	Rate of Return
Public Utilities Commission of Ohio				
Aqua Ohio, Inc.	05/16	Aqua Ohio, Inc.	Docket No. 16-0907-WW-AIR	Rate of Return
Pennsylvania Public Utility Commission				
Valley Energy, Inc.	07/19	C&T Enterprises	Docket No. R-2019-3008209	Rate of Return
Wellsboro Electric Company	07/19	C&T Enterprises	Docket No. R-2019-3008208	Rate of Return
Citizens' Electric Company of Lewisburg	07/19	C&T Enterprises	Docket No. R-2019-3008212	Rate of Return
Steelton Borough Authority	01/19	Steelton Borough Authority	Docket No. A-2019-3006880	Valuation
Mahoning Township, PA	08/18	Mahoning Township, PA	Docket No. A-2018-3003519	Valuation
SUEZ Water Pennsylvania Inc.	04/18	SUEZ Water Pennsylvania Inc.	Docket No. R-2018-000834	Rate of Return
Columbia Water Company	09/17	Columbia Water Company	Docket No. R-2017-2598203	Rate of Return
Veolia Energy Philadelphia, Inc.	06/17	Veolia Energy Philadelphia, Inc.	Docket No. R-2017-2593142	Rate of Return
Emporium Water Company	07/14	Emporium Water Company	Docket No. R-2014-2402324	Rate of Return
Columbia Water Company	07/13	Columbia Water Company	Docket No. R-2013-2360798	Rate of Return
Penn Estates Utilities, Inc.	12/11	Penn Estates, Utilities, Inc.	Docket No. R-2011-2255159	Capital Structure / Long-Term Debt Cost Rate

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MANAGEMENT CONSULTANTS

Resume & Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Director

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
South Carolina Public Service Commission				
Blue Granite Water Co.	12/19	Blue Granite Water Company	Docket No. 2019-292-WS	Rate of Return
Carolina Water Service, Inc.	02/18	Carolina Water Service, Inc.	Docket No. 2017-292-WS	Rate of Return
Carolina Water Service, Inc.	06/15	Carolina Water Service, Inc.	Docket No. 2015-199-WS	Rate of Return
Carolina Water Service, Inc.	11/13	Carolina Water Service, Inc.	Docket No. 2013-275-WS	Rate of Return
United Utility Companies, Inc.	09/13	United Utility Companies, Inc.	Docket No. 2013-199-WS	Rate of Return
Utility Services of South Carolina, Inc.	09/13	Utility Services of South Carolina, Inc.	Docket No. 2013-201-WS	Rate of Return
Tega Cay Water Services, Inc.	11/12	Tega Cay Water Services, Inc.	Docket No. 2012-177-WS	Capital Structure
Tennessee Public Utility Commission				
Piedmont Natural Gas Company	07/20	Piedmont Natural Gas Company	Docket No. 20-00086	Return on Equity
Public Utility Commission of Texas				
Southwestern Public Service Company	02/21	Southwestern Public Service Company	Docket No. 51802	Return on Equity
Southwestern Electric Power Company	10/20	Southwestern Electric Power Company	Docket No. 51415	Rate of Return
Virginia State Corporation Commission				
Virginia Natural Gas, Inc.	04/21	Virginia Natural Gas, Inc.	PUR-2020-00095	Return on Equity
Massanutten Public Service Corporation	12/20	Massanutten Public Service Corporation	PUE-2020-00039	Return on Equity
Aqua Virginia, Inc.	07/20	Aqua Virginia, Inc.	PUR-2020-00106	Rate of Return
WGL Holdings, Inc.	07/18	Washington Gas Light Company	PUR-2018-00080	Rate of Return
Atmos Energy Corporation	05/18	Atmos Energy Corporation	PUR-2018-00014	Rate of Return
Aqua Virginia, Inc.	07/17	Aqua Virginia, Inc.	PUR-2017-00082	Rate of Return
Massanutten Public Service Corp.	08/14	Massanutten Public Service Corp.	PUE-2014-00035	Rate of Return / Rate Design

Duke Energy Kentucky, Inc.
Table of Contents
Supporting Attachments Accompanying the Direct Testimony
of Dylan W. D'Ascendis, CRRA, CVA

Duke Energy Kentucky, Inc.
Recommended Capital Structure and Cost Rates
for Ratemaking Purposes
at March 31, 2021

Type Of Capital	Ratios (1)	Cost Rate	Weighted Cost Rate
Long-Term Debt	46.72%	3.84% (1)	1.80%
Short-Term Debt	2.58%	1.67% (1)	0.04%
Common Equity	50.70%	10.30% (2)	5.22%
Total	100.00%		7.06%

Notes:

(1) Company-provided.
(2) From page 2 of this Attachment.

Duke Energy Kentucky, Inc.
Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Proxy Group of Seven Natural Gas Distribution Companies
1.	Discounted Cash Flow Model (DCF) (1)	9.57%
2.	Risk Premium Model (RPM) (2)	10.65%
3.	Capital Asset Pricing Model (CAPM) (3)	11.62%
4.	Market Models Applied to Comparable Risk, Non-Price Regulated Companies (4)	12.27%
5.	Range of Common Equity Model Results	9.57% - 12.27%
6.	Size Risk Adjustment (5)	0.15%
7.	Credit Risk Adjustment (6)	0.14%
8.	Flotation Cost Adjustment (7)	0.12%
9.	Indicated Range of Common Equity Cost Rates after Adjustment	9.98% - 12.68%
10.	Recommended Common Equity Cost Rate	10.30%

Notes: (1) From page 1 of Attachment DWD-2.
(2) From page 1 of Attachment DWD-3.
(3) From page 1 of Attachment DWD-4.
(4) From page 1 of Attachment DWD-6.
(5) Adjustment to reflect the Company's greater business risk due to its smaller size relative to the Utility Proxy Group as detailed in Mr. D'Ascendis' direct testimony.
(6) Company-specific risk adjustment to reflect Duke Energy Kentucky' greater risk due to its Baa1 long-term issuer rating relative to the average A2/A3 long-term issuer rating of the Utility Proxy Group as detailed in Mr. D'Ascendis' Direct Testimony.

(7) From page 1 of Attachment DWD-8.

Duke Energy Kentucky, Inc.
Indicated Common Equity Cost Rate Using the Discounted Cash Flow Model for the
Proxy Group of Seven Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Seven Natural Gas Distribution Companies	Average Dividend Yield (1)	Value Line Projected Five Year Growth in EPS (2)	Zack's Five Year Projected Growth Rate in EPS	Bloomberg's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	Average Projected Five Year Growth in EPS (3)	Adjusted Dividend Yield (4)	Indicated Common Equity Cost Rate (5)
Atmos Energy Corporation	2.75 %	7.00 %	7.30 %	7.10 %	7.00 %	7.10 %	2.85 %	9.95 %
New Jersey Resources Corporation	3.48	1.50	6.00	7.73	6.00	5.31	3.57	8.88
Northwest Natural Holding Company	4.00	5.50	NA	5.00	3.10	4.53	4.09	8.62
ONE Gas, Inc.	3.18	6.50	5.00	5.67	5.00	5.54	3.27	8.81
South Jersey Industries, Inc.	5.10	10.50	4.40	2.68	4.40	5.50	5.24	10.74
Southwest Gas Holdings, Inc.	3.75	8.00	5.00	5.00	4.00	5.50	3.85	9.35
Spire Inc.	3.89	9.00	5.00	12.62	5.70	8.08	4.05	12.13
							Average	9.78 %
							Median	9.35 %
							Average of Mean and Median	9.57 %

NA= Not Available
NMF= Not Meaningful Figure

Notes:

(1) Indicated dividend at 03/31/2021 divided by the average closing price of the last 60 trading days ending 03/31/2021 for each company.
(2) From pages 2 through 8 of this Attachment.
(3) Average of columns 2 through 5 excluding negative growth rates.
(4) This reflects a growth rate component equal to one-half the conclusion of growth rate (from column 6) x column 1 to reflect the periodic payment of dividends (Gordon Model) as opposed to the continuous payment. Thus, for Atmos Energy Corporation, 2.75% x (1+(1/2 x 7.10%)) = 2.85%.
(5) Column 6 + column 7.

Source of Information:

Value Line Investment Survey
www.zacks.com Downloaded on 03/31/2021
www.yahoo.com Downloaded on 03/31/2021
Bloomberg Professional Services

ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE **91.05** | P/E RATIO **18.2** (Trailing: 18.3 / Median: 19.0) | RELATIVE P/E RATIO **0.85** | DIV'D YLD **2.9%** | VALUE LINE

TIMELINESS **2** Lowered 12/4/20
SAFETY **1** Raised 6/6/14
TECHNICAL **5** Lowered 2/26/21
BETA .80 (1.00 = Market)

High:	32.0	35.6	37.3	47.4	58.2	64.8	82.0	93.6	100.8	115.2	121.1	95.9
Low:	25.9	28.5	30.4	34.9	44.2	50.8	60.0	72.5	76.5	89.2	77.9	86.7

LEGENDS
— 0.50 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range
2024 | 2025 | 2026

18-Month Target Price Range
Low-High: $72-$160 — Midpoint (% to Mid): $116 (25%)

2024-26 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	160	(+75%)	17%
Low	130	(+45%)	12%

Institutional Decisions

	1Q2020	2Q2020	3Q2020
to Buy	268	233	256
to Sell	251	262	231
Hld's(000)	103070	108597	108898

% TOT. RETURN 1/21

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-22.6	26.6
3 yr.	14.1	29.4
5 yr.	43.0	99.1

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	© VALUE LINE PUB. LLC	24-26
61.75	75.27	66.03	79.52	53.69	53.12	48.15	38.10	42.88	49.22	40.82	32.23	26.01	28.00	24.32	22.41	**22.55**	**22.85**	Revenues per sh A	**35.50**
3.90	4.26	4.14	4.19	4.29	4.64	4.72	4.76	5.14	5.42	5.81	6.19	6.62	7.24	7.57	8.03	**8.40**	**8.85**	"Cash Flow" per sh	**10.25**
1.72	2.00	1.94	2.00	1.97	2.16	2.26	2.10	2.50	2.96	3.09	3.38	3.60	4.00	4.35	4.72	**5.00**	**5.35**	Earnings per sh AB	**6.50**
1.24	1.26	1.28	1.30	1.32	1.34	1.36	1.38	1.40	1.48	1.56	1.68	1.80	1.94	2.10	2.30	**2.50**	**2.70**	Div'ds Decl'd per sh C■	**3.30**
4.14	5.20	4.39	5.20	5.51	6.02	6.90	8.12	9.32	8.32	9.61	10.46	10.72	13.19	14.19	15.38	**15.80**	**15.75**	Cap'l Spending per sh	**15.15**
19.90	20.16	22.01	22.60	23.52	24.16	24.98	26.14	28.47	30.74	31.48	33.32	36.74	42.87	48.18	53.95	**61.35**	**69.20**	Book Value per sh	**87.85**
80.54	81.74	89.33	90.81	92.55	90.16	90.30	90.24	90.64	100.39	101.48	103.93	106.10	111.27	119.34	125.88	**133.00**	**137.00**	Common Shs Outst'g D	**155.00**
16.1	13.5	15.9	13.6	12.5	13.2	14.4	15.9	15.9	16.1	17.5	20.8	22.0	21.7	23.2	22.3	*Bold figures are*		Avg Ann'l P/E Ratio	**22.5**
.86	.73	.84	.82	.83	.84	.90	1.01	.89	.85	.88	1.09	1.11	1.17	1.24	1.13	*Value Line*		Relative P/E Ratio	**1.25**
4.5%	4.7%	4.2%	4.8%	5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	2.4%	2.3%	2.2%	2.1%	2.2%	*estimates*		Avg Ann'l Div'd Yield	**2.3%**
						4347.6	3438.5	3386.3	4940.9	4142.1	3349.9	2759.7	3115.5	2901.8	2821.1	**3000**	**3130**	Revenues ($mill) A	**5500**
						199.3	192.2	230.7	289.8	315.1	350.1	382.7	444.3	511.4	580.5	**660**	**725**	Net Profit ($mill)	**1000**
						36.4%	33.8%	38.2%	39.2%	38.3%	36.4%	36.6%	27.0%	21.4%	19.5%	**23.0%**	**23.0%**	Income Tax Rate	**25.0%**
						4.6%	5.6%	5.9%	5.9%	7.6%	10.5%	13.9%	14.3%	17.6%	20.6%	**22.0%**	**23.2%**	Net Profit Margin	**18.2%**
						49.4%	45.3%	48.8%	44.3%	43.5%	38.7%	44.0%	34.3%	38.0%	40.0%	**40.0%**	**40.0%**	Long-Term Debt Ratio	**40.0%**
						50.6%	54.7%	51.2%	55.7%	56.5%	61.3%	56.0%	65.7%	62.0%	60.0%	**60.0%**	**60.0%**	Common Equity Ratio	**60.0%**
						4461.5	4315.5	5036.1	5542.2	5650.2	5651.8	6965.7	7263.6	9279.7	11323	**13600**	**15800**	Total Capital ($mill)	**22700**
						5147.9	5475.6	6030.7	6725.9	7430.6	8280.5	9259.2	10371	11788	13355	**14500**	**15650**	Net Plant ($mill)	**19100**
						6.1%	6.1%	5.9%	6.4%	6.6%	7.2%	6.4%	6.9%	6.1%	5.5%	**6.0%**	**6.0%**	Return on Total Cap'l	**5.5%**
						8.8%	8.1%	8.9%	9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.6%	**8.0%**	**7.5%**	Return on Shr. Equity	**7.5%**
						8.8%	8.1%	8.9%	9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.6%	**8.0%**	**7.5%**	Return on Com Equity	**7.5%**
						3.3%	2.8%	4.0%	4.7%	4.9%	5.1%	4.9%	4.8%	4.6%	4.4%	**4.0%**	**4.0%**	Retained to Com Eq	**3.5%**
						62%	65%	56%	50%	51%	50%	50%	48%	48%	49%	**50%**	**51%**	All Div'ds to Net Prof	**51%**

CAPITAL STRUCTURE as of 12/31/20
Total Debt $5125.1 mill. **Due in 5 Yrs** $210.0 mill.
LT Debt $5124.9 mill. **LT Interest** $270.0 mill.
(LT interest earned: 9.5x; total interest coverage: 9.5x)
Leases, Uncapitalized Annual rentals $20.4 mill.

Pfd Stock None

Pension Assets-9/20 $528.9 mill.
Oblig. $604.2 mill.

Common Stock 128,160,695 shs.
as of 1/29/21

MARKET CAP: $11.7 billion (Large Cap)

CURRENT POSITION ($MILL.)	2019	2020	12/31/20
Cash Assets	24.5	20.8	457.6
Other	433.5	450.5	734.7
Current Assets	458.0	471.3	1192.3
Accts Payable	265.0	235.8	285.0
Debt Due	464.9	.2	.2
Other	479.5	546.4	512.6
Current Liab.	1209.4	782.4	797.8
Fix. Chg. Cov.	990%	1306%	1315%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '24-'26
Revenues	-8.5%	-11.0%	6.0%
"Cash Flow"	5.5%	7.0%	5.0%
Earnings	8.0%	9.0%	7.0%
Dividends	5.0%	7.5%	7.5%
Book Value	7.5%	10.0%	10.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2018	889.2	1219.4	562.2	444.7	3115.5
2019	877.8	1094.6	485.7	443.7	2901.8
2020	875.6	977.6	493.0	474.9	2821.1
2021	914.5	**1060**	**525**	**500.5**	**3000**
2022	**960**	**1105**	**545**	**520**	**3130**

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2018	1.40	1.57	.64	.41	4.00
2019	1.38	1.82	.68	.49	4.35
2020	1.47	1.95	.79	.53	4.72
2021	1.71	**1.99**	**.78**	**.52**	**5.00**
2022	**1.82**	**2.07**	**.85**	**.61**	**5.35**

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.45	.45	.45	.485	1.84
2018	.485	.485	.485	.525	1.98
2019	.525	.525	.525	.575	2.15
2020	.575	.575	.575	.625	2.35
2021	.625				

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2020: 68.6%, residential; 26.2%, commercial; 3.6%, industrial; and 1.6% other. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately 1.4% of common stock (12/19 Proxy). President and Chief Executive Officer: Kevin Akers. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy got off to a great start in fiscal 2021 (ends September 30th). Indeed, first-quarter share net of $1.71 was around 16% above the year-ago tally of $1.47. That was made possible partly by the natural gas distribution unit, which benefited from higher rates, mainly in the Mid-Tex, Mississippi, Louisiana, and West Texas divisions. Customer growth, primarily in the Mid-Tex unit, and a decline in operating expenses also helped. Elsewhere, results of the pipeline and storage business received a boost from a GRIP filing approved in May, 2020 plus lower system maintenance costs. Assuming no major COVID-19-related disruptions, consolidated share net may advance around 6%, to $5.00, relative to last year's $4.72 tally. Concerning fiscal 2022, we expect the bottom line to rise at a similar percentage rate, to $5.35 a share, as operating margins widen further.

This year's capital expenditures are expected to be between $2 billion and $2.2 billion. This would be about 8.5% higher than the fiscal 2020 figure if the midpoint of that range is used. Similar to prior periods, a meaningful portion of the resources are being deployed to enhance the safety and reliability of Atmos' natural gas distribution and transmission systems. We believe that the fiscal 2022 capital spending budget will be a bit above the present level.

***Value Line* is optimistic about the company's performance out to 2024-2026.** It ranks as one of the nation's biggest natural gas-only distributors, boasting more than three million customers across several states, including Texas, Louisiana, and Mississippi. Moreover, we think the pipeline and storage unit has healthy overall growth prospects, since it operates in one of the most-active drilling regions in the world. Lastly, the balance sheet is in solid condition. In Atmos' current configuration, annual earnings increases might be between 6% and 8% over the 3- to 5-year period.

The high-quality stock has some appealing attributes. Among them is the 2 (Above Average) Timeliness rank. Consider, also, the total return possibilities through mid-decade. Another plus is the shares' 18-month capital gains potential.

Frederick L. Harris, III February 26, 2021

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. gains (loss): '10, 5¢; '11, (1¢); '18, $1.43; '20, 17¢. Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢; '17, 13¢. Next egs. rpt. due early May.
(C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail.
(D) In millions.
(E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	95
Earnings Predictability	100

NEW JERSEY RES. NYSE-NJR

RECENT PRICE 36.62 | P/E RATIO 22.2 (Trailing: 18.6, Median: 17.0) | RELATIVE P/E RATIO 1.04 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 5 Lowered 12/25/20
SAFETY 2 Lowered 4/17/20
TECHNICAL 5 Lowered 2/19/21
BETA .95 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$25-$61 $43 (15%)

2024-26 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+35%)	11%
Low	35	(-5%)	3%

Institutional Decisions

	1Q2020	2Q2020	3Q2020
to Buy	123	139	129
to Sell	131	97	105
Hld's(000)	67063	67573	69155

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
High:	22.0	25.2	25.1	23.8	32.1	34.1	38.9	45.4	51.8	51.2	44.7	38.4
Low:	16.7	19.8	19.3	19.5	21.9	26.8	30.5	33.7	35.6	40.3	21.1	33.3

Target Price Range
2024 2025 2026

% TOT. RETURN 1/21

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-11.5	26.6
3 yr.	-0.9	29.4
5 yr.	15.2	99.1

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	© VALUE LINE PUB. LLC	24-26
38.10	39.81	36.31	45.37	31.17	32.05	36.30	27.08	38.38	44.40	32.09	21.90	26.28	33.24	29.01	20.39	*23.70*	*25.50*	Revenues per sh A	*27.30*
1.31	1.37	1.22	1.81	1.58	1.63	1.70	1.86	1.93	2.73	2.52	2.46	2.68	3.72	2.99	3.30	*2.95*	*3.60*	"Cash Flow" per sh	*3.90*
.88	.93	.78	1.35	1.20	1.23	1.29	1.36	1.37	2.08	1.78	1.61	1.73	2.72	1.96	2.07	*1.65*	*2.25*	Earnings per sh B	*2.45*
.45	.48	.51	.56	.62	.68	.72	.77	.81	.86	.93	.98	1.04	1.11	1.19	1.27	*1.34*	*1.42*	Div'ds Decl'd per sh C■	*1.65*
.64	.64	.73	.86	.90	1.05	1.13	1.26	1.33	1.52	3.76	4.15	3.80	4.39	5.83	4.68	*4.10*	*4.10*	Cap'l Spending per sh	*4.00*
5.30	7.50	7.75	8.64	8.29	8.81	9.36	9.80	10.65	11.48	12.99	13.58	14.33	16.18	17.37	19.26	*19.80*	*20.85*	Book Value per sh D	*23.60*
82.64	82.88	83.22	84.12	83.17	82.35	82.89	83.05	83.32	84.20	85.19	85.88	86.32	87.69	89.34	95.80	*97.00*	*98.00*	Common Shs Outst'g E	*100.00*
16.8	16.1	21.6	12.3	14.9	15.0	16.8	16.8	16.0	11.7	16.6	21.3	22.4	15.6	24.3	17.7	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.89	.87	1.15	.74	.99	.95	1.05	1.07	.90	.62	.84	1.12	1.13	.84	1.29	.92	*Value Line*		Relative P/E Ratio	*.95*
3.1%	3.2%	3.0%	3.3%	3.5%	3.7%	3.3%	3.4%	3.7%	3.5%	3.1%	2.9%	2.7%	2.6%	2.5%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 12/31/20
Total Debt $2426.1 mill. **Due in 5 Yrs** $420.5 mill.
LT Debt $2264.9 mill. **LT Interest** $47.1 mill.
Incl. $54.9 mill. capitalized leases.
(LT interest earned: 5.0x; total interest coverage: 5.0x)

Pension Assets-9/20 $404.4 mill. **Oblig.** $643.0 mill.

Pfd Stock None

Common Stock 96,250,435 shs.
as of 2/2/21
MARKET CAP: $3.5 billion (Mid Cap)

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		24-26
3009.2	2248.9	3198.1	3738.1	2734.0	1880.9	2268.6	2915.1	2592.0	1953.7	*2300*	*2500*	Revenues ($mill) A	*2730*
106.5	112.4	113.7	176.9	153.7	138.1	149.4	240.5	175.0	196.3	*160*	*220*	Net Profit ($mill)	*245*
30.2%	7.1%	25.4%	30.2%	26.3%	15.5%	17.2%	- -	NMF	*5.0%*	*5.0%*	*5.0%*	Income Tax Rate	*5.0%*
3.5%	5.0%	3.6%	4.7%	5.6%	7.3%	6.6%	8.2%	6.7%	10.0%	*7.0%*	*8.8%*	Net Profit Margin	*9.0%*
35.5%	39.2%	36.6%	38.2%	43.2%	47.7%	44.6%	45.4%	49.8%	55.1%	*54.5%*	*55.0%*	Long-Term Debt Ratio	*54.5%*
64.5%	60.8%	63.4%	61.8%	56.8%	52.3%	55.4%	54.6%	50.2%	44.9%	*45.5%*	*45.0%*	Common Equity Ratio	*45.5%*
1203.1	1339.0	1400.3	1564.4	1950.6	2230.1	2233.7	2599.6	3088.9	4104.2	*4220*	*4545*	Total Capital ($mill)	*5160*
1295.9	1484.9	1643.1	1884.1	2128.3	2407.7	2609.7	2651.0	3041.2	3983.0	*4065*	*4145*	Net Plant ($mill)	*4400*
9.7%	9.2%	9.0%	12.1%	8.6%	6.9%	7.7%	10.1%	6.4%	5.6%	*5.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
13.7%	13.8%	12.8%	18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	*8.5%*	*11.0%*	Return on Shr. Equity	*10.5%*
13.7%	13.8%	12.8%	18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	*10.6%*	*8.5%*	*11.0%*	Return on Com Equity	*10.5%*
6.2%	6.2%	5.2%	11.0%	7.0%	4.8%	5.0%	10.2%	4.6%	4.2%	*1.5%*	*4.0%*	Retained to Com Eq	*3.5%*
55%	55%	59%	40%	50%	60%	59%	40%	59%	60%	*81%*	*63%*	All Div'ds to Net Prof	*67%*

CURRENT POSITION ($MILL.)	2019	2020	12/31/20
Cash Assets	2.7	117.0	22.4
Other	508.9	505.3	586.8
Current Assets	511.6	622.3	609.2
Accts Payable	295.9	270.1	263.4
Debt Due	46.9	152.6	161.2
Other	103.6	111.0	94.1
Current Liab.	446.4	533.7	518.7
Fix. Chg. Cov.	545%	545%	550%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '24-'26
Revenues	-2.5%	-4.0%	*NMF*
"Cash Flow"	7.5%	7.5%	*2.5%*
Earnings	7.0%	6.0%	*1.5%*
Dividends	7.0%	6.5%	*5.5%*
Book Value	7.0%	8.5%	*5.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2018	705.3	1019.1	543.4	647.3	2915.1
2019	811.8	866.2	434.9	479.1	2592.0
2020	615.0	639.6	299.0	400.1	1953.7
2021	454.3	*725*	*505*	*615.7*	*2300*
2022	*505*	*775*	*555*	*665*	*2500*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2018	1.53	1.61	d.09	d.33	2.72
2019	.61	1.27	d.20	.29	1.96
2020	.44	1.12	d.06	.57	2.07
2021	.46	*.90*	*d.15*	*.44*	*1.65*
2022	*.49*	*1.17*	*d.03*	*.62*	*2.25*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.255	.255	.255	.273	1.04
2018	.273	.273	.273	.2925	1.11
2019	.2925	.2925	.2925	.3125	1.19
2020	.3125	.3125	.3125	.3325	1.27
2021	.3325				

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in NJ, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had 558,000 cust. at 9/30/20. Fiscal 2020 volume: 215 bill. cu. ft. (14% interruptible, 21% res., 10% commercial & elec. utility, 55% capacity release programs). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2020 dep. rate: 2.8%. Has 1,156 empls. Off./dir. own 1.3% of common; BlackRock, 14.3%; Vanguard, 10.6% (12/20 Proxy). CEO, President & Director: Steven D. Westhoven. Incorporated: New Jersey. Address: 1415 Wyckoff Road, Wall, NJ 07719. Telephone: 732-938-1480. Web: www.njresources.com.

New Jersey Resources is off to a so-so start in fiscal 2021 (year ends September 30th). On the downside, the December-quarter revenues fell 26.1%, to $454.3 million, due to double-digit volume declines at the nonutility and utility divisions, as the coronavirus pandemic continues to weigh on end-use consumer demand. Meanwhile, on the profitability front, total expenses declined about 740 basis points, when viewed as a percentage of the top line. All told, these factors drove the bottom line roughly 4.5% higher, to $0.46 a share. This was markedly below our call for earnings of $0.55.

We have reduced our annual top- and bottom-line estimates by $450 million, and $0.60, to $2.3 billion and $1.65 a share, respectively. Our revised figure would represent a more-than-15% year-over-year decline, as overall system throughput will likely be depressed in the near term. Additionally, although commodity prices have rebounded from the lows experienced in early 2020, fossil fuel prices are still down when viewed against historical levels. We look for the company to continue to face a challenging operating environment this year, until vaccines can be widely distributed and the economy returns to pre-pandemic levels. Meanwhile, we are introducing our fiscal 2022 revenue and earnings estimates at $2.5 billion, and $2.25 a share, respectively. New accounts at the NJNG regulated utility segment and economic recovery should be the primary drivers here.

The balance sheet is in decent shape at the moment. Although cash reserves declined roughly 80% over the first quarter of this year, that cushion still sat at $22.4 million. Too, the long-term debt load remained stable at $2.265 billion, or 57% of total capital. This is relatively standard for a utility. Finally, the somewhat recent increase to the quarterly dividend leaves NJR with a competitive yield.

At this juncture, we think most investors' funds could be better utilized elsewhere. The stock is trading near the low end of our 3- to 5-year Target Price Range, suggesting limited upside potential. And, since our November review, NJR fell one notch in Timeliness, to 5 (Lowest), for year-ahead performance.

Bryan J. Fong *February 26, 2021*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly. sales and egs. may not sum to total due to rounding and change in shares outstanding. Next earnings report due early May.
(C) Dividends historically paid in early Jan., April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2020: $527.5 million, $5.51/share.
(E) In millions, adjusted for splits.

Company's Financial Strength	A+
Stock's Price Stability	80
Price Growth Persistence	60
Earnings Predictability	50

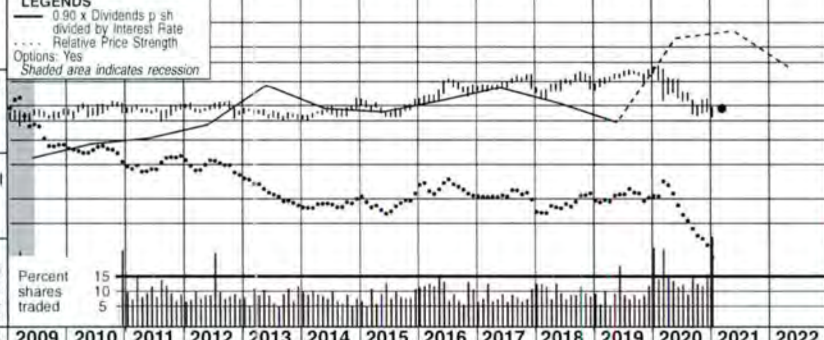
N.W. NATURAL NYSE-NWN

RECENT PRICE **46.32** | P/E RATIO **18.9** (Trailing: 22.5 / Median: 23.0) | RELATIVE P/E RATIO **0.89** | DIV'D YLD **4.1%** | VALUE LINE

TIMELINESS 3 Raised 11/20/20
SAFETY 1 Raised 3/18/05
TECHNICAL 5 Lowered 2/12/21
BETA .80 (1.00 = Market)

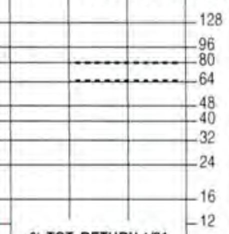
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
High:	50.9	49.0	50.8	46.6	52.6	52.3	66.2	69.5	71.8	74.1	77.3	47.5
Low:	41.1	39.6	41.0	40.0	40.1	42.0	48.9	56.5	51.5	57.2	42.3	41.7

LEGENDS
— 0.90 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range

2024	2025	2026



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$37-$97	$67 (45%)

2024-26 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+75%)	18%
Low	65	(+40%)	12%

Institutional Decisions

	1Q2020	2Q2020	3Q2020
to Buy	88	73	92
to Sell	133	103	94
Hld's(000)	22679	21936	21896

% TOT. RETURN 1/21

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-33.9	26.6
3 yr.	-11.1	29.4
5 yr.	4.6	99.1

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	© VALUE LINE PUB. LLC	24-26
33.01	37.20	39.13	39.16	38.17	30.56	31.72	27.14	28.02	27.64	26.39	23.61	26.52	24.45	24.49	**24.65**	**26.45**	**27.70**	Revenues per sh	**31.05**
4.34	4.76	5.41	5.31	5.20	5.18	5.00	4.94	5.04	5.05	4.91	4.93	1.04	5.28	5.15	**5.30**	**5.15**	**6.05**	"Cash Flow" per sh	**6.85**
2.11	2.35	2.76	2.57	2.83	2.73	2.39	2.22	2.24	2.16	1.96	2.12	d1.94	2.33	2.19	**2.25**	**2.50**	**2.65**	Earnings per sh A	**3.10**
1.32	1.39	1.44	1.52	1.60	1.68	1.75	1.79	1.83	1.85	1.86	1.87	1.88	1.89	1.90	1.91	**1.92**	**1.93**	Div'ds Decl'd per sh B ■	**1.96**
3.48	3.56	4.48	3.92	5.09	9.35	3.76	4.91	5.13	4.40	4.37	4.87	7.43	7.43	7.95	**8.05**	**8.40**	**8.70**	Cap'l Spending per sh	**9.40**
21.28	22.01	22.52	23.71	24.88	26.08	26.70	27.23	27.77	28.12	28.47	29.71	25.85	26.41	28.42	**30.65**	**33.85**	**37.10**	Book Value per sh D	**45.30**
27.58	27.24	26.41	26.50	26.53	26.58	26.76	26.92	27.08	27.28	27.43	28.63	28.74	28.88	30.47	**31.00**	**31.00**	**31.00**	Common Shs Outst'g C	**32.00**
17.0	15.9	16.7	18.1	15.2	17.0	19.0	21.1	19.4	20.7	23.7	26.9	--	26.6	30.9	**25.5**	*Bold figures are*		Avg Ann'l P/E Ratio	**24.0**
.91	.86	.89	1.09	1.01	1.08	1.19	1.34	1.09	1.09	1.19	1.41	--	1.44	1.65	**1.33**	*Value Line*		Relative P/E Ratio	**1.35**
3.7%	3.7%	3.1%	3.3%	3.7%	3.6%	3.9%	3.8%	4.2%	4.1%	4.0%	3.3%	3.0%	3.0%	2.8%	3.3%	*estimates*		Avg Ann'l Div'd Yield	**2.6%**

CAPITAL STRUCTURE as of 9/30/20
Total Debt $1178.4 mill. **Due in 5 Yrs** $910.0 mill.
LT Debt $860.2 mill. **LT Interest** $40.0 mill.

(Total interest coverage: 3.1x)

Pension Assets-12/19 $313.1 mill. **Oblig.** $515.7 mill.

Pfd Stock None

Common Stock 30,568,578 shares
as of 10/29/20

MARKET CAP $1.4 billion (Mid Cap)

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		24-26
848.8	730.6	758.5	754.0	723.8	676.0	762.2	706.1	746.4	**765**	**820**	**860**	Revenues ($mill)	**995**
63.9	59.9	60.5	58.7	53.7	58.9	d55.6	67.3	65.3	**70.0**	**75.0**	**80.0**	Net Profit ($mill)	**100**
40.4%	42.4%	40.8%	41.5%	40.0%	40.9%	--	26.4%	16.2%	**21.0%**	**21.0%**	**21.0%**	Income Tax Rate	**21.0%**
7.5%	8.2%	8.0%	7.8%	7.4%	8.7%	NMF	9.5%	8.8%	**9.2%**	**9.1%**	**9.3%**	Net Profit Margin	**10.1%**
47.3%	48.5%	47.6%	44.8%	42.5%	44.4%	47.9%	48.1%	48.2%	**48.5%**	**49.0%**	**46.5%**	Long-Term Debt Ratio	**43.0%**
52.7%	51.5%	52.4%	55.2%	57.5%	55.6%	52.1%	51.9%	51.8%	**51.5%**	**51.0%**	**53.5%**	Common Equity Ratio	**57.0%**
1356.2	1424.7	1433.6	1389.0	1357.7	1529.8	1426.0	1468.9	1672.0	**1850**	**2050**	**2150**	Total Capital ($mill)	**2550**
1893.9	1973.6	2062.9	2121.6	2182.7	2260.9	2255.0	2421.4	2438.9	**2535**	**2640**	**2750**	Net Plant ($mill)	**3105**
6.2%	5.7%	5.8%	5.8%	5.5%	5.1%	NMF	5.8%	5.2%	**3.8%**	**4.0%**	**4.0%**	Return on Total Cap'l	**4.0%**
8.9%	8.2%	8.1%	7.6%	6.9%	6.9%	NMF	8.8%	7.5%	**7.5%**	**7.5%**	**7.0%**	Return on Shr. Equity	**7.0%**
8.9%	8.2%	8.1%	7.6%	6.9%	6.9%	NMF	8.8%	7.5%	**7.5%**	**7.5%**	**7.0%**	Return on Com Equity	**7.0%**
2.4%	1.6%	1.5%	1.1%	.6%	.9%	NMF	2.1%	1.4%	**1.0%**	**1.5%**	**2.0%**	Retained to Com Eq	**2.5%**
73%	80%	81%	85%	92%	87%	NMF	76%	82%	**85%**	**77%**	**73%**	All Div'ds to Net Prof	**64%**

CURRENT POSITION ($MILL.)	2018	2019	9/30/20
Cash Assets	12.6	9.6	35.9
Other	283.3	284.1	206.9
Current Assets	295.9	293.7	242.8
Accts Payable	115.9	113.4	83.8
Debt Due	247.6	224.2	318.2
Other	145.6	144.6	149.3
Current Liab.	509.1	482.2	551.3
Fix. Chg. Cov.	357%	336%	312%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '24-'26
Revenues	-4.0%	-2.0%	4.0%
"Cash Flow"	-3.0%	-5.5%	4.5%
Earnings	-11.0%	-17.0%	5.5%
Dividends	2.0%	0.5%	.5%
Book Value	1.5%	-0.5%	8.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	264.7	124.6	91.2	226.7	706.1
2019	285.4	123.4	90.3	247.3	746.4
2020	285.2	135.0	93.3	**251.5**	**765**
2021	**305**	**145**	**110**	**260**	**820**
2022	**315**	**155**	**120**	**270**	**860**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	1.46	d.01	d.39	1.27	2.33
2019	1.50	.07	d.61	1.26	2.19
2020	1.58	d.17	d.61	**1.45**	**2.25**
2021	**1.60**	**d.10**	**d.50**	**1.50**	**2.50**
2022	**1.64**	**d.06**	**d.47**	**1.54**	**2.65**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.47	.47	.47	.4725	1.88
2018	.4725	.4725	.4725	.475	1.89
2019	.475	.475	.475	.4775	1.90
2020	.4775	.4775	.4775	.48	1.91
2021	.48				

BUSINESS: Northwest Natural Holding Co. distributes natural gas to 1000 communities, 750,000 customers, in Oregon (89% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 3.7 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 37%; commercial, 22%; industrial, gas transportation, 41%. Employs 1,167. BlackRock Inc. owns 15.5% of shares; Off./Dir. own less than 1% (4/20 proxy). CEO: David H. Anderson. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural Holding Co. likely performed fairly well last year. (Note: The company was expected to issue its annual results shortly after this report went to press.) We look for revenues and earnings to advance approximately 2.5%, to $765 million and $2.25 a share, respectively. Despite the challenging operating environment and economic headwinds provided by the COVID-19 pandemic, Northwest Natural added more than 14,000 new natural gas meters over the past 12 months. Additional benefits stemmed from the Oregon Public Utility Commission's approval of a $45 million rate increase.

We look for the company's momentum to improve this year. The utility services provider appears well positioned to register revenue growth of more than 7% this year, to $820 million. New customer accounts, rate increases, and acquisitions augur well for overall business operations. In fact, the NW Natural Water company recently purchased Suncadia water and wastewater utilities, the T&W water utility, and multiple systems in Idaho. Assuming costs associated with the pandemic begin to subside, we look for continued margin expansion as the year progresses. On balance, NWN's annual earnings may well advance 11% this year, to $2.50 per share. Finally, we are introducing our 2022 top- and bottom-line estimates at $860 million and $2.65 a share, respectively.

The natural gas distributor's balance sheet is in good shape and improving. At the end of the third quarter, the last period for which financial information was available, cash reserves had swelled 272%, to $35.9 million. Meanwhile, the long-term debt load increased 6.7%, to $860 million. This represents a relatively modest 50% of total capital, when viewed against the industry as a whole.

These shares may appeal to patient investors with an eye on income generation. NWN offers better-than-average appreciation potential for the pull to 2024-2026. What's more, the recent hike in the quarterly dividend, to $0.48 per share, brings the yield to over 4%, handily besting the *Value Line* median. Finally, our Timeliness Ranking System suggests these shares will keep pace with the broader market averages in the coming year.

Bryan J. Fong — *February 26, 2021*

(A) Diluted earnings per share. Excludes nonrecurring items: '06, ($0.06); '08, ($0.03); '09, $0.06; May not sum due to rounding. Next earnings report due in early May.

(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.

(D) Includes intangibles. In 2019: $343.2 million, $11.26/share.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	35
Earnings Predictability	5

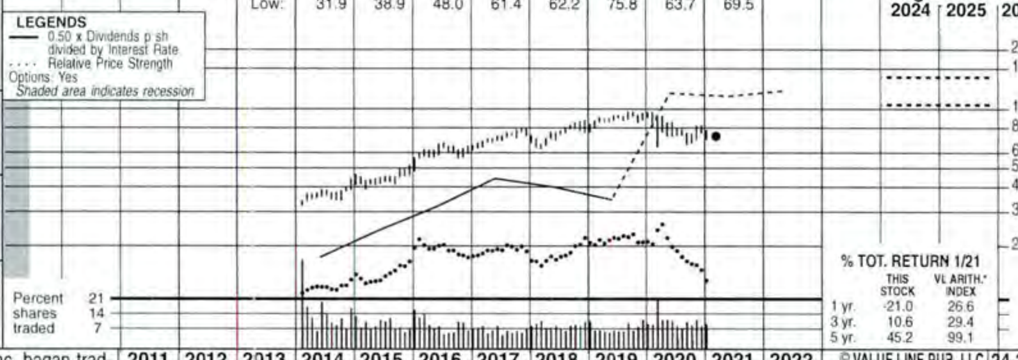
ONE GAS, INC. NYSE-OGS

RECENT PRICE 72.69 | P/E RATIO 19.1 (Trailing: 20.5 Median: NMF) | RELATIVE P/E RATIO 0.90 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS 4 Lowered 11/20/20
SAFETY 2 New 6/2/17
TECHNICAL 4 Lowered 2/12/21
BETA .80 (1.00 = Market)

	2014	2015	2016	2017	2018	2019	2020	2021
High:	44.3	51.8	67.4	79.5	87.8	96.7	97.0	78.0
Low:	31.9	38.9	48.0	61.4	62.2	75.8	63.7	69.5

LEGENDS
— 0.50 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2024 2025 2026

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$59-$131	$95 (30%)

2024-26 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	145	(+100%)	21%
Low	105	(+45%)	12%

Institutional Decisions

	1Q2020	2Q2020	3Q2020
to Buy	124	142	130
to Sell	157	137	151
Hld's(000)	41769	42060	42057

Percent shares traded 21 14 7

% TOT. RETURN 1/21

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-21.0	26.6
3 yr.	10.6	29.4
5 yr.	45.2	99.1

The shares of ONE Gas, Inc. began trading "regular-way" on the New York Stock Exchange on February 3, 2014. That happened as a result of the separation of ONEOK's natural gas distribution operation. Regarding the details of the spinoff, on January 31, 2014, ONEOK distributed one share of OGS common stock for every four shares of ONEOK common stock held by ONEOK shareholders of record as of the close of business on January 21. It should be mentioned that ONEOK did not retain any ownership interest in the new company.

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	© VALUE LINE PUB. LLC	24-26
--	--	--	34.92	29.62	27.30	29.43	31.08	31.32	**28.30**	**30.20**	**31.95**	Revenues per sh	**40.35**
--	--	--	4.52	4.82	5.43	5.96	6.32	6.96	**7.30**	**7.70**	**8.10**	"Cash Flow" per sh	**9.65**
--	--	--	2.07	2.24	2.65	3.02	3.25	3.51	**3.68**	**3.80**	**4.00**	Earnings per sh A	**5.00**
--	--	--	.84	1.20	1.40	1.68	1.84	2.00	2.16	**2.32**	**2.48**	Div'ds Decl'd per sh B■	**2.95**
--	--	--	5.70	5.63	5.91	6.81	7.50	7.91	**8.80**	**8.95**	**9.15**	Cap'l Spending per sh	**9.50**
--	--	--	34.45	35.24	36.12	37.47	38.86	40.35	**42.70**	**45.80**	**47.90**	Book Value per sh	**53.70**
--	--	--	52.08	52.26	52.28	52.31	52.57	52.77	**53.00**	**53.50**	**53.50**	Common Shs Outst'g C	**57.00**
--	--	--	17.8	19.8	22.7	23.5	23.1	25.3	**22.4**	*Bold figures are*	*Value Line estimates*	Avg Ann'l P/E Ratio	**25.0**
--	--	--	.94	1.00	1.19	1.18	1.25	1.35	**1.15**			Relative P/E Ratio	**1.40**
--	--	--	2.3%	2.7%	2.3%	2.4%	2.5%	2.3%	2.7%			Avg Ann'l Div'd Yield	**2.4%**
--	--	--	1818.9	1547.7	1427.2	1539.6	1633.7	1652.7	**1500**	**1615**	**1710**	Revenues ($mill)	**2300**
--	--	--	109.8	119.0	140.1	159.9	172.2	186.7	**195**	**205**	**215**	Net Profit ($mill)	**285**
--	--	--	38.4%	38.0%	37.8%	36.4%	23.7%	18.7%	**18.0%**	**18.5%**	**18.5%**	Income Tax Rate	**22.0%**
--	--	--	6.0%	7.7%	9.8%	10.4%	10.5%	11.3%	**13.0%**	**12.7%**	**12.6%**	Net Profit Margin	**12.4%**
--	--	--	40.1%	39.5%	38.7%	37.8%	38.6%	37.7%	**42.0%**	**40.0%**	**40.0%**	Long-Term Debt Ratio	**40.0%**
--	--	--	59.9%	60.5%	61.3%	62.2%	61.4%	62.3%	**58.0%**	**60.0%**	**60.0%**	Common Equity Ratio	**60.0%**
--	--	--	2995.3	3042.9	3080.7	3153.5	3328.1	3415.5	**3900**	**4085**	**4270**	Total Capital ($mill)	**5100**
--	--	--	3293.7	3511.9	3731.6	4007.6	4283.7	4565.2	**4830**	**5060**	**5290**	Net Plant ($mill)	**5750**
--	--	--	4.4%	4.7%	5.2%	5.8%	5.9%	6.4%	**6.5%**	**6.5%**	**6.0%**	Return on Total Cap'l	**7.0%**
--	--	--	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	**8.5%**	**8.5%**	**8.5%**	Return on Shr. Equity	**9.5%**
--	--	--	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	**8.5%**	**8.5%**	**8.5%**	Return on Com Equity	**9.5%**
--	--	--	3.7%	3.1%	3.5%	3.7%	3.7%	3.8%	**3.5%**	**3.5%**	**3.0%**	Retained to Com Eq	**4.0%**
--	--	--	40%	53%	52%	55%	56%	56%	**59%**	**61%**	**62%**	All Div'ds to Net Prof	**59%**

CAPITAL STRUCTURE as of 9/30/20
Total Debt $1890.2 mill. **Due in 5 Yrs** $1150.0 mill.
LT Debt $1582.2 mill. **LT Interest** $85.0 mill.
(LT interest earned: 4.7x; total interest coverage: 4.7x)
Leases, Uncapitalized Annual rentals $7.6 mill.
Pfd Stock None
Pension Assets-12/19 $908.0 mill. **Oblig.** $1001.4 mill.
Common Stock 53,096,893 shs. **as of 10/26/20**
MARKET CAP: $3.9 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2018	2019	9/30/20
Cash Assets	21.3	17.9	6.2
Other	522.0	488.3	363.5
Current Assets	543.3	506.2	369.7
Accts Payable	174.5	120.5	65.3
Debt Due	299.5	516.5	308.0
Other	224.9	235.7	202.4
Current Liab.	698.9	872.7	575.7
Fix. Chg. Cov.	677%	567%	563%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '24-'26
Revenues	--	-2.5%	4.0%
"Cash Flow"	--	7.0%	6.0%
Earnings	--	9.5%	6.5%
Dividends	--	17.0%	7.0%
Book Value	--	2.5%	4.5%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	638.5	292.5	238.3	464.4	1633.7
2019	661.0	290.6	248.6	452.5	1652.7
2020	528.2	273.3	244.6	**453.9**	**1500**
2021	**590**	**310**	**255**	**460**	**1615**
2022	**625**	**330**	**275**	**480**	**1710**

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	1.72	.39	.31	.83	3.25
2019	1.76	.46	.33	.96	3.51
2020	1.72	.48	.39	**1.09**	**3.68**
2021	**1.80**	**.50**	**.42**	**1.08**	**3.80**
2022	**1.85**	**.55**	**.47**	**1.13**	**4.00**

Calendar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.42	.42	.42	.42	1.68
2018	.46	.46	.46	.46	1.84
2019	.50	.50	.50	.50	2.00
2020	.54	.54	.54	.54	2.16
2021	.58				

BUSINESS: ONE Gas, Inc. provides natural gas distribution services to more than two million customers. There are three divisions: Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service. The company purchased 174 Bcf of natural gas supply in 2019, compared to 180 Bcf in 2018. Total volumes delivered by customer (fiscal 2019): transportation, 56.6%; residential, 32.5%; commercial & industrial, 10.3%; other, .6%. ONE Gas has around 3,600 employees. BlackRock owns 12.1% of common stock; The Vanguard Group, 10.1%; T. Rowe Price Associates, 7.0%; officers and directors, 1.9% (4/20 Proxy). CEO: Pierce H. Norton II. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Tel.: 918-947-7000. Internet: www.onegas.com.

Earnings for ONE Gas ought to be a bit higher in 2021. (Last year's fourth-quarter figures were expected to come out shortly after this report went to press.) This improvement should be made possible partly by the benefit of new rates. Other positives include an expanding customer base and a subdued effective income tax rate. Depreciation & amortization expense stands to increase some, but this ought to reflect necessary capital investments. Assuming no big COVID-19-related problems, the bottom line may grow around 3%, to $3.80 a share, versus our 2020 estimate of $3.68. Turning to 2022, share net might rise another 5%, to $4.00, as operating margins widen further.

Leadership states that it looks for this year's capital expenditures, including asset removal costs, to be around $540 million. (That would be above 2020's anticipated range of $500 million to $525 million.) Roughly 70% of the budget is dedicated to system integrity and pipeline replacement projects. Notably, the company projects total spending to be $3 billion (or $540 million—$640 million annually) between 2021 and 2025, with roughly the same percentage of capital allocated to where it is at present.

Prospects out to 2024-2026 appear encouraging. ONE Gas ranks as the leading natural gas distributor (as measured by customer count) in both Oklahoma and Kansas, and holds the number-three position in Texas. Moreover, these markets seem to have decent growth possibilities and are located in one of the most active drilling regions in the United States. Also, with healthy finances, the company ought to be able to satisfy its working capital requirements, capital expenditures, and other obligations for a while.

The quarterly dividend was just raised 7.4%, to $0.58 a share. That was brought about, of course, by ONE Gas' solid capital position. What's more, our 3- to 5-year projections show that additional steady increases in the distribution will take place. The payout ratio during that period ought to be in the vicinity of 60%, which is reasonable.

These shares, though unfavorably ranked for Timeliness, hold good long-term total return potential.

Frederick L. Harris, III February 26, 2021

(A) Diluted EPS. Excludes nonrecurring gain: 2017, $0.06. Next earnings report due early May. Quarterly EPS for 2018 don't add up due to rounding.
(B) Dividends historically paid in early March, June, Sept., and Dec. ■ Dividend reinvestment plan. Direct stock purchase plan.
(C) In millions.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	80
Earnings Predictability	100

SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE 23.66 | P/E RATIO 14.3 (Trailing: 15.4 / Median: 19.0) | RELATIVE P/E RATIO 0.67 | DIV'D YLD 5.3% | VALUE LINE

TIMELINESS 3 Raised 11/20/20
SAFETY 3 Lowered 8/28/20
TECHNICAL 5 Lowered 2/12/21
BETA 1.05 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$18-$51	$35 (45%)

2024-26 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+110%)	23%
Low	30	(+25%)	10%

Institutional Decisions

	1Q2020	2Q2020	3Q2020
to Buy	108	88	132
to Sell	125	110	64
Hld's(000)	78322	83521	85672

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
High:	27.1	29.0	29.0	31.1	30.6	30.4	34.8	38.4	36.7	34.5	33.4	24.2
Low:	18.6	21.4	22.9	25.3	25.9	21.2	22.1	30.8	26.0	26.6	18.2	20.8

LEGENDS
— 0.45 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 5/15
Options: Yes
Shaded area indicates recession

Target Price Range 2024 | 2025 | 2026

% TOT. RETURN 1/21

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-22.4	26.6
3 yr.	-12.6	29.4
5 yr.	10.7	99.1

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	© VALUE LINE PUB. LLC	24-26
15.89	15.88	16.15	16.18	14.19	15.48	13.71	11.16	11.18	12.98	13.52	13.04	15.63	19.20	17.63	15.60	16.25	17.15	Revenues per sh	19.15
1.25	1.75	1.60	1.74	1.86	2.10	2.23	2.34	2.48	2.67	2.42	2.67	2.79	2.91	2.56	2.65	2.85	3.10	"Cash Flow" per sh	3.95
.86	1.23	1.05	1.14	1.19	1.35	1.45	1.52	1.52	1.57	1.44	1.34	1.23	1.38	1.12	1.60	1.70	1.85	Earnings per sh A	2.50
.43	.46	.51	.56	.61	.68	.75	.83	.90	.96	1.02	1.06	1.10	1.13	1.16	1.19	1.25	1.32	Div'ds Decl'd per sh B ■	1.50
1.60	1.26	.94	1.04	1.83	2.79	3.20	4.01	4.84	5.01	4.87	3.50	3.43	3.99	5.46	4.95	5.85	6.65	Cap'l Spending per sh	7.85
6.75	7.55	8.12	8.67	9.12	9.54	10.33	11.63	12.64	13.65	14.62	16.22	14.99	14.82	15.41	16.35	17.00	17.60	Book Value per sh C	21.50
57.96	58.65	59.22	59.46	59.59	59.75	60.43	63.31	65.43	68.33	70.97	79.48	79.55	85.51	92.39	101.00	103.00	105.00	Common Shs Outst'g D	115.00
16.6	11.9	17.2	15.9	15.0	16.8	18.4	16.9	18.9	18.0	17.9	21.7	27.9	22.6	28.3	15.6	Bold figures are	Value Line estimates	Avg Ann'l P/E Ratio	16.0
.88	.64	.91	.96	1.00	1.07	1.15	1.08	1.06	.95	.90	1.14	1.40	1.22	1.51	.80			Relative P/E Ratio	.90
3.0%	3.2%	2.8%	3.1%	3.4%	3.0%	2.8%	3.2%	3.1%	3.4%	3.9%	3.6%	3.2%	3.6%	3.7%	4.8%			Avg Ann'l Div'd Yield	3.8%

CAPITAL STRUCTURE as of 9/30/20
Total Debt $3271.4 mill. Due in 5 Yrs $1045 mill.
LT Debt $2531.6 mill. LT Interest $100 mill.

Leases, Uncapitalized Annual rentals $1.2 mill.
Pension Assets-12/19 $312.5 mill. Oblig. $439.4 mill.

Pfd Stock None

Common Stock 100,590,307 shs. as of 11/1/20

MARKET CAP: $2.4 billion (Mid Cap)

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		24-26
828.6	706.3	731.4	887.0	959.6	1036.5	1243.1	1641.3	1628.6	1575	1675	1800	Revenues ($mill)	2200
87.0	93.3	97.1	104.0	99.0	102.8	98.1	116.2	103.0	160	175	190	Net Profit ($mill)	280
22.4%	10.8%	--	--	5.9%	42.0%	--	--	--	21.0%	21.0%	21.0%	Income Tax Rate	21.0%
10.5%	13.2%	13.3%	11.7%	10.3%	9.9%	7.9%	7.1%	6.3%	10.2%	10.4%	10.6%	Net Profit Margin	12.7%
40.5%	45.0%	45.1%	48.0%	49.2%	38.5%	48.5%	62.4%	59.2%	61.0%	61.5%	62.0%	Long-Term Debt Ratio	58.0%
59.5%	55.0%	54.9%	52.0%	50.8%	61.5%	51.5%	37.6%	40.8%	39.0%	38.5%	38.0%	Common Equity Ratio	42.0%
1048.3	1337.6	1507.4	1791.9	2043.9	2097.2	2315.4	3373.9	3493.9	4250	4550	4900	Total Capital ($mill)	5875
1352.4	1578.0	1859.1	2134.1	2448.1	2623.8	2700.2	3653.5	4073.5	4400	4750	5100	Net Plant ($mill)	5800
8.9%	7.4%	6.8%	6.4%	5.4%	5.4%	5.1%	4.4%	4.0%	5.0%	5.0%	5.0%	Return on Total Cap'l	6.0%
13.9%	12.7%	11.7%	11.2%	9.5%	8.0%	8.2%	9.2%	7.2%	9.5%	10.0%	10.5%	Return on Shr. Equity	11.5%
13.9%	12.7%	11.7%	11.2%	9.5%	8.0%	8.2%	9.2%	7.2%	9.5%	10.0%	10.5%	Return on Com Equity	11.5%
6.7%	5.8%	4.8%	4.3%	2.8%	1.6%	.9%	1.7%	NMF	2.5%	2.5%	3.0%	Retained to Com Eq	4.5%
52%	55%	59%	61%	71%	80%	89%	82%	104%	75%	74%	73%	All Div'ds to Net Prof	62%

CURRENT POSITION ($MILL.)	2018	2019	9/30/20
Cash Assets	30.0	6.4	10.1
Other	633.2	646.1	344.7
Current Assets	663.2	652.5	354.8
Accts Payable	410.5	232.2	162.8
Debt Due	1004.4	1316.6	739.8
Other	165.9	183.1	201.1
Current Liab.	1580.8	1731.9	1103.7
Fix. Chg. Cov.	112%	176%	216%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '24-'26
Revenues	1.0%	8.0%	1.5%
"Cash Flow"	4.5%	2.0%	5.5%
Earnings	1.0%	-4.0%	10.5%
Dividends	7.5%	5.0%	4.0%
Book Value	5.5%	3.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	521.9	227.3	302.5	589.6	1641.3
2019	637.3	266.9	261.2	463.2	1628.6
2020	534.1	260.0	261.5	519.4	1575
2021	575	285	285	530	1675
2022	610	310	310	570	1800

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	1.19	.07	d.27	.39	1.38
2019	1.09	d.13	d.30	.46	1.12
2020	1.15	d.01	d.06	.52	1.60
2021	1.18	.01	d.05	.56	1.70
2022	1.25	.02	d.04	.62	1.85

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	--	.273	.273	.553	1.10
2018	--	.280	.280	.567	1.13
2019	--	.287	.287	.582	1.16
2020	--	.295	.295	.598	1.19
2021					

BUSINESS: South Jersey Industries, Inc. is a holding company. The company distributes natural gas in New Jersey and Maryland. South Jersey Gas rev. mix '19: residential, 47%; commercial, 23%; cogen. and electric gen., 12%; industrial, 18%. Acq. Elizabethtown Gas and Elkton Gas, 7/18. Nonutil. operations include South Jersey Energy, South Jersey Resources Group, South Jersey Exploration, Marina Energy, South Jersey Energy Service Plus, and SJI Midstream. Has about 1,100 employees. Off./dir. own less than 1% of common; BlackRock, 15.5%; The Vanguard Group, 11.4% (3/20 proxy). Pres. & CEO: Michael J. Renna. Chairman: Joseph M. Rigby. Inc.: NJ. Addr.: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Internet: www.sjindustries.com.

Shares of South Jersey Industries have traded in a relatively narrow range over the past few months, following a nice rally from late September though early November. The company posted a narrower share deficit for the September quarter, and we expect a favorable comparison for the December term. A decline in costs has supported the bottom line here. The company was set to report earnings for the fourth quarter as this Issue went to press. All told, we project that share net advanced roughly 40%, to $1.60 for full-year 2020, despite a top-line decline.

We anticipate greater revenue and moderate bottom-line improvement for the company for full-year 2021. Growth should continue from 2022 onward. South Jersey's utility business ought to further benefit from an expansion in the customer base. Infrastructure investments will allow the company to modernize its system and meet growing demand for natural gas within its service territories. Infrastructure replacement programs allow the company to earn an authorized return on approved investments. Regulatory initiatives should also pay off. Meanwhile, we look for better performance on the nonutility side. The Energy Group business ought to benefit from fuel supply management contracts and a reorganized wholesale marketing portfolio. Solar investment in support of the New Jersey Energy Master Plan, as well as legacy energy production activity will likely continue to boost the performance of the Energy Services line. Investment by the Midstream unit in long-term contracted energy infrastructure projects, such as the Penn East Pipeline, should bear fruit, too.

This stock is ranked to track the broader market for the coming six to 12 months. Looking further out, we anticipate solid bottom-line growth for the company over the pull to mid-decade. From the recent quotation, this stock offers attractive long-term total return potential. This is aided by a fairly healthy dividend yield. In addition, South Jersey Industries has above-average marks for Price Stability and Earnings Predictability. Income-seeking subscribers may want to take a closer look.

Michael Napoli, CFA *February 26, 2021*

(A) Based on economic egs. from 2007. GAAP EPS: '08, $1.29; '09, $0.97; '10, $1.11; '11, $1.49; '12, $1.49; '13, $1.28; '14, $1.46; '15, $1.52; '16, $1.56; '17, ($0.04); '18, $0.21; '19, $0.84. Excl. nonrecur. gain (loss): '09, ($0.22); '10, ($0.24); '11, $0.04; '12, ($0.03); '13, ($0.24); '14, ($0.11); '15, $0.08; '16, $0.22; '17, ($1.27); '18, ($1.17); '19, ($0.28). Next egs. rpt. due early May. (B) Div'ds paid early April, July, Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. reg. assets. In 2019: $665.9 mill., $7.21 per shr. (D) In mill., adj. for split.

Company's Financial Strength	B++
Stock's Price Stability	70
Price Growth Persistence	15
Earnings Predictability	65

SOUTHWEST GAS NYSE-SWX

RECENT PRICE **61.83** | P/E RATIO **14.2** (Trailing: 15.5; Median: 18.0) | RELATIVE P/E RATIO **0.67** | DIV'D YLD **3.8%** | VALUE LINE

TIMELINESS **3** Lowered 1/8/21
SAFETY **3** Lowered 1/4/91
TECHNICAL **5** Lowered 2/12/21
BETA .95 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$49-$121 $85 (35%)

2024-26 PROJECTIONS

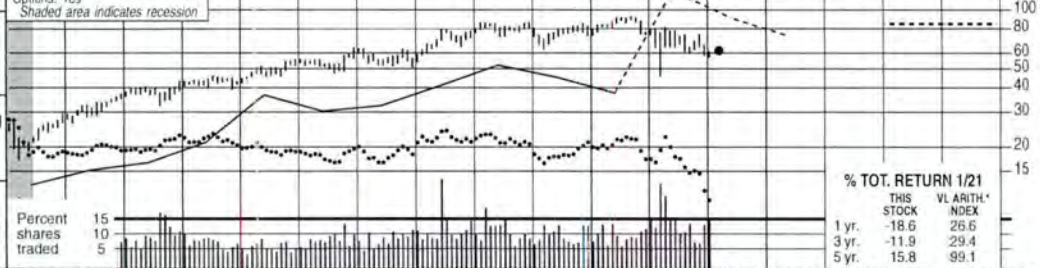
	Price	Gain	Ann'l Total Return
High	125	(+100%)	22%
Low	85	(+35%)	11%

Institutional Decisions

	1Q2020	2Q2020	3Q2020
to Buy	118	130	116
to Sell	155	123	137
Hld's(000)	47511	48082	46991

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
High:	37.3	43.2	46.1	56.0	64.2	63.7	79.6	86.9	86.0	92.9	81.6	62.7
Low:	26.3	32.1	39.0	42.0	47.2	50.5	53.5	72.3	62.5	73.3	45.7	57.0

LEGENDS
— 0.50 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



% TOT. RETURN 1/21

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-18.6	26.6
3 yr.	-11.9	29.4
5 yr.	15.8	99.1

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	© VALUE LINE PUB. LLC	24-26
43.59	48.47	50.28	48.53	42.00	40.18	41.07	41.77	42.08	45.61	52.00	51.82	53.00	54.31	56.72	**57.65**	**59.30**	**60.65**	Revenues per sh	**67.70**
5.20	5.97	6.21	5.76	6.16	6.46	6.81	7.73	8.24	8.47	8.62	9.29	8.83	8.14	9.40	**9.65**	**10.35**	**11.05**	"Cash Flow" per sh	**13.75**
1.25	1.98	1.95	1.39	1.94	2.27	2.43	2.86	3.11	3.01	2.92	3.18	3.62	3.68	3.94	**4.00**	**4.45**	**4.95**	Earnings per sh A	**6.50**
.82	.82	.86	.90	.95	1.00	1.06	1.18	1.32	1.46	1.62	1.80	1.98	2.08	2.18	2.26	**2.37**	**2.48**	Div'ds Decl'd per sh B■†	**2.80**
7.49	8.27	7.96	6.79	4.81	4.73	8.29	8.57	7.86	8.53	10.30	11.15	12.97	14.44	17.06	**14.05**	**16.95**	**18.85**	Cap'l Spending per sh	**26.15**
19.10	21.58	22.98	23.49	24.44	25.62	26.66	28.35	30.47	31.95	33.61	35.03	37.74	42.47	45.56	**47.35**	**50.00**	**52.85**	Book Value per sh	**63.10**
39.33	41.77	42.81	44.19	45.09	45.56	45.96	46.15	46.36	46.52	47.38	47.48	48.09	53.03	55.01	**57.00**	**59.00**	**61.00**	Common Shs Outst'g C	**65.00**
20.6	15.9	17.3	20.3	12.2	14.0	15.7	15.0	15.8	17.9	19.4	21.6	22.2	20.6	21.3	**17.4**	*Bold figures are*		Avg Ann'l P/E Ratio	**16.0**
1.10	.86	.92	1.22	.81	.89	.98	.95	.89	.94	.98	1.13	1.12	1.11	1.13	**.89**	*Value Line*		Relative P/E Ratio	**.90**
3.2%	2.6%	2.6%	3.2%	4.0%	3.2%	2.8%	2.8%	2.7%	2.7%	2.9%	2.6%	2.5%	2.7%	2.6%	3.3%	*estimates*		Avg Ann'l Div'd Yield	**2.7%**

CAPITAL STRUCTURE as of 9/30/20
Total Debt $2784.6 mill. **Due in 5 Yrs** $898.8 mill.
LT Debt $2685.7 mill. **LT Interest** $100.0 mill.
(Total interest coverage: 3.6x) (50% of Cap'l)
Leases, Uncapitalized Annual rentals $13.0 mill.
Pension Assets-12/19 $1027.8 mill. **Oblig.** $1405.7 mill.
Pfd Stock None

Common Stock 56,464,880 shs.
as of 10/30/20

MARKET CAP: $3.5 billion (Mid Cap)

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		24-26
1887.2	1927.8	1950.8	2121.7	2463.6	2460.5	2548.8	2880.0	3119.9	**3285**	**3500**	**3700**	Revenues ($mill)	**4400**
112.3	133.3	145.3	141.1	138.3	152.0	173.8	182.3	213.9	**225**	**260**	**295**	Net Profit ($mill)	**395**
36.2%	36.2%	35.0%	35.7%	36.4%	33.9%	32.8%	25.3%	20.5%	**22.0%**	**21.0%**	**21.0%**	Income Tax Rate	**21.0%**
6.0%	6.9%	7.4%	6.7%	5.6%	6.2%	6.8%	6.3%	6.9%	**6.8%**	**7.4%**	**8.0%**	Net Profit Margin	**9.0%**
43.2%	49.2%	49.4%	52.4%	49.3%	48.2%	49.8%	48.3%	47.9%	**50.5%**	**50.5%**	**50.0%**	Long-Term Debt Ratio	**48.0%**
56.8%	50.8%	50.6%	47.6%	50.7%	51.8%	50.2%	51.7%	52.1%	**49.5%**	**49.5%**	**50.0%**	Common Equity Ratio	**52.0%**
2155.9	2576.9	2793.7	3123.9	3143.5	3213.5	3613.3	4359.3	4806.4	**5450**	**5950**	**6425**	Total Capital ($mill)	**7850**
3218.9	3343.8	3486.1	3658.4	3891.1	4132.0	4523.7	5093.2	5685.2	**6150**	**6400**	**6750**	Net Plant ($mill)	**8000**
6.4%	6.4%	6.3%	5.7%	5.5%	5.8%	5.8%	5.2%	5.4%	**5.0%**	**5.5%**	**5.5%**	Return on Total Cap'l	**6.0%**
9.2%	10.2%	10.3%	9.5%	8.7%	9.1%	9.6%	8.1%	8.5%	**8.5%**	**9.0%**	**9.0%**	Return on Shr. Equity	**9.5%**
9.2%	10.2%	10.3%	9.5%	8.7%	9.1%	9.6%	8.1%	8.5%	**8.5%**	**9.0%**	**9.0%**	Return on Com Equity	**9.5%**
5.3%	6.1%	6.1%	5.0%	4.0%	4.1%	4.5%	3.6%	3.9%	**3.5%**	**4.0%**	**4.5%**	Retained to Com Eq	**5.0%**
43%	40%	41%	47%	54%	55%	53%	55%	54%	57%	**54%**	**51%**	All Div'ds to Net Prof	**46%**

CURRENT POSITION ($MILL.)	2018	2019	9/30/20
Cash Assets	85.4	49.5	23.9
Other	754.4	810.4	708.9
Current Assets	839.8	859.9	732.8
Accts Payable	249.0	238.9	175.5
Debt Due	185.1	374.5	98.9
Other	504.5	466.5	564.8
Current Liab.	938.6	1079.9	839.2
Fix. Chg. Cov.	370%	340%	259%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '17-'19 to '24-'26
Revenues	1.5%	5.0%	3.0%
"Cash Flow"	4.0%	1.5%	6.5%
Earnings	8.0%	4.5%	8.0%
Dividends	8.5%	9.5%	4.5%
Book Value	6.0%	6.5%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	754.3	670.9	668.1	786.7	2880.0
2019	833.6	713.0	725.2	848.1	3119.9
2020	836.3	757.2	791.2	**900.3**	**3285**
2021	**875**	**825**	**850**	**950**	**3500**
2022	**925**	**875**	**900**	**1000**	**3700**

Cal-endar	EARNINGS PER SHARE A D Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	1.63	.44	.25	1.36	3.68
2019	1.77	.41	.10	1.67	3.94
2020	1.31	.68	.32	**1.69**	**4.00**
2021	**1.70**	**.65**	**.32**	**1.78**	**4.45**
2022	**1.85**	**.75**	**.40**	**1.95**	**4.95**

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.450	.495	.495	.495	1.94
2018	.495	.520	.520	.520	2.06
2019	.520	.545	.545	.545	2.16
2020	.545	.570	.570	.570	2.26
2021	.570				

BUSINESS: Southwest Gas Holdings, Inc. is the parent holding company of Southwest Gas and Centuri Group. Southwest Gas is a regulated gas distributor serving about 2.1 million customers in parts of Arizona, Nevada, and California. Centuri provides construction services. 2019 margin mix: residential and small commercial, 84%; large commercial and industrial, 3%; transportation, 13%. Total throughput: 2.3 billion therms. Has 8,944 employees. Off. & dir. own .8% of common stock; BlackRock, Inc., 13.5%; The Vanguard Group, Inc., 10.3%; T.Rowe Price Assoc., Inc., 6.8% (3/20 Proxy). Chairman: Michael J. Melarkey. Pres. & CEO: John P. Hester. Inc.: DE. Address: 8360 S. Durango Drive, P.O. Box 98510 Las Vegas, Nevada 89193. Tel.: 702-876-7237. Web: www.swgas.com.

Shares of Southwest Gas have perked up in price in recent weeks, following a selloff that began in the first half of November. The company reported favorable comparisons in recent periods, and we expect solid results for the fourth quarter. Southwest has benefited from healthy results from its Centuri infrastructure services segment in recent times. Results here have been supported by increasing demand from core customers, as it provided emergency restoration services to its electric customers following regional storms. Meanwhile, the company's regulated utility operations further benefited from healthy regional growth. For full-year 2020, we expect revenue of $3.285 billion and earnings per share of $4.00.

Solid growth ought to continue from 2021 onward. The company's utility operation should further benefit from expansion in the customer base. This line continues to make infrastructure installation progress supporting its territory expansions in Nevada. Rate relief should also provide support here. The company depends on such approved revenue increases to offset rising expenses and allow it to earn a satisfactory return on investment. Meantime, Centuri, the company's infrastructure services business, should fare relatively well. This operation derives its revenue from the installation, replacement, repair, and maintenance of energy distribution systems. It ought to further benefit from the ongoing need for utilities to replace their aging infrastructure. Centuri has a robust client base, many with multiyear pipeline replacement programs. Measures by Southwest Gas to control operating expenses should support profitability, too.

This stock is ranked to perform in line with the broader market averages for the coming six to 12 months. Looking further out, we anticipate healthy growth in revenues and earnings per share for the company over the pull to mid-decade. From the recent quotation, these shares offer attractive long-term total return potential. The payout should continue to rise in the years ahead, as well. Southwest Gas earns favorable marks for Financial Strength, Price Stability, and Earnings Predictability.

Michael Napoli, CFA *February 26, 2021*

(A) Diluted earnings. Excl. nonrec. gains (losses): '05, (11¢); '06, 7¢. Next egs. report due early March. (B) Dividends historically paid early March, June, September, and December.
■† Div'd reinvestment and stock purchase plan avail. (C) In millions.
(D) Totals may not sum due to rounding.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	65
Earnings Predictability	95

SPIRE INC. NYSE-SR

RECENT PRICE 63.97 | P/E RATIO 16.6 (Trailing: 34.2 Median: 19.0) | RELATIVE P/E RATIO 0.78 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 4 Lowered 2/19/21
SAFETY 2 Raised 6/20/03
TECHNICAL 5 Lowered 2/19/21
BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$50-$116	$83 (30%)

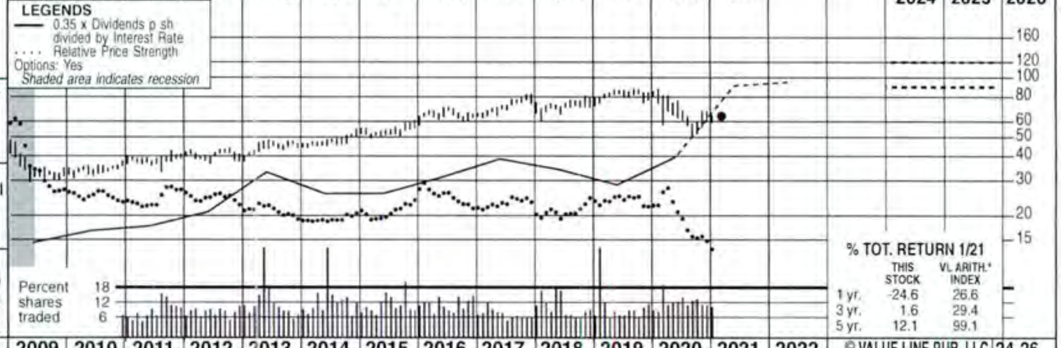
2024-26 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	120	(+90%)	20%
Low	90	(+40%)	12%

Institutional Decisions

	1Q2020	2Q2020	3Q2020
to Buy	120	127	145
to Sell	116	130	121
Hld's(000)	42039	40679	40642

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
High:	37.8	42.8	44.0	48.5	55.2	61.0	71.2	82.9	81.1	88.0	88.0	65.7
Low:	30.8	32.9	36.5	37.4	44.0	49.1	57.1	62.3	60.1	71.7	50.6	59.3



Target Price Range 2024 | 2025 | 2026

% TOT. RETURN 1/21

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-24.6	26.6
3 yr.	1.6	29.4
5 yr.	12.1	99.1

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	© VALUE LINE PUB. LLC	24-26
75.43	93.51	93.40	100.44	85.49	77.83	71.48	49.90	31.10	37.68	45.59	33.68	36.07	38.78	38.30	35.96	**34.95**	**35.35**	Revenues per sh A	**58.20**
2.98	3.81	3.87	4.22	4.56	4.11	4.62	4.58	3.12	3.87	6.15	6.16	6.54	7.55	7.12	5.25	**7.85**	**8.35**	"Cash Flow" per sh	**10.35**
1.90	2.37	2.31	2.64	2.92	2.43	2.86	2.79	2.02	2.35	3.16	3.24	3.43	4.33	3.52	1.44	**3.85**	**4.15**	Earnings per sh A B	**5.15**
1.37	1.40	1.45	1.49	1.53	1.57	1.61	1.66	1.70	1.76	1.84	1.96	2.10	2.25	2.37	2.49	**2.60**	**2.72**	Div'ds Decl'd per sh C ■	**3.10**
2.84	2.97	2.72	2.57	2.36	2.56	3.02	4.83	4.00	3.96	6.68	6.42	9.08	9.86	16.15	12.37	**11.25**	**11.30**	Cap'l Spending per sh	**11.45**
17.31	18.85	19.79	22.12	23.32	24.02	25.56	26.67	32.00	34.93	36.30	38.73	41.26	44.51	45.14	44.19	**52.45**	**54.80**	Book Value per sh D	**72.00**
21.17	21.36	21.65	21.99	22.17	22.29	22.43	22.55	32.70	43.18	43.36	45.65	48.26	50.67	50.97	51.60	**52.50**	**53.50**	Common Shs Outst'g E	**55.00**
16.2	13.6	14.2	14.3	13.4	13.7	13.0	14.5	21.3	19.8	16.5	19.6	19.8	16.7	22.8	NMF	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**20.5**
.86	.73	.75	.86	.89	.87	.82	.92	1.20	1.04	.83	1.03	1.00	.90	1.21	NMF	*estimates*		Relative P/E Ratio	**1.15**
4.4%	4.3%	4.4%	3.9%	3.9%	4.7%	4.3%	4.1%	4.0%	3.8%	3.5%	3.1%	3.1%	3.1%	3.0%	3.4%			Avg Ann'l Div'd Yield	**3.0%**

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		24-26
	1603.3	1125.5	1017.0	1627.2	1976.4	1537.3	1740.7	1965.0	1952.4	1855.4	**1835**	**1890**	Revenues ($mill) A	**3200**
	63.8	62.6	52.8	84.6	136.9	144.2	161.6	214.2	184.6	88.6	**200**	**220**	Net Profit ($mill)	**285**
	31.4%	29.6%	25.0%	27.6%	31.2%	32.5%	32.4%	32.4%	15.7%	12.3%	**20.5%**	**21.0%**	Income Tax Rate	**23.5%**
	4.0%	5.6%	5.2%	5.2%	6.9%	9.4%	9.3%	10.9%	9.5%	4.8%	**10.9%**	**11.6%**	Net Profit Margin	**8.9%**
	38.9%	36.1%	46.6%	55.1%	53.0%	50.9%	50.0%	45.7%	45.0%	49.0%	**49.0%**	**49.0%**	Long-Term Debt Ratio	**45.0%**
	61.1%	63.9%	53.4%	44.9%	47.0%	49.1%	50.0%	54.3%	55.0%	51.0%	**51.0%**	**51.0%**	Common Equity Ratio	**55.0%**
	937.7	941.0	1959.0	3359.4	3345.1	3601.9	3986.3	4155.5	4625.6	4946.0	**5400**	**5750**	Total Capital ($mill)	**7200**
	928.7	1019.3	1776.6	2759.7	2941.2	3300.9	3665.2	3970.5	4352.0	4680.1	**5000**	**5300**	Net Plant ($mill)	**6700**
	8.1%	7.9%	3.3%	3.1%	5.1%	4.9%	5.0%	6.3%	5.1%	2.9%	**5.0%**	**5.5%**	Return on Total Cap'l	**5.5%**
	11.1%	10.4%	5.0%	5.6%	8.7%	8.2%	8.1%	9.5%	7.3%	3.5%	**7.5%**	**7.5%**	Return on Shr. Equity	**7.0%**
	11.1%	10.4%	5.0%	5.6%	8.7%	8.2%	8.1%	9.5%	7.9%	3.2%	**7.5%**	**7.5%**	Return on Com Equity	**7.0%**
	4.9%	4.3%	1.0%	1.5%	3.7%	3.3%	3.3%	4.7%	2.7%	NMF	**2.0%**	**2.0%**	Retained to Com Eq	**2.5%**
	56%	59%	81%	73%	58%	59%	60%	51%	66%	NMF	**76%**	**73%**	All Div'ds to Net Prof	**65%**

CAPITAL STRUCTURE as of 12/31/20
Total Debt $3324.5 mill. **Due in 5 Yrs** $1690.0 mill.
LT Debt $2517.6 mill. **LT Interest** $130.0 mill.
(Total interest coverage: 2.0x)

Leases, Uncapitalized Annual rentals $8.8 mill.
Pension Assets-9/20 $897.9 mill.
Oblig. $1401.3 mill.
Pfd Stock $242.0 mill. **Pfd Div'd** $14.8 mill.
Common Stock 51,664,553 shs.
as of 1/31/21

MARKET CAP: $3.3 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2019	2020	12/31/20
Cash Assets	5.8	4.1	3.5
Other	608.7	586.5	766.5
Current Assets	614.5	590.6	770.0
Accts Payable	301.5	243.3	260.8
Debt Due	783.2	708.4	806.9
Other	384.1	497.5	479.0
Current Liab.	1468.8	1449.2	1546.7
Fix. Chg. Cov.	272%	373%	380%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '18-'20 to '24-'26
Revenues	-8.0%	--	7.5%
"Cash Flow"	4.5%	8.5%	7.5%
Earnings	1.5%	4.5%	9.0%
Dividends	4.5%	6.0%	4.5%
Book Value	7.0%	5.5%	8.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2018	561.8	813.4	350.6	239.2	1965.0
2019	602.0	803.5	321.3	225.6	1952.4
2020	566.9	715.5	321.1	251.9	1855.4
2021	512.6	**732.4**	**335**	**255**	**1835**
2022	**530**	**748**	**346**	**266**	**1890**

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2018	2.39	2.03	.52	d.51	4.33
2019	1.32	3.04	d.09	d.74	3.52
2020	1.24	2.54	d1.87	d.45	1.44
2021	1.65	**2.66**	**.22**	**d.68**	**3.85**
2022	**1.75**	**2.74**	**.30**	**d.64**	**4.15**

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2017	.525	.525	.525	.525	2.10
2018	.5625	.5625	.5625	.5625	2.25
2019	.5925	.5925	.5925	.5925	2.37
2020	.6225	.6225	.6225	.6225	2.49
2021	.65				

BUSINESS: Spire Inc., formerly known as the Laclede Group, Inc., is a holding company for natural gas utilities, which distributes natural gas across Missouri, including the cities of St. Louis and Kansas City, Alabama, and Mississippi. Has roughly 1.7 million customers. Acquired Missouri Gas 9/13, Alabama Gas Co 9/14. Utility therms sold and transported in fiscal 2020: 3.3 bill. Revenue mix for regulated operations: residential, 68%; commercial and industrial, 22%; transportation, 6%; other, 4%. Has about 3,583 employees. Officers and directors own 3.0% of common shares; BlackRock, 12.0% (1/21 proxy). Chairman: Edward Glotzbach; CEO: Suzanne Sitherwood. Inc.: Missouri. Address: 700 Market Street, St. Louis, Missouri 63101. Tel.: 314-342-0500. Internet: www.spireenergy.com.

Spire began fiscal 2021 (which ends September 30th) in strong shape. First-quarter earnings per share of $1.65 were 33% higher than the year-ago figure of $1.24. That was brought about partly by the Gas Utility division, supported by higher Infrastructure System Replacement Surcharge (ISRS) revenues, an expanded customer base, plus diminished operating costs. What's more, the Gas Marketing unit enjoyed wider margins, driven by favorable derivative activity and fair value measurements. Right now, it appears that the bottom line will jump to $3.85 a share for the full year, versus fiscal 2020's low $1.44 total (reflecting pandemic-related effects). Assuming that business conditions cooperate in fiscal 2022, share net stands to advance to $4.15.

The capital spending budget for this year is anticipated to be around $590 million. (That's 7.5% lower than the fiscal 2020 amount of about $638 million.) Funds are being allocated to such segments as infrastructure upgrades at the utilities and new business development initiatives. Leadership says that it expects total expenditures during the 2021-2025 horizon to be some $3 billion, which appears achievable.

We believe good things are in store out to 2024-2026. The gas utilities boast 1.7 million customers in Mississippi, Alabama, and Missouri, providing a measure of regional diversity. Moreover, the other operations, especially pipelines, hold promising potential. Further expansionary projects and technological enhancements in customer service and elsewhere ought to help, too. Lastly, Spire's decent finances make acquisitions possible. The usual risks include unfortunate events like leaks and pipeline ruptures. Still, at the present configuration, annual share-net growth might be in the range of 6%-8% over the 3- to 5-year period.

The stock should draw the attention of some investors. Capital appreciation possibilities through mid-decade look appealing. Consider, also, the 18-month upside potential. Another plus is the quarterly dividend, which was just raised 4.4%. Notably, the yield compares favorably to those of other equities in *Value Line's* Natural Gas Utility Industry.

Frederick L. Harris, III February 26, 2021

(A) Fiscal year ends Sept. 30th. (B) Based on diluted shares outstanding. Excludes nonrecurring loss: '06, 7¢. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late April. (C) Dividends paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '20: $1,171.6 mill., $22.71/sh. (E) In millions. (F) Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	50

Duke Energy Kentucky, Inc.
Summary of Risk Premium Models for the
Proxy Group of Seven Natural Gas Distribution Companies

	Proxy Group of Seven Natural Gas Distribution Companies
Predictive Risk Premium Model (PRPM) (1)	10.96 %
Risk Premium Using an Adjusted Total Market Approach (2)	10.33 %
Average	10.65 %

Notes:
(1) From page 2 of this Attachment.
(2) From page 3 of this Attachment.

Duke Energy Kentucky, Inc.
Indicated ROE
Derived by the Predictive Risk Premium Model (1)

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Proxy Group of Seven Natural Gas Distribution Companies	LT Average Predicted Variance	Spot Predicted Variance	Recommended Variance (2)	GARCH Coefficient	Predicted Risk Premium (3)	Risk-Free Rate (4)	Indicated ROE (5)
Atmos Energy Corporation	0.34%	0.29%	0.31%	2.2515	8.76%	2.73%	11.49%
New Jersey Resources Corporation	0.38%	0.57%	0.47%	2.0412	12.27%	2.73%	15.00%
Northwest Natural Holding Company	0.33%	0.31%	0.32%	1.5418	6.03%	2.73%	8.76%
ONE Gas, Inc.	0.30%	0.44%	0.37%	4.3630	21.15%	2.73%	NMF
South Jersey Industries, Inc.	0.39%	0.69%	0.54%	1.5878	10.73%	2.73%	13.46%
Southwest Gas Holdings, Inc.	0.44%	0.35%	0.39%	1.3752	6.71%	2.73%	9.44%
Spire Inc.	0.71%	0.48%	0.60%	0.9448	7.00%	2.73%	9.73%
						Average	11.31%
						Median	10.61%
						Average of Mean and Median	10.96%

Notes:

(1) The Predictive Risk Premium Model uses historical data to generate a predicted variance and a GARCH coefficient. The historical data used are the equity risk premiums for the first available trading month as reported by Bloomberg Professional Service.

(2) Given current market conditions, I recommend using average of the the long-term average predicted variance and the spot variance.

(3) (1+(Column [3] * Column [4])^12) - 1.

(4) From note 2 on page 2 of Attachment DWD-4.

(5) Column [5] + Column [6].

Duke Energy Kentucky, Inc.
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Seven Natural Gas Distribution Companies	
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	3.44	%
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A2 Rated Public Utility Bonds	0.42	(2)
3.	Adjusted Prospective Yield on A2 Rated Public Utility Bonds	3.86	%
4.	Adjustment to Reflect Bond Rating Difference of Proxy Group	0.05	(3)
5.	Adjusted Prospective Bond Yield	3.91	%
6.	Equity Risk Premium (4)	6.42	
7.	Risk Premium Derived Common Equity Cost Rate	10.33	%

Notes:
(1) Consensus forecast of Moody's Aaa Rated Corporate bonds from Blue Chip Financial Forecasts (see pages 10 and 11 of this
(2) The average yield spread of A2 rated public utility bonds over Aaa rated corporate bonds of 0.42% from page 4 of this Attachment.
(3) Adjustment to reflect the A2/A3 Moody's LT issuer rating of the Utility Proxy Group as shown on page 5 of this Attachment. The 0.05% upward adjustment is derived by taking 1/6 of the spread between A2 and Baa2 Public Utility Bonds (1/6 * 0.27% = 0.05%) as derived from page 4 of this Attachment.
(4) From page 7 of this Attachment.

Duke Energy Kentucky, Inc.
Interest Rates and Bond Spreads for
Moody's Corporate and Public Utility Bonds

Selected Bond Yields - Moody's

	[1]	[2]	[3]
	Aaa Rated Corporate Bond	A2 Rated Public Utility Bond	Baa2 Rated Public Utility Bond
Mar-2021	3.04 %	3.44 %	3.72 %
Feb-2021	2.70	3.09	3.37
Jan-2021	2.45	2.91	3.18
Average	2.73 %	3.15 %	3.42 %

Selected Bond Spreads

A2 Rated Public Utility Bonds Over Aaa Rated Corporate Bonds:
0.42 % (1)

Baa2 Rated Public Utility Bonds Over A2 Rated Public Utility Bonds:
0.27 % (2)

Notes:
(1) Column [2] - Column [1].
(2) Column [3] - Column [2].

Source of Information:
Bloomberg Professional Service

Duke Energy Kentucky, Inc.
Comparison of Long-Term Issuer Ratings for
Proxy Group of Seven Natural Gas Distribution Companies

	Moody's Long-Term Issuer Rating March 2021		Standard & Poor's Long-Term Issuer Rating March 2021	
Proxy Group of Seven Natural Gas Distribution Companies	Long-Term Issuer Rating (1)	Numerical Weighting (2)	Long-Term Issuer Rating (1)	Numerical Weighting (2)
Atmos Energy Corporation	A1	5.0	A-	7.0
New Jersey Resources Corporation	A1	5.0	NR	- -
Northwest Natural Holding Company	Baa1	8.0	A+	5.0
ONE Gas, Inc.	A3	7.0	BBB+	8.0
South Jersey Industries, Inc.	A3	7.0	BBB	9.0
Southwest Gas Holdings, Inc.	Baa1	8.0	A-	7.0
Spire Inc.	A1/A2	5.5	A-	7.0
Average	A2/A3	6.5	A-	7.2

Notes:

(1) Ratings are that of the average of each company's utility operating subsidiaries.
(2) From page 6 of this Attachment.

Source Information: Moody's Investors Service
Standard & Poor's Global Utilities Rating Service

Numerical Assignment for
Moody's and Standard & Poor's Bond Ratings

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's Bond Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-
B1	14	B+
B2	15	B
B3	16	B-

Duke Energy Kentucky, Inc.
Judgment of Equity Risk Premium for
Proxy Group of Seven Natural Gas Distribution Companies

Line No.		Proxy Group of Seven Natural Gas Distribution Companies
1.	Calculated equity risk premium based on the total market using the beta approach (1)	7.99 %
2.	Mean equity risk premium based on a study using the holding period returns of public utilities with A rated bonds (2)	5.57
3.	Predicted Equity Risk Premium Based on Regression Analysis of 798 Fully-Litigated Natural Gas Utility Rate Cases	5.69
4.	Average equity risk premium	6.42 %

Notes: (1) From page 8 of this Attachment.
(2) From page 12 of this Attachment.
(3) From page 13 of this Attachment.

Duke Energy Kentucky, Inc.
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Proxy Group of Seven Natural Gas Distribution Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Seven Natural Gas Distribution Companies
	Ibbotson-Based Equity Risk Premiums:	
1.	Ibbotson Equity Risk Premium (1)	5.92 %
2.	Regression on Ibbotson Risk Premium Data (2)	8.83
3.	Ibbotson Equity Risk Premium based on PRPM (3)	9.40
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	5.03
5.	Equity Risk Premium Based on Value Line S&P 500 Companies (5)	10.77
6.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	12.17
7.	Conclusion of Equity Risk Premium	8.69 %
8.	Adjusted Beta (7)	0.92
9.	Forecasted Equity Risk Premium	7.99 %

Notes provided on page 9 of this Attachment.

Duke Energy Kentucky, Inc.
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Proxy Group of Seven Natural Gas Distribution Companies

Notes:

(1) Based on the arithmetic mean historical monthly returns on large company common stocks from Duff & Phelps 2021 SBBI® Yearbook minus the arithmetic mean monthly yield of Moody's average Aaa and Aa corporate bonds from 1928-2020.

(2) This equity risk premium is based on a regression of the monthly equity risk premiums of large company common stocks relative to Moody's average Aaa and Aa rated corporate bond yields from 1928-2020 referenced in Note 1 above.

(3) The Predictive Risk Premium Model (PRPM) is discussed in the accompanying direct testimony. The Ibbotson equity risk premium based on the PRPM is derived by applying the PRPM to the monthly risk premiums between Ibbotson large company common stock monthly returns and average Aaa and Aa corporate monthly bond yields, from January 1928 through March 2021.

(4) The equity risk premium based on the Value Line Summary and Index is derived by subtracting the average consensus forecast of Aaa corporate bonds of 3.44% (from page 3 of this Attachment) from the projected 3-5 year total annual market return of 8.47% (described fully in note 1 on page 2 of Attachment DWD-4).

(5) Using data from Value Line for the S&P 500, an expected total return of 14.21% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 3.44% results in an expected equity risk premium of 10.77%.

(6) Using data from the Bloomberg Professional Service for the S&P 500, an expected total return of 15.61% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 3.44% results in an expected equity risk premium of 12.17%.

(7) Average of mean and median beta from Attachment DWD-4.

Sources of Information:

Stocks, Bonds, Bills, and Inflation - 2020 SBBI Yearbook, John Wiley & Sons, Inc.
Industrial Manual and Mergent Bond Record Monthly Update.
Value Line Summary and Index
Blue Chip Financial Forecasts, April 1, 2021 and December 1, 2020
Bloomberg Professional Service

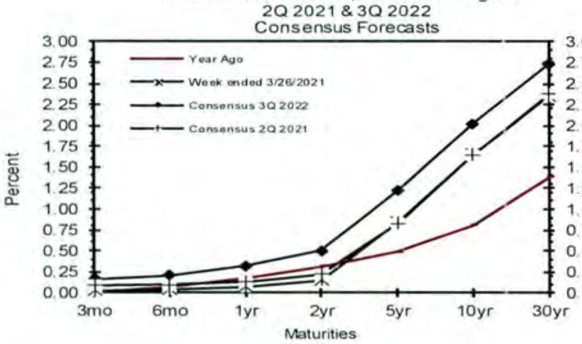
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	2Q	3Q	4Q	1Q	2Q	3Q
Interest Rates	Mar 26	Mar 19	Mar 12	Mar 5	Feb	Jan	Dec	1Q 2021*	2021	2021	2021	2022	2022	2022
Federal Funds Rate	0.07	0.07	0.07	0.07	0.08	0.09	0.09	0.08	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Prime Rate	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**
LIBOR, 3-mo.	0.20	0.19	0.18	0.18	0.19	0.22	0.23	0.20	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Commercial Paper, 1-mo.	0.07	0.07	0.07	0.06	0.06	0.08	0.09	0.07	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**
Treasury bill, 3-mo.	0.02	0.02	0.04	0.04	0.04	0.08	0.09	0.05	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**
Treasury bill, 6-mo.	0.04	0.05	0.06	0.07	0.06	0.09	0.09	0.07	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**
Treasury bill, 1 yr.	0.07	0.07	0.09	0.08	0.07	0.10	0.10	0.08	**0.1**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**
Treasury note, 2 yr.	0.14	0.15	0.16	0.14	0.12	0.13	0.14	0.13	**0.2**	**0.3**	**0.3**	**0.4**	**0.4**	**0.5**
Treasury note, 5 yr.	0.84	0.85	0.82	0.73	0.54	0.45	0.39	0.61	**0.8**	**0.9**	**1.0**	**1.1**	**1.1**	**1.2**
Treasury note, 10 yr.	1.65	1.66	1.57	1.49	1.26	1.08	0.93	1.32	**1.6**	**1.7**	**1.8**	**1.9**	**2.0**	**2.0**
Treasury note, 30 yr.	2.35	2.41	2.30	2.25	2.04	1.82	1.67	2.08	**2.4**	**2.5**	**2.5**	**2.6**	**2.7**	**2.7**
Corporate Aaa bond	3.15	3.23	3.13	3.06	2.84	2.64	2.52	2.88	**3.0**	**3.1**	**3.2**	**3.3**	**3.4**	**3.4**
Corporate Baa bond	3.63	3.71	3.62	3.52	3.30	3.14	3.03	3.36	**3.9**	**4.0**	**4.1**	**4.2**	**4.3**	**4.4**
State & Local bonds	2.75	2.74	2.72	2.77	2.63	2.65	2.70	2.68	**2.7**	**2.9**	**3.0**	**3.0**	**3.1**	**3.2**
Home mortgage rate	3.17	3.09	3.05	3.02	2.81	2.74	2.68	2.88	**3.2**	**3.3**	**3.4**	**3.5**	**3.6**	**3.7**

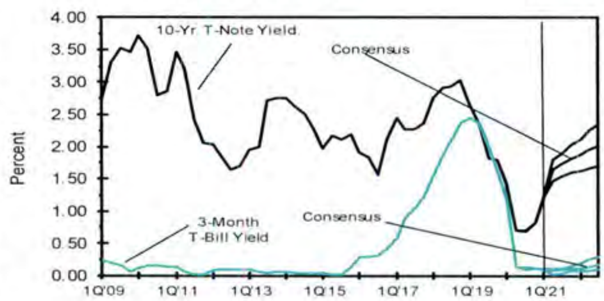
	History								Consensus Forecasts-Quarterly					
	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q
Key Assumptions	2019	2019	2019	2020	2020	2020	2020	2021**	2021	2021	2021	2022	2022	2022
Fed's AFE $ Index	110.4	110.6	110.5	111.4	112.4	107.3	105.2	103.4	**104.0**	**103.9**	**103.9**	**103.6**	**103.5**	**103.4**
Real GDP	1.5	2.6	2.4	-5.0	-31.4	33.4	4.3	4.3	**8.1**	**6.9**	**4.8**	**3.5**	**3.0**	**2.7**
GDP Price Index	2.5	1.5	1.4	1.4	-1.8	3.5	2.0	2.2	**2.1**	**2.1**	**2.0**	**1.9**	**2.1**	**2.2**
Consumer Price Index	3.5	1.3	2.6	1.0	-3.1	4.7	2.4	2.8	**2.4**	**2.1**	**2.0**	**2.0**	**2.1**	**2.2**
PCE Price Index	2.5	1.4	1.5	1.3	-1.6	3.7	1.5	2.7	**2.2**	**2.0**	**1.9**	**1.9**	**2.0**	**2.1**

Forecasts for interest rates and the Federal Reserve's Major Currency Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index and Consumer Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; LIBOR quotes from Intercontinental Exchange. All interest rate data are sourced from Haver Analytics. Historical data for Fed's Major Currency Index are from FRSR H.10. Historical data for Real GDP and GDP Chained Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index (CPI) history is from the Department of Labor's Bureau of Labor Statistics (BLS). *Interest rate data for 1Q 2021 based on historical data through the week ended March 26. **Data for 1Q 2021 for the Fed's AFE $ Index based on data through the week ended March 26. Figures for 1Q 2021 Real GDP, GDP Chained Price Index and CPI and PCE Price Index are consensus forecasts from the March 2021 survey.

U.S. Treasury Yield Curve
Week ended March 26, 2021 & Year Ago vs.
2Q 2021 & 3Q 2022
Consensus Forecasts



U.S. 3-Mo. T-Bills & 10-Yr. T-Note Yield
(Quarterly Average)
Forecast



Corporate Bond Spreads
As of week ended March 26, 2020

U.S. Treasury Yield Curve
As of week ended March 26, 2020

Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2022 through 2026 and averages for the five-year periods 2022-2026 and 2027-2031. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

		Average For The Year					Five-Year Averages	
		2022	2023	2024	2025	2026	2022-2026	2027-2031
1. Federal Funds Rate	**CONSENSUS**	**0.1**	**0.3**	**0.7**	**1.2**	**1.5**	**0.8**	**1.8**
	Top 10 Average	0.2	0.7	1.4	2.0	2.4	1.3	2.5
	Bottom 10 Average	0.1	0.1	0.2	0.4	0.6	0.3	1.2
2. Prime Rate	**CONSENSUS**	**3.3**	**3.5**	**3.9**	**4.3**	**4.6**	**3.9**	**4.9**
	Top 10 Average	3.4	3.7	4.4	5.0	5.4	4.4	5.4
	Bottom 10 Average	3.2	3.2	3.3	3.5	3.8	3.4	4.5
3. LIBOR, 3-Mo.	**CONSENSUS**	**0.4**	**0.6**	**1.1**	**1.5**	**1.8**	**1.1**	**2.2**
	Top 10 Average	0.5	1.0	1.7	2.2	2.6	1.6	2.7
	Bottom 10 Average	0.3	0.3	0.5	0.8	1.1	0.6	1.6
4. Commercial Paper, 1-Mo	**CONSENSUS**	**0.3**	**0.7**	**1.2**	**1.6**	**1.9**	**1.1**	**2.1**
	Top 10 Average	0.4	0.9	1.6	2.1	2.4	1.5	2.5
	Bottom 10 Average	0.2	0.4	0.8	1.2	1.5	0.8	1.7
5. Treasury Bill Yield, 3-Mo	**CONSENSUS**	**0.2**	**0.4**	**0.8**	**1.2**	**1.5**	**0.8**	**1.9**
	Top 10 Average	0.3	0.7	1.5	2.0	2.4	1.4	2.5
	Bottom 10 Average	0.1	0.1	0.2	0.5	0.7	0.3	1.3
6. Treasury Bill Yield, 6-Mo	**CONSENSUS**	**0.2**	**0.5**	**0.9**	**1.3**	**1.6**	**0.9**	**2.0**
	Top 10 Average	0.3	0.8	1.6	2.1	2.5	1.5	2.6
	Bottom 10 Average	0.1	0.2	0.3	0.5	0.8	0.4	1.4
7. Treasury Bill Yield, 1-Yr	**CONSENSUS**	**0.3**	**0.6**	**1.0**	**1.4**	**1.8**	**1.0**	**2.1**
	Top 10 Average	0.5	1.0	1.7	2.3	2.6	1.6	2.7
	Bottom 10 Average	0.2	0.3	0.4	0.7	0.9	0.5	1.6
8. Treasury Note Yield, 2-Yr	**CONSENSUS**	**0.4**	**0.8**	**1.2**	**1.6**	**1.9**	**1.2**	**2.3**
	Top 10 Average	0.7	1.2	1.9	2.4	2.8	1.8	2.9
	Bottom 10 Average	0.2	0.3	0.6	0.8	1.1	0.6	1.7
9. Treasury Note Yield, 5-Yr	**CONSENSUS**	**0.8**	**1.2**	**1.6**	**2.0**	**2.3**	**1.5**	**2.5**
	Top 10 Average	1.1	1.6	2.3	2.8	3.1	2.1	3.1
	Bottom 10 Average	0.5	0.7	1.0	1.2	1.4	1.0	1.9
10. Treasury Note Yield, 10-Yr	**CONSENSUS**	**1.3**	**1.7**	**2.0**	**2.4**	**2.6**	**2.0**	**2.8**
	Top 10 Average	1.7	2.2	2.7	3.1	3.4	2.6	3.5
	Bottom 10 Average	0.9	1.2	1.4	1.7	1.8	1.4	2.2
11. Treasury Bond Yield, 30-Yr	**CONSENSUS**	**2.1**	**2.4**	**2.8**	**3.1**	**3.4**	**2.8**	**3.6**
	Top 10 Average	2.5	3.0	3.5	4.0	4.2	3.4	4.3
	Bottom 10 Average	1.6	1.9	2.2	2.4	2.6	2.1	2.9
12. Corporate Aaa Bond Yield	**CONSENSUS**	**2.8**	**3.2**	**3.6**	**4.0**	**4.2**	**3.6**	**4.5**
	Top 10 Average	3.1	3.6	4.2	4.6	4.9	4.1	5.0
	Bottom 10 Average	2.4	2.8	3.0	3.3	3.6	3.0	3.9
13. Corporate Baa Bond Yield	**CONSENSUS**	**3.9**	**4.3**	**4.7**	**5.0**	**5.2**	**4.6**	**5.4**
	Top 10 Average	4.3	4.7	5.2	5.6	5.9	5.1	6.0
	Bottom 10 Average	3.5	3.9	4.1	4.3	4.5	4.1	4.9
14. State & Local Bonds Yield	**CONSENSUS**	**2.8**	**3.1**	**3.4**	**3.6**	**3.8**	**3.3**	**3.9**
	Top 10 Average	3.1	3.5	3.8	4.1	4.3	3.8	4.3
	Bottom 10 Average	2.5	2.8	2.9	3.2	3.4	2.9	3.6
15. Home Mortgage Rate	**CONSENSUS**	**3.2**	**3.5**	**3.9**	**4.2**	**4.5**	**3.9**	**4.7**
	Top 10 Average	3.5	3.9	4.4	4.9	5.2	4.4	5.2
	Bottom 10 Average	2.9	3.2	3.4	3.6	3.8	3.4	4.2
A. Fed's AFE Nominal $ Index	**CONSENSUS**	**107.2**	**107.0**	**106.5**	**106.4**	**106.6**	**106.7**	**106.7**
	Top 10 Average	109.0	108.9	108.8	108.9	109.5	109.0	110.2
	Bottom 10 Average	105.4	105.2	104.4	103.8	103.7	104.5	103.0

		Year-Over-Year, % Change					Five-Year Averages	
		2022	2023	2024	2025	2026	2022-2026	2027-2031
B. Real GDP	**CONSENSUS**	**3.2**	**2.5**	**2.3**	**2.2**	**2.1**	**2.4**	**2.1**
	Top 10 Average	3.8	3.0	2.6	2.5	2.4	2.9	2.4
	Bottom 10 Average	2.6	2.1	1.9	1.9	1.8	2.1	1.8
C. GDP Chained Price Index	**CONSENSUS**	**1.9**	**2.0**	**2.1**	**2.1**	**2.1**	**2.0**	**2.1**
	Top 10 Average	2.2	2.3	2.3	2.3	2.3	2.3	2.3
	Bottom 10 Average	1.7	1.8	1.9	1.9	1.9	1.8	1.9
D. Consumer Price Index	**CONSENSUS**	**2.1**	**2.2**	**2.2**	**2.1**	**2.2**	**2.1**	**2.2**
	Top 10 Average	2.4	2.4	2.4	2.4	2.4	2.4	2.4
	Bottom 10 Average	1.8	1.9	1.9	1.9	1.9	1.9	1.9
E. PCE Price Index	**CONSENSUS**	**1.9**	**2.0**	**2.1**	**2.1**	**2.1**	**2.0**	**2.1**
	Top 10 Average	2.2	2.2	2.2	2.2	2.3	2.2	2.4
	Bottom 10 Average	1.7	1.8	1.9	1.9	1.9	1.8	1.9

Duke Energy Kentucky, Inc.
Derivation of Mean Equity Risk Premium Based Studies
Using Holding Period Returns and
Projected Market Appreciation of the S&P Utility Index

Line No.		Implied Equity Risk Premium
	Equity Risk Premium based on S&P Utility Index Holding Period Returns (1):	
1.	Historical Equity Risk Premium	4.16 %
2.	Regression of Historical Equity Risk Premium (2)	6.45
3.	Forecasted Equity Risk Premium Based on PRPM (3)	4.77
4.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Value Line Data) (4)	6.75
5.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Bloomberg Data) (5)	5.72
6.	Average Equity Risk Premium (6)	5.57 %

Notes: (1) Based on S&P Public Utility Index monthly total returns and Moody's Public Utility Bond average monthly yields from 1928-2020. Holding period returns are calculated based upon income received (dividends and interest) plus the relative change in the market value of a security over a one-year holding period.

(2) This equity risk premium is based on a regression of the monthly equity risk premiums of the S&P Utility Index relative to Moody's A2 rated public utility bond yields from 1928 - 2020 referenced in note 1 above.

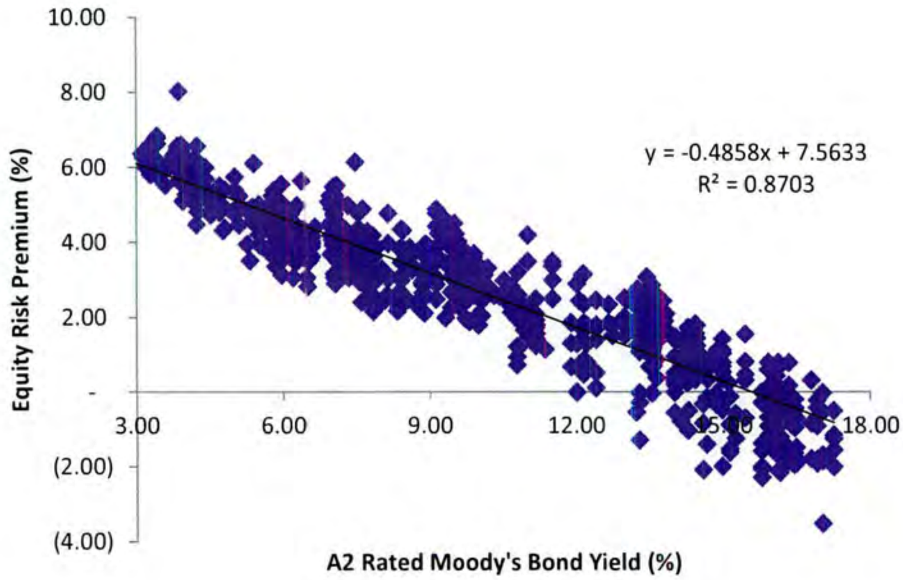
(3) The Predictive Risk Premium Model (PRPM) is applied to the risk premium of the monthly total returns of the S&P Utility Index and the monthly yields on Moody's A2 rated public utility bonds from January 1928 - March 2021.

(4) Using data from Value Line for the S&P Utilities Index, an expected return of 10.61% was derived based on expected dividend yields and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 3.86%, calculated on line 3 of page 3 of this Attachment results in an equity risk premium of 6.75%. (10.61% - 3.86% = 6.75%)

(5) Using data from Bloomberg Professional Service for the S&P Utilities Index, an expected return of 9.58% was derived based on expected dividend yields and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 3.86%, calculated on line 3 of page 3 of this Attachment results in an equity risk premium of 5.72%. (9.58% - 3.86% = 5.72%)

(6) Average of lines 1 through 5.

Duke Energy Kentucky, Inc.
Prediction of Equity Risk Premiums Relative to
Moody's A2 Rated Utility Bond Yields



Constant	Slope	Prospective A2 Rated Utility Bond (1)	Prospective Equity Risk Premium
7.563324 %	-0.48579	3.86 %	5.69 %

Notes:
(1) From line 3 of page 3 of this Attachment.

Source of Information:
Regulatory Research Associates
Bloomberg Professional Services

Duke Energy Kentucky, Inc.
Indicated Common Equity Cost Rate Through Use
of the Traditional Capital Asset Pricing Model (CAPM) and Empirical Capital Asset Pricing Model (ECAPM)

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Seven Natural Gas Distribution Companies	Value Line Adjusted Beta	Bloomberg Adjusted Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Atmos Energy Corporation	0.80	0.91	0.85	9.54 %	2.73 %	10.84 %	11.20 %	11.02 %
New Jersey Resources Corporation	0.95	0.96	0.96	9.54	2.73	11.89	11.99	11.94
Northwest Natural Holding Company	0.80	0.83	0.82	9.54	2.73	10.55	10.98	10.77
ONE Gas, Inc.	0.80	0.99	0.90	9.54	2.73	11.32	11.56	11.44
South Jersey Industries, Inc.	1.05	0.97	1.01	9.54	2.73	12.37	12.34	12.36
Southwest Gas Holdings, Inc.	0.95	1.07	1.01	9.54	2.73	12.37	12.34	12.36
Spire Inc.	0.85	0.99	0.92	9.54	2.73	11.51	11.70	11.60
Mean			0.92			11.55 %	11.73 %	11.64 %
Median			0.92			11.51 %	11.70 %	11.60 %
Average of Mean and Median			0.92			11.53 %	11.72 %	11.62 %

Notes on page 2 of this Attachment.

Duke Energy Kentucky, Inc.
Notes to Accompany the Application of the CAPM and ECAPM

Notes:

(1) The market risk premium (MRP) is derived by using six different measures from three sources: Ibbotson, Value Line, and Bloomberg as illustrated below:

Historical Data MRP Estimates:

Measure 1: Ibbotson Arithmetic Mean MRP (1926-2020)

Arithmetic Mean Monthly Returns for Large Stocks 1926-2020:	12.20 %
Arithmetic Mean Income Returns on Long-Term Government Bonds:	5.05
MRP based on Ibbotson Historical Data:	7.15 %

Measure 2: Application of a Regression Analysis to Ibbotson Historical Data (1926-2020) — 9.54 %

Measure 3: Application of the PRPM to Ibbotson Historical Data: (January 1926 - March 2021) — 10.46 %

Value Line MRP Estimates:

Measure 4: Value Line Projected MRP (Thirteen weeks ending April 02, 2021)

Total projected return on the market 3-5 years hence*:	8.47 %
Projected Risk-Free Rate (see note 2):	2.73
MRP based on Value Line Summary & Index	5.74 %

*Forcasted 3-5 year capital appreciation plus expected dividend yield

Measure 5: Value Line Projected Return on the Market based on the S&P 500

Total return on the Market based on the S&P 500:	14.21 %
Projected Risk-Free Rate (see note 2):	2.73
MRP based on Value Line data	11.48 %

Measure 6: Bloomberg Projected MRP

Total return on the Market based on the S&P 500:	15.61 %
Projected Risk-Free Rate (see note 2):	2.73
MRP based on Bloomberg data	12.88 %
Average of Value Line, Ibbotson, and Bloomberg MRP:	9.54 %

(2) For reasons explained in the direct testimony, the appropriate risk-free rate for cost of capital purposes is the average forecast of 30 year Treasury Bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts. (See pages 10 and 11 of Attachment DWD-3.) The projection of the risk-free rate is illustrated below:

Second Quarter 2021	2.40 %
Third Quarter 2021	2.50
Fourth Quarter 2021	2.50
First Quarter 2022	2.60
Second Quarter 2022	2.70
Third Quarter 2022	2.70
2022-2026	2.80
2027-2031	3.60
	2.73 %

(3) Average of Column 6 and Column 7.

Sources of Information:
Value Line Summary and Index
Blue Chip Financial Forecasts, April 1, 2021 and December 1, 2020
Stocks, Bonds, Bills, and Inflation - 2020 SBBI Yearbook, John Wiley & Sons, Inc.
Bloomberg Professional Services

Duke Energy Kentucky, Inc.
Basis of Selection of the Group of Non-Price Regulated Companies
Comparable in Total Risk to the Utility Proxy Group

The criteria for selection of the proxy group of forty-eight non-price regulated companies was that the non-price regulated companies be domestic and reported in Value Line Investment Survey (Standard Edition).

The Non-Price Regulated Proxy Group were then selected based on the unadjusted beta range of 0.64 – 0.94 and residual standard error of the regression range of 2.7297 – 3.2557 of the Utility Proxy Group.

These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression. Plus or minus two standard deviations captures 95.50% of the distribution of unadjusted betas and residual standard errors of the regression.

The standard deviation of the Utility Proxy Group's residual standard error of the regression is 0.1315. The standard deviation of the standard error of the regression is calculated as follows:

$$\text{Standard Deviation of the Std. Err. of the Regr.} = \frac{\text{Standard Error of the Regression}}{\sqrt{2N}}$$

where: N = number of observations. Since Value Line betas are derived from weekly price change observations over a period of five years, N = 259

$$\text{Thus, } 0.1315 = \frac{2.9927}{\sqrt{518}} = \frac{2.9927}{22.7596}$$

Source of Information: Value Line, Inc., March 2021
Value Line Investment Survey (Standard Edition)

Duke Energy Kentucky, Inc.
Basis of Selection of Comparable Risk
Domestic Non-Price Regulated Companies

	[1]	[2]	[3]	[4]
Proxy Group of Seven Natural Gas Distribution Companies	Value Line Adjusted Beta	Unadjusted Beta	Residual Standard Error of the Regression	Standard Deviation of Beta
Atmos Energy Corporation	0.80	0.66	2.7453	0.0685
New Jersey Resources Corporation	0.95	0.92	3.0205	0.0754
Northwest Natural Holding Company	0.80	0.69	3.1454	0.0785
ONE Gas, Inc.	0.80	0.67	2.7077	0.0676
South Jersey Industries, Inc.	1.05	1.00	3.4767	0.0868
Southwest Gas Holdings, Inc.	0.95	0.88	3.0244	0.0755
Spire Inc.	0.85	0.71	2.8287	0.0706
Average	0.89	0.79	2.9927	0.0747

Beta Range (+/- 2 std. Devs. of Beta)	0.64	0.94
2 std. Devs. of Beta	0.15	
Residual Std. Err. Range (+/- 2 std. Devs. of the Residual Std. Err.)	2.7297	3.2557
Std. dev. of the Res. Std. Err.	0.1315	
2 std. devs. of the Res. Std. Err.	0.2630	

Source of Information: Valueline Proprietary Database, March 2021

Duke Energy Kentucky, Inc.
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]
Proxy Group of Forty-Eight Non-Price Regulated Companies	VL Adjusted Beta	Unadjusted Beta	Residual Standard Error of the Regression	Standard Deviation of Beta
Apple Inc.	0.90	0.81	3.1746	0.0792
Abbott Labs.	0.95	0.88	2.7401	0.0684
Assurant Inc.	0.90	0.84	2.9537	0.0737
ANSYS, Inc.	0.85	0.74	2.8841	0.0720
Booz Allen Hamilton	0.90	0.82	3.0468	0.0760
Becton, Dickinson	0.80	0.66	2.8952	0.0722
Brown-Forman 'B'	0.90	0.77	2.7453	0.0685
Broadridge Fin'l	0.85	0.70	2.7332	0.0682
Brady Corp.	1.00	0.93	3.0007	0.0749
CACI Int'l	0.95	0.86	3.1684	0.0791
Casey's Gen'l Stores	0.90	0.78	3.2522	0.0812
Cadence Design Sys.	0.90	0.79	3.0338	0.0757
Cerner Corp.	0.90	0.84	2.7309	0.0681
CSW Industrials	0.90	0.81	2.8884	0.0721
Quest Diagnostics	0.85	0.75	2.7411	0.0684
Lauder (Estee)	0.95	0.85	2.8216	0.0704
Exponent, Inc.	0.90	0.79	2.9131	0.0727
Fastenal Co.	0.90	0.85	3.2203	0.0804
Gentex Corp.	0.95	0.91	2.7546	0.0687
Int'l Flavors & Frag	0.95	0.87	3.2238	0.0804
Ingredion Inc.	0.90	0.78	2.8793	0.0718
Iron Mountain	0.90	0.82	3.0897	0.0771
Hunt (J.B.)	0.95	0.86	2.8344	0.0707
J&J Snack Foods	0.90	0.84	2.9208	0.0729
Henry (Jack) & Assoc	0.85	0.71	2.7734	0.0692
ManTech Int'l 'A'	0.85	0.77	3.0653	0.0765
McCormick & Co.	0.80	0.66	2.7887	0.0696
Altria Group	0.90	0.83	2.9215	0.0729
MSA Safety	1.00	0.94	3.0076	0.0750
MSCI Inc.	0.95	0.87	2.9662	0.0740
Motorola Solutions	0.90	0.80	2.7926	0.0697
Vail Resorts	0.95	0.88	3.1939	0.0797
Maxim Integrated	0.95	0.87	2.9404	0.0734
Northrop Grumman	0.85	0.71	2.9032	0.0724
Old Dominion Freight	0.90	0.83	3.0708	0.0766
PerkinElmer Inc.	0.95	0.86	2.8896	0.0721
Philip Morris Int'l	0.95	0.88	3.2481	0.0811
Pool Corp.	0.85	0.75	3.2001	0.0799
Post Holdings	0.95	0.86	3.0105	0.0751
RLI Corp.	0.80	0.64	2.9883	0.0746
Rollins, Inc.	0.85	0.73	2.9697	0.0741
Selective Ins. Group	0.85	0.77	3.0004	0.0749
Sirius XM Holdings	0.95	0.91	2.7995	0.0699
Bio-Techne Corp.	0.80	0.67	3.2475	0.0810
Tetra Tech	0.90	0.84	3.0245	0.0755
Waters Corp.	0.95	0.86	2.7531	0.0687
West Pharmac. Svcs.	0.85	0.70	3.1887	0.0796
Western Union	0.80	0.67	2.7346	0.0682
Average	0.90	0.80	2.9609	0.0739
Proxy Group of Seven Natural Gas Distribution Companies	0.89	0.79	2.9927	0.0747

Source of Information: Valueline Proprietary Database, March 2021

Duke Energy Kentucky, Inc.
Summary of Cost of Equity Models Applied to
Proxy Group of Forty-Eight Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Distribution Companies

Principal Methods	Proxy Group of Forty-Eight Non-Price Regulated Companies
Discounted Cash Flow Model (DCF) (1)	12.60 %
Risk Premium Model (RPM) (2)	12.35
Capital Asset Pricing Model (CAPM) (3)	11.59
	12.18 %
	12.35 %
	12.27 %

Notes:
(1) From page 2 of this Attachment.
(2) From page 3 of this Attachment.
(3) From page 6 of this Attachment.

Duke Energy Kentucky, Inc.
DCF Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Distribution Companies

Proxy Group of Forty-Eight Non-Price Regulated Companies	[1] Average Dividend Yield	[2] Value Line Projected Five Year Growth in EPS	[3] Zack's Five Year Projected Growth Rate in EPS	[4] Bloomberg's Five Year Projected Growth Rate in EPS	[5] Yahoo! Finance Projected Five Year Growth in EPS	[6] Average Projected Five Year Growth Rate in EPS	[7] Adjusted Dividend Yield	[8] Indicated Common Equity Cost Rate (1)
Apple Inc.	0.64 %	14.50 %	11.00 %	9.50 %	14.69 %	12.42 %	0.68 %	13.10 %
Abbott Labs.	1.52	12.00	14.00	14.20	15.58	13.94	1.63	15.57
Assurant Inc.	1.96	11.50	NA	NA	19.40	15.45	2.11	17.56
ANSYS, Inc.	-	10.00	NA	12.05	8.00	10.02	-	NA
Booz Allen Hamilton	1.76	12.50	10.60	NA	10.99	11.36	1.86	13.22
Becton, Dickinson	1.33	9.00	9.00	9.54	12.00	9.88	1.40	11.28
Brown-Forman 'B'	0.98	12.00	NA	5.39	7.53	8.31	1.02	9.33
Broadridge Fin'l	1.56	10.50	NA	10.70	10.00	10.40	1.64	12.04
Brady Corp.	1.68	8.00	7.00	7.33	7.00	7.33	1.74	9.07
CACI Int'l	-	14.00	10.50	10.53	12.91	11.99	-	NA
Casey's Gen'l Stores	0.68	9.00	NA	15.81	7.85	10.89	0.72	11.61
Cadence Design Sys.	-	13.00	11.10	11.90	11.10	11.78	-	NA
Cerner Corp.	1.17	8.00	12.30	8.61	11.51	10.11	1.23	11.34
CSW Industrials	0.42	8.50	NA	NA	12.00	10.25	0.44	10.69
Quest Diagnostics	2.01	10.00	26.50	(6.93)	9.22	15.24	2.16	17.40
Lauder (Estee)	0.77	11.00	10.70	17.23	21.10	15.01	0.83	15.84
Exponent, Inc.	0.85	12.00	NA	13.30	15.00	13.43	0.91	14.34
Fastenal Co.	2.34	8.00	9.00	10.15	8.04	8.80	2.44	11.24
Gentex Corp.	1.35	10.50	4.70	10.25	15.80	10.31	1.42	11.73
Int'l Flavors & Frag	2.37	6.50	10.00	21.05	10.00	11.89	2.51	14.40
Ingredion Inc.	2.99	6.00	NA	11.00	1.90	6.30	3.08	9.38
Iron Mountain	7.38	7.50	1.70	4.00	1.70	3.73	7.52	11.25
Hunt (J.B.)	0.74	6.50	15.00	17.23	20.73	14.87	0.80	15.67
J&J Snack Foods	1.47	10.00	NA	NA	6.00	8.00	1.53	9.53
Henry (Jack) & Assoc	1.21	10.50	10.90	12.47	10.02	10.97	1.28	12.25
ManTech Int'l 'A'	1.74	12.00	5.10	5.06	4.53	6.67	1.80	8.47
McCormick & Co.	1.53	6.50	6.60	5.82	5.50	6.11	1.58	7.69
Altria Group	7.66	6.50	4.00	2.70	4.42	4.41	7.83	12.24
MSA Safety	1.07	6.50	NA	9.00	18.00	11.17	1.13	12.30
MSCI Inc.	0.74	18.00	NA	12.20	14.37	14.86	0.79	15.65
Motorola Solutions	1.59	7.00	9.00	11.30	5.88	8.30	1.66	9.96
Vail Resorts	-	8.50	NA	86.86	69.80	55.05	-	NA
Maxim Integrated	-	8.00	10.00	11.30	18.44	11.94	-	NA
Northrop Grumman	1.92	7.00	NA	4.96	5.44	5.80	1.98	7.78
Old Dominion Freight	0.37	9.00	15.30	16.18	15.89	14.09	0.40	14.49
PerkinElmer Inc.	0.20	17.50	19.50	(6.87)	17.20	18.07	0.22	18.29
Philip Morris Int'l	5.65	5.00	8.30	10.39	11.42	8.78	5.90	14.68
Pool Corp.	0.67	17.50	NA	17.00	17.00	17.17	0.73	17.90
Post Holdings	-	11.50	NA	20.30	31.20	21.00	-	NA
RLI Corp.	0.90	12.50	NA	NA	9.80	11.15	0.95	12.10
Rollins, Inc.	0.89	11.50	NA	NA	8.20	9.85	0.93	10.78
Selective Ins. Group	1.44	8.50	NA	NA	5.10	6.80	1.49	8.29
Sirius XM Holdings	0.96	24.50	14.80	26.96	12.93	19.80	1.06	20.86
Bio-Techne Corp.	0.35	12.50	15.00	19.03	15.00	15.38	0.38	15.76
Tetra Tech	0.51	13.50	15.00	13.85	15.00	14.34	0.55	14.89
Waters Corp.	-	6.00	8.80	9.03	7.17	7.75	-	NA
West Pharmac. Svcs.	0.24	17.00	22.60	17.21	22.60	19.85	0.26	20.11
Western Union	3.99	6.00	NA	4.57	9.25	6.61	4.12	10.73
							Mean	12.95 %
							Median	12.24 %
						Average of Mean and Median		12.60 %

NA= Not Available
NMF= Not Meaningful Figure

(1) The application of the DCF model to the domestic, non-price regluated comparable risk companies is identical to the application of the DCF to the Utility Proxy Group. The dividend yield is derived by using the 60 day average price and the spot indicated dividend as of March 31, 2021. The dividend yield is then adjusted by 1/2 the average projected growth rate in EPS, which is calculated by averaging the 5 year projected growth in EPS provided by Value Line, www.zacks.com, Bloomberg Professional Services, and www.yahoo.com (excluding any negative growth rates) and then adding that growth rate to the adjusted dividend yield.

Source of Information: Value Line Investment Survey
www.zacks.com Downloaded on 03/31/2021
www.yahoo.com Downloaded on 03/31/2021
Bloomberg Professional Services

Duke Energy Kentucky, Inc.
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Forty-Eight Non-Price Regulated Companies
1.	Prospective Yield on Baa2 Rated Corporate Bonds (1)	4.36 %
2.	Equity Risk Premium (2)	7.99
3.	Risk Premium Derived Common Equity Cost Rate	12.35 %

Notes: (1) Average forecast of Baa2 corporate bonds based upon the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated April 1, 2021 and December 1, 2020 (see pages 10 and 11 of Attachment DWD-3). The estimates are detailed below.

Second Quarter 2021	3.90 %
Third Quarter 2021	4.00
Fourth Quarter 2021	4.10
First Quarter 2022	4.20
Second Quarter 2022	4.30
Third Quarter 2022	4.40
2022-2026	4.60
2027-2031	5.40
Average	4.36 %

(2) From page 5 of this Attachment.

Duke Energy Kentucky, Inc.
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Forty-Eight Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Seven Natural Gas Distribution Companies

	Moody's Long-Term Issuer Rating March 2021		Standard & Poor's Long-Term Issuer Rating March 2021	
Proxy Group of Forty-Eight Non-Price Regulated Companies	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
Apple Inc.	Aa1	2.0	AA+	2.0
Abbott Labs.	A3	7.0	A	6.0
Assurant Inc.	Baa3	10.0	BBB	9.0
ANSYS, Inc.	NA	--	NA	--
Booz Allen Hamilton	NA	--	NA	--
Becton, Dickinson	Baa3	10.0	BBB	9.0
Brown-Forman 'B'	A1	5.0	A-	7.0
Broadridge Fin'l	Baa1	8.0	BBB+	8.0
Brady Corp.	NA	--	NA	--
CACI Int'l	NA	--	BB+	11.0
Casey's Gen'l Stores	NA	--	NA	--
Cadence Design Sys.	Baa2	9.0	BBB+	8.0
Cerner Corp.	NA	--	NA	--
CSW Industrials	NA	--	NA	--
Quest Diagnostics	Baa2	9.0	BBB+	8.0
Lauder (Estee)	A1	5.0	A+	5.0
Exponent, Inc.	NA	--	NA	--
Fastenal Co.	NA	--	NA	--
Gentex Corp.	NA	--	NA	--
Int'l Flavors & Frag	Baa3	10.0	BBB	9.0
Ingredion Inc.	Baa1	8.0	BBB	9.0
Iron Mountain	Ba3	13.0	BB-	13.0
Hunt (J.B.)	Baa1	8.0	BBB+	8.0
J&J Snack Foods	NA	--	NA	--
Henry (Jack) & Assoc	NA	--	NA	--
ManTech Int'l 'A'	WR	--	BB+	11.0
McCormick & Co.	Baa2	9.0	BBB	9.0
Altria Group	A3	7.0	BBB	9.0
MSA Safety	NA	--	NA	--
MSCI Inc.	Ba2	12.0	BB+	11.0
Motorola Solutions	Baa3	10.0	BBB-	10.0
Vail Resorts	B2	15.0	BB	12.0
Maxim Integrated	Baa1	8.0	BBB+	8.0
Northrop Grumman	Baa2	9.0	BBB+	8.0
Old Dominion Freight	NA	--	NA	--
PerkinElmer Inc.	Baa3	10.0	BBB	9.0
Philip Morris Int'l	A2	6.0	A	6.0
Pool Corp.	NA	--	NA	--
Post Holdings	B2	15.0	B+	14.0
RLI Corp.	Baa2	9.0	BBB+	8.0
Rollins, Inc.	NA	--	NA	--
Selective Ins. Group	Baa2	9.0	BBB	9.0
Sirius XM Holdings	NA	--	BB	12.0
Bio-Techne Corp.	NA	--	NA	--
Tetra Tech	NA	--	NA	--
Waters Corp.	NA	--	NA	--
West Pharmac. Svcs.	NA	--	NA	--
Western Union	Baa2	9.0	BBB	9.0
Average	Baa2	8.9	BBB	8.9

Notes:
(1) From page 6 of Attachment DWD-3.

Source of Information:
Bloomberg Professional Services

Duke Energy Kentucky, Inc.
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for
Proxy Group of Forty-Eight Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Seven Natural Gas Distribution Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Forty-Eight Non-Price Regulated Companies
	Ibbotson-Based Equity Risk Premiums:	
1.	Ibbotson Equity Risk Premium (1)	5.92 %
2.	Regression on Ibbotson Risk Premium Data (2)	8.83
3.	Ibbotson Equity Risk Premium based on PRPM (3)	9.40
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	5.03
5	Equity Risk Premium Based on Value Line S&P 500 Companies (5)	10.77
6.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	12.17
7.	Conclusion of Equity Risk Premium	8.69 %
8.	Adjusted Beta (7)	0.92
9.	Forecasted Equity Risk Premium	7.99 %

Notes:

(1) From note 1 of page 9 of Attachment DWD-3.
(2) From note 2 of page 9 of Attachment DWD-3.
(3) From note 3 of page 9 of Attachment DWD-3.
(4) From note 4 of page 9 of Attachment DWD-3.
(5) From note 5 of page 9 of Attachment DWD-3.
(6) From note 6 of page 9 of Attachment DWD-3.
(7) Average of mean and median beta from page 6 of this Attachment.

Sources of Information:

Stocks, Bonds, Bills, and Inflation - 2020 SBBI Yearbook, John Wiley & Sons, Inc.
Value Line Summary and Index
Blue Chip Financial Forecasts, April 1, 2021 and December 1, 2020
Bloomberg Professional Services

Duke Energy Kentucky, Inc.
Traditional CAPM and ECAPM Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Forty-Eight Non-Price Regulated Companies	Value Line Adjusted Beta	Bloomberg Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Apple Inc.	0.90	1.02	0.96	9.54 %	2.73 %	11.89 %	11.99 %	11.94 %
Abbott Labs.	0.95	0.86	0.90	9.54	2.73	11.32	11.56	11.44
Assurant Inc.	0.95	0.98	0.97	9.54	2.73	11.99	12.06	12.02
ANSYS, Inc.	0.85	0.97	0.91	9.54	2.73	11.41	11.63	11.52
Booz Allen Hamilton	0.90	0.90	0.90	9.54	2.73	11.32	11.56	11.44
Becton, Dickinson	0.80	0.59	0.69	9.54	2.73	9.31	10.05	9.68
Brown-Forman 'B'	0.85	0.98	0.92	9.54	2.73	11.51	11.70	11.60
Broadridge Fin'l	0.85	0.83	0.84	9.54	2.73	10.75	11.13	10.94
Brady Corp.	1.00	1.05	1.03	9.54	2.73	12.56	12.49	12.52
CACI Int'l	0.95	1.00	0.97	9.54	2.73	11.99	12.06	12.02
Casey's Gen'l Stores	0.85	0.91	0.88	9.54	2.73	11.13	11.41	11.27
Cadence Design Sys.	0.90	0.98	0.94	9.54	2.73	11.70	11.84	11.77
Cerner Corp.	0.90	0.89	0.89	9.54	2.73	11.22	11.48	11.35
CSW Industrials	0.85	1.03	0.94	9.54	2.73	11.70	11.84	11.77
Quest Diagnostics	0.85	0.96	0.91	9.54	2.73	11.41	11.63	11.52
Lauder (Estee)	0.95	1.01	0.98	9.54	2.73	12.08	12.13	12.10
Exponent, Inc.	0.90	0.94	0.92	9.54	2.73	11.51	11.70	11.60
Fastenal Co.	0.90	0.97	0.93	9.54	2.73	11.60	11.77	11.69
Gentex Corp.	0.95	1.07	1.01	9.54	2.73	12.37	12.34	12.36
Int'l Flavors & Frag	0.95	1.08	1.01	9.54	2.73	12.37	12.34	12.36
Ingredion Inc.	0.90	0.93	0.91	9.54	2.73	11.41	11.63	11.52
Iron Mountain	0.90	1.02	0.96	9.54	2.73	11.89	11.99	11.94
Hunt (J.B.)	0.95	0.92	0.94	9.54	2.73	11.70	11.84	11.77
J&J Snack Foods	0.90	0.77	0.84	9.54	2.73	10.75	11.13	10.94
Henry (Jack) & Assoc	0.85	0.89	0.87	9.54	2.73	11.03	11.34	11.19
ManTech Int'l 'A'	0.85	1.12	0.99	9.54	2.73	12.18	12.20	12.19
McCormick & Co.	0.85	0.69	0.77	9.54	2.73	10.08	10.63	10.35
Altria Group	0.90	0.89	0.89	9.54	2.73	11.22	11.48	11.35
MSA Safety	1.00	1.00	1.00	9.54	2.73	12.27	12.27	12.27
MSCI Inc.	0.95	0.93	0.94	9.54	2.73	11.70	11.84	11.77
Motorola Solutions	0.90	0.95	0.92	9.54	2.73	11.51	11.70	11.60
Vail Resorts	0.90	1.15	1.02	9.54	2.73	12.46	12.41	12.44
Maxim Integrated	0.95	1.00	0.97	9.54	2.73	11.99	12.06	12.02
Northrop Grumman	0.85	0.79	0.82	9.54	2.73	10.55	10.98	10.77
Old Dominion Freight	0.90	0.98	0.94	9.54	2.73	11.70	11.84	11.77
PerkinElmer Inc.	0.95	0.84	0.90	9.54	2.73	11.32	11.56	11.44
Philip Morris Int'l	0.95	0.92	0.94	9.54	2.73	11.70	11.84	11.77
Pool Corp.	0.90	0.94	0.92	9.54	2.73	11.51	11.70	11.60
Post Holdings	0.95	0.90	0.92	9.54	2.73	11.51	11.70	11.60
RLI Corp.	0.80	0.89	0.84	9.54	2.73	10.75	11.13	10.94
Rollins, Inc.	0.85	0.69	0.77	9.54	2.73	10.08	10.63	10.35
Selective Ins. Group	0.85	0.96	0.91	9.54	2.73	11.41	11.63	11.52
Sirius XM Holdings	1.00	1.10	1.05	9.54	2.73	12.75	12.63	12.69
Bio-Techne Corp.	0.80	0.92	0.86	9.54	2.73	10.94	11.27	11.10
Tetra Tech	0.90	1.05	0.98	9.54	2.73	12.08	12.13	12.10
Waters Corp.	0.95	0.85	0.90	9.54	2.73	11.32	11.56	11.44
West Pharmac. Svcs.	0.85	0.76	0.80	9.54	2.73	10.36	10.84	10.60
Western Union	0.80	1.05	0.92	9.54	2.73	11.51	11.70	11.60
		Mean	0.92			11.47 %	11.67 %	11.57 %
		Median	0.92			11.51 %	11.70 %	11.60 %
	Average of Mean and Median		0.92			11.49 %	11.69 %	11.59 %

Notes:
(1) From note 1 of page 2 of Attachment DWD-4.
(2) From note 2 of page 2 of Attachment DWD-4.
(3) Average of CAPM and ECAPM cost rates.

Duke Energy Kentucky, Inc.
Derivation of Investment Risk Adjustment Based upon
Ibbotson Associates' Size Premia for the Decile Portfolios of the NYSE/AMEX/NASDAQ

Line No.		[1] Market Capitalization on September 30, 2020 (1) (millions)	(times larger)	[2] Applicable Decile of the NYSE/AMEX/ NASDAQ (2)	[3] Applicable Size Premium (3)	[4] Spread from Applicable Size Premium (4)
1.	Duke Energy Kentucky, Inc.	$ 1,241.112		7	1.54%	
2.	Proxy Group of Seven Natural Gas Distribution Companies	$ 4,574.713	3.7 x	4	0.75%	0.79%

	[A] Decile	[B] Market Capitalization of Smallest Company (millions)	[C] Market Capitalization of Largest Company (millions)	[D] Size Premium (Return in Excess of CAPM)*
Largest	1	$ 29,025.803	$ 1,966,078.882	-0.22%
	2	13,178.743	28,808.073	0.49%
	3	6,743.361	13,177.828	0.71%
	4	3,861.858	6,710.676	0.75%
	5	2,445.693	3,836.536	1.09%
	6	1,591.865	2,444.745	1.37%
	7	911.586	1,591.765	1.54%
	8	451.955	911.103	1.46%
	9	190.019	451.800	2.29%
Smallest	10	2.194	189.831	5.01%

*From 2021 Duff & Phelps Cost of Capital Navigator

Notes:

(1) From page 2 of this Attachment.

(2) Gleaned from Columns [B] and [C] on the bottom of this page. The appropriate decile (Column [A]) corresponds to the market capitalization of the proxy group, which is found in Column [1].

(3) Corresponding risk premium to the decile is provided in Column [D] on the bottom of this page.

(4) Line No. 1 Column [3] – Line No. 2 Column [3]. For example, the 0.79% in Column [4], Line No. 2 is derived as follows 0.79% = 1.54% - 0.75%.

Duke Energy Kentucky, Inc.
Market Capitalization of Duke Energy Kentucky, Inc. and the
Proxy Group of Seven Natural Gas Distribution Companies

Company	Exchange	[1] Common Stock Shares Outstanding at Fiscal Year End 2020 (millions)	[2] Book Value per Share at Fiscal Year End 2020 (1)	[3] Total Common Equity at Fiscal Year End 2020 (millions)	[4] Closing Stock Market Price on March 31, 2021	[5] Market-to-Book Ratio on March 31, 2021 (2)	[6] Market Capitalization on March 31, 2021 (3) (millions)
Duke Energy Kentucky, Inc.		NA	NA	718.236 (4)	NA		
Based upon Proxy Group of Seven Natural Gas Distribution Companies						172.8 (5)	$ 1,241.112 (6)
Proxy Group of Seven Natural Gas Distribution Companies							
Atmos Energy Corporation	NYSE	$ 125.882	$ 53.949	$ 6,791.203	$ 98.850	183.2 %	$ 12,443.483
New Jersey Resources Corporation	NYSE	95.949	19.226	1,844.692	39.870	207.4	3,825.494
Northwest Natural Holding Company	NYSE	30.589	29.054	888.733	53.950	185.7	1,650.277
ONE Gas, Inc.	NYSE	53.167	42.006	2,233.311	76.910	183.1	4,089.053
South Jersey Industries, Inc.	NYSE	100.592	16.571	1,666.876	22.580	136.3	2,271.366
Southwest Gas Holdings, Inc.	NYSE	57.193	46.771	2,674.953	68.710	146.9	3,929.726
Spire Inc.	NYSE	51.612	44.182	2,280.300	73.890	167.2	3,813.595
Average		$ 73.569	$ 35.966	$ 2,625.724	$ 62.109	172.8 %	$ 4,574.713

NA= Not Available

Notes: (1) Column 3 / Column 1.
(2) Column 4 / Column 2.
(3) Column 1 * Column 4.
(4) Requested rate base multiplied by the requested common equity ratio.
(5) The market-to-book ratio of Duke Energy Kentucky, Inc. on March 31, 2021 is assumed to be equal to the market-to-book ratio of Proxy Group of Seven Natural Gas Distribution Companies on March 31, 2021 as appropriate.
(6) Column [3] multiplied by Column [5].

Source of Information: 2020 Annual Forms 10K
yahoo.finance.com
Bloomberg Professional

Duke Energy Kentucky, Inc.
Derivation of the Flotation Cost Adjustment to the Cost of Common Equity

Equity Issuances since 2010

Date of Offering	Transaction (1)	[Column 1] Shares Issued	[Column 2] Market Price per Share	[Column 3] Average Offering Price per Share	[Column 4] Market Pressure (2)	[Column 5] Total Offering Expense per Share	[Column 6] Net Proceeds per Share (3)	[Column 7] Gross Equity Issue before Costs (4)	[Column 8] Total Net Proceeds (5)	[Column 9] Total Flotation Costs (6)	[Column 10] Flotation Cost Percentage (7)
11/18/19	Equity Offering	28,750,000	$ 88.65	$ 85.99	$ 2.66	$ 0.021	$ 85.9694	$ 2,548,687,500	$ 2,471,620,500	$ 77,067,000	3.02%
03/06/18	Equity Offering	21,275,000	$ 75.86	$ 74.07	$ 1.79	$ 0.021	$ 74.0508	$ 1,613,921,500	$ 1,575,431,800	$ 38,489,700	2.38%
03/01/16	Equity Offering	10,637,500	$ 73.35	$ 69.84	$ 3.51	$ 0.038	$ 69.8024	$ 780,260,625	$ 742,523,000	$ 37,737,625	4.84%
								$ 4,942,869,625	$ 4,789,575,300	$ 153,294,325	3.10%

Flotation Cost Adjustment

	Average Dividend Yield	Average Projected EPS Growth Rate	Adjusted Dividend Yield	Average DCF Cost Rate Unadjusted for Flotation (8)	DCF Cost Rate Adjusted for Flotation (9)	Flotation Cost Adjustment (10)
Proxy Group of Seven Natural Gas Distribution Companies	3.74 %	5.94 %	3.85 %	9.79 %	9.91 %	0.12 %

See page 2 of this Attachment for notes.

Source of Information: Company SEC filings

Duke Energy Kentucky, Inc.
Notes to Accompany the
Derivation of the Flotation Cost Adjustment to the Cost of Common Equity

(1) Company-provided.

(2) Column 2 – Column 3.

(3) Column 2 – the sum of columns 4 and 5.

(4) Column 1 * Column 2.

(5) Column1 * Column 6.

(6) Column1 * (the sum of columns 4 and 5).

(7) (Column 7 – Column 8) divided by Column 7.

(8) Using the average growth rate from Attachment DWD-2.

(9) Adjustment for flotation costs based on adjusting the average DCF constant growth cost rate in accordance with the following:

$$K = \frac{D(1+0.5g)}{P(1-F)} + g,$$

where g is the growth factor and F is the percentage of flotation costs.

(10) Flotation cost adjustment of 0.12% equals the difference between the flotation adjusted average DCF cost rate of 9.91% and the unadjusted average DCF cost rate of 9.79% of the Utility Proxy Group.

Source of Information:

Company provided information

Summary of Adjustment Clauses & Alternative Regulation/Incentive Plans

			Adjustment Clauses					Alternative Regulation / Incentive Plans	
Company	Parent	State	Gas Commodity	Decoupling (F/P) [1]	Capital Investment [2]	Energy Efficiency [3]	Other [4]	Formula-Based Rates	Earnings Sharing/PBR
Atmos Energy	ATO	Colorado	✓		✓	✓	✓		
Atmos Energy	ATO	Kansas	✓	P	✓		✓		
Atmos Energy	ATO	Kentucky	✓	P	✓	✓			✓
Atmos Energy	ATO	Louisiana	✓	P	✓			✓	✓
Atmos Energy	ATO	Mississippi	✓	P	✓	✓	✓	✓	
Atmos Energy	ATO	Tennessee	✓	P	✓			✓	✓
Atmos Energy	ATO	Texas	✓	P	✓	✓	✓	✓	
Atmos Energy	ATO	Virginia	✓	P	✓				
New Jersey Natural Gas	NJR	New Jersey	✓	F	✓	✓	✓		
Northwest Natural Gas	NWN	Oregon	✓	P		✓	✓		
Northwest Natural Gas	NWN	Washington	✓			✓	✓		
Kansas Gas Service	OGS	Kansas	✓	P	✓		✓		
Oklahoma Natural Gas	OGS	Oklahoma	✓	P	✓	✓	✓	✓	✓
Texas Gas Service	OGS	Texas	✓	P	✓	✓	✓	✓	
Elizabethtown Gas	SJI	New Jersey	✓	P	✓	✓	✓		
South Jersey Gas	SJI	New Jersey	✓	F	✓	✓	✓		
Southwest Gas Corporation	SWX	Arizona	✓	F	✓	✓	✓		
Southwest Gas Corporation	SWX	California	✓	F	✓	✓	✓		
Southwest Gas Corporation	SWX	Nevada	✓	F	✓	✓	✓		
Alabama Gas Corporation	SR	Alabama	✓	P	✓		✓	✓	
Spire Gulf Inc. (Mobile Gas Corporation)	SR	Alabama	✓	P	✓		✓	✓	
Spire Missouri East	SR	Missouri	✓	P	✓		✓		
Spire Missouri West	SR	Missouri	✓	P	✓		✓		

Notes:

Note: A mechanism may cover one or more cost categories; therefore, designations may not indicate separate mechanisms for each category.

[1] Full or partial decoupling (such as Fixed Variable rate design, weather normalization clauses, and recovery of lost revenues as a result of Energy Efficiency programs). All full or partial decoupling mechanisms include weather normalization adjustments.

[2] Includes recovery of costs related to infrastructure replacement, system integrity/hardening, and other capital expenditures.

[3] Utility-sponsored conservation, energy efficiency, or other demand side management programs.

[4] Pension expenses, bad debt costs, storm costs, transmission/transportation costs, environmental, regulatory fee, government & franchise fees and taxes, economic development, and low income programs.

Sources: Operating company tariffs; Regulatory Research Associates, *Alternative Ratemaking Plans in the US*, April 16, 2020; Regulatory Research Associates, *Adjustment Clauses: A State-by-State Overview,* November 12, 2019; *Edison Electric Institute, Alternative Regulation for Emerging Utility Challenges: 2015 Update, November 11, 2015*.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Natural Gas Rates; 2) Approval of New Tariffs; and 3) All Other Required Approvals, Waivers, and Relief.	))))))	Case No. 2021-00190

DIRECT TESTIMONY OF

RETHA I. HUNSICKER

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

June 1, 2021

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PAGE

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Retha I. Hunsicker and my business address is 400 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 Vice-President Customer Connect-Solutions. DEBS provide 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 hold a Bachelor of Science degree in Business Administration from Indiana Wesleyan University. Since 1981, I have been employed by, and worked for, companies under what is now Duke Energy. I began my career with Public Service Indiana, the predecessor to Duke Energy Indiana, LLC, (Duke Energy Indiana) as an accounting assistant. Since then, I have held positions with increasing levels of responsibility. More recently, the roles I've held include Director, Business Standards and Integration, and General Manager, Smart Energy Systems & Processes. In 2012, I took the position of Regional Director, Customer Services, leading our Midwest contact centers, before promoting to Vice President, Customer Contact Operations in 2013. I assumed my current role as Vice President, Customer Connect-Solutions in 2015.

Q. PLEASE DESCRIBE YOUR DUTIES AS VICE PRESIDENT, CUSTOMER CONNECT-SOLUTIONS.

A. I have executive management oversight for the customer information system (CIS) consolidation project known as Customer Connect. Through this program, Duke Energy will complete the successful deployment of a new customer platform that will enable the functional capabilities needed to meet our strategic purpose of powering the lives of our customers by modernizing how we serve them.

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

A. Yes, I testified before the Kentucky Public Service Commission as a Company witness in Case No. 2019-00271.

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

A. The purpose of my testimony is to discuss the Company's current CIS and explain why it is necessary to convert that CIS into a modern customer service platform. I discuss the new enhancements that will be available to customers, as well as the features that have already been implemented. I also discuss the Revert-to-Owner program, which replaces the Company's current Automatic Landlord program.

II. DISCUSSION

Q. BRIEFLY DESCRIBE THE PURPOSE OF A CIS AND DUKE ENERGY KENTUCKY'S CURRENT CIS.

A. A CIS manages the billing, accounts receivable, and rates for the Company and is the central repository for all customer information. A CIS also manages customer profiles and integration of data to provide a holistic view of the customer. The CIS currently used by Duke Energy Kentucky was developed more than thirty years ago, beginning in 1987, and it was put in service in 1993. This CIS supports Duke Energy Kentucky, its parent, Duke Energy Ohio, Inc. and its sister utility, Duke Energy Indiana, LLC.

Although state-of-the-art nearly thirty years ago, the current CIS was not designed to efficiently support new capabilities, including personalized experiences for customers, advanced pricing structures and billing options, and tools for customers to better manage their energy consumption. The Company has added functions and new technologies to the legacy system to try to meet the evolving customer needs and expectations, and this adds complexity to the current system. The CIS has been modified over the years, with the first such modification occurring shortly after it was put in service, in 1999. And subsequent changes have been necessary in order to allow the Company to continue to adapt and serve our customer's growing expectations and needs.

Q. HOW HAS DUKE ENERGY KENTUCKY MODIFIED THE CURRENT SYSTEM?

A. The Company has continued to add functions to the legacy system to try to meet business needs. But as we add newer technologies to the legacy system, the complexity continues to increase, thereby leading to more system disruptions and longer time to recover from outages. In some cases, the business has started looking for other options to meet needs, resulting in disjointed solutions and causing us to leverage multiple vendors.

Q. PLEASE DESCRIBE THE LIMITATIONS OF THE CURRENT CIS.

A. The current CIS is a premises-based system, meaning it was developed to communicate with a meter attached to a premise, without regard to who may be consuming the services provided through the meter or how they may be consuming those services. For example, the current CIS does not allow the Company to maintain customer preferences through the life of their service when moving locations. Customer selections such as specific billing and payment programs and communication preferences often have to be re-established by the customer when moving from one location to another. With Customer Connect, the Company will maintain these customer preferences for the life of their service. Furthermore, such a restrictive system prevents Duke Energy Kentucky from interacting with customers in a meaningful and continually relevant manner. For instance, much of the company's customer base favors more modern communication channels, where information is almost immediately available;

however, the current CIS does not enable customers to employ their preferred channels, or methods, of communications.

Continued investment to modify an antiquated technology platform is not practical or sustainable. CISs, like any other software solution, are subject to obsolescence. Upgrades cannot remedy the problems encountered with obsolescence and, like other technology and software, must be made periodically to meet customer expectations.

Q. PLEASE DISCUSS HOW A MODERN CIS WILL BENEFIT DUKE ENERGY KENTUCKY'S CUSTOMERS.

A. Customer Connect is Duke Energy's enterprise-wide initiative that will transform the way the Company interacts with and serves customers, ensuring a universal, simple and consistent experience across channels. Many of the customer benefits from a modernized grid require new customer platform technologies that do not exist in the Company's current CIS, and the rapid pace and complexity of changes make it impossible to keep up by incremental modification of the existing CIS. The Customer Connect platform, Systems, Applications and Products in Data Processing (SAP), will have a billing and receivables system that will be aligned with the current market to enable efficient billing for customers that did not exist when the legacy customer information systems were built. And its integrated operational and analytics platform will aggregate and understand customer preferences and behaviors, and leverage that understanding to personalize customer experiences and serve our customers as individuals. It is the modernization we need, and the simplification customers deserve.

By consolidating the older CISs into a new CIS, Duke Energy and, in turn, Duke Energy Kentucky, will be able to deliver a simpler and more efficient customer experience. Key customer benefits include the following:

- Modern, Configurable Billing Engine – With the Company's existing CIS, many new rates are very time consuming and burdensome to implement due to the antiquated architecture of the system and the complexity of coding and testing the rates. In contrast, in the modern CIS, new rates will be configurable and much simpler to implement, improving the Company's responsiveness to regulatory or market changes.
- Customer-Centric Data Model – Customer Connect will have a customer-centric data model to enable a "one customer" view across Duke Energy. The Company will thus know the customer better and provide a more streamlined, personalized experience.
- Holistic Customer Profile – In the current CIS, systems merely store basic customer information – name, phone, address, premise and historical usage, billing and payment information – preventing us from knowing customers beyond these basic attributes. Customer Connect will store all of that same information and more. The new platform will gather all of the relevant touchpoints that customers have with Duke Energy in real time – web visits, phone calls, power outages, outbound communications, product and service participation, *etc.* – to

build out a holistic view of customers that can be leveraged to better serve them and personalize their experiences.

- Integrated Analytics – The integrated analytics capabilities of the new platform will then leverage this customer profile data to personalize experiences and better serve customers through every channel. For example, the new platform will predict the intent of customers when they call Duke Energy, thereby improving their experience in the interactive voice response unit (IVR) and routing them to the customer care specialist best suited to meet their needs. This same capability will be leveraged to prioritize what information is conveyed to the customer and convey that information in the medium preferred by the customer, whether it is via web, email or other channels, to ensure it is timely, relevant and valuable to him or her. These are just two examples of the multiple opportunities to leverage real-time analytics to improve our customers' everyday experiences with Duke Energy.
- Multi-Company – In the current CIS, customers exist as separate entities across jurisdictions. When a customer moves from one jurisdiction to another, all information about that customer is lost – account numbers, communication preferences, payment and credit history, product and service participation, *etc*. Customers do not understand why this happens and are frustrated by the experience. In the future, these types of account attributes will follow the customers

throughout their experience with Duke Energy as they move between locations and jurisdictions.

Q. WILL THE NEW SYSTEM ALLOW FOR MORE FLEXIBLE RATE DESIGN AND OTHER RATE OFFERINGS?

A. Yes, as mentioned above, the current CIS requires significant coding to implement new rates and pricing. New, modern CISs are much more configurable, reducing the amount of time to test and implement pricing changes and offerings.

Q. WILL CUSTOMERS SEE ANY BENEFITS PRIOR TO FULL DEPLOYMENT FOR DUKE ENERGY KENTUCKY?

A. Yes, the Company has deployed new capabilities to customers each year, 2018-2020, leading up to its full system deployments.

Q. PLEASE EXPLAIN WHAT HAS BEEN ACCOMPLISHED SO FAR AND WHAT CUSTOMERS CAN EXPECT AS THE NEW SYSTEM IS DEPLOYED.

A. In June 2018, the first deliverable of the Customer Connect Program was successfully deployed, which provided the capabilities to begin to gather, store and analyze customer insights to create more satisfying interactions. Specifically, the Company began gathering all relevant touchpoints that customers are having with Duke Energy in real-time such as web visits, phone calls, power outages, outbound communications, and product and service participation. As described throughout my testimony, the Company is working to better understand its customers so that we can serve them in the manner in which they have become accustomed, and this deliverable was the first step in doing that. The Company also delivered enhanced communication capabilities which provide more personalized service with automated and targeted campaigns. These capabilities automate processes, increase effectiveness and provide metrics to gauge success.

The integrated analytics platform is being used to provide real-time learnings to enhance the customer experience. One example of this is how the Company can use this newly available information to enhance operations during significant storm events. With this new platform, data can be visualized in new ways to uncover insights into experiences customers are having across the Company's phone, web and social media channels. The Company can also use the automated, targeted marketing campaigns to increase effectiveness of communication campaigns during major storm events and for other operational needs.

In February 2019, leveraging insights from the holistic customer profile, the Company began using the new platform to predict the intent of customers when they call. Currently, the Company has a variety of intent predictions configured in the billing, payment, outage and service areas and this and other information has been made more readily available to customer care specialists, who are using it for context into why a customer may be calling and having more informed and productive conversations with customers.

In May 2019, the Program implemented a new capability to better communicate with customers during major storms. The Company is now able to create targeted customer communication lists by leveraging attributes that are particularly relevant during major storms, such as the substation or operations center a customer is served by, or whether the customer or nearby customers are experiencing an outage. These lists will be used to send more specific communications about the specific storm-related circumstances near the customer's home or business. Additionally, in September 2019, these capabilities were expanded to include the ability to automate these email campaigns from the Customer Connect solution and allow them to be configured in advance and quickly executed in desired circumstances.

In mid-2020, the Company introduced a universal bill format to help customers more easily view and understand their bill and energy usage. Positioning this release prior to full deployment not only delivered benefits to customers sooner, but also allowed the Company to more efficiently respond to increased call volume as customers became more familiar with the new bill format.

In April 2021, the Company began deploying the final components of the complete billing and receivables solution for Duke Energy Carolinas, with the final deployment for Duke Energy Kentucky on track to be delivered Spring 2022. In addition to all billing and payment processes, the Company will provide customers with additional self-service capabilities and portals, new rate offering capabilities and advanced billing options. Furthermore, the Company will be able to prioritize the types of information the customer prefers to receive and the methods of communication by which they wish to receive the information, including via web, email and other channels to ensure it is timely, relevant and valuable to them.

Q. PLEASE ELABORATE ON THE NEW BILL FORMAT AND THE BENEFITS FOR CUSTOMERS.

A. As I discussed earlier, the Company introduced a universal bill format as part of the Customer Connect Program that is easier for customers to read and understand. The Company's new bill format removed confusing content, simplified information and made the bill more digestible. Examples of new features include an easy-to-understand usage graph, explanations of commonly used abbreviations and terms (ccf, riders, *etc.*), and easier to read contact information. Additionally, when Customer Connect is fully deployed for Duke Energy Kentucky in Spring 2022, customers will see the average monthly temperature added to the usage graph.

Q. DOES THE NEW BILL FORMAT COMPLY WITH ALL KENTUCKY PSC REGULATIONS?

A. Yes, the design of the new bill format complies with all regulations in 807 KAR 5:006 Section 7(1)(a). An example of the more customer friendly bill format is attached as Attachment RIH-1. This bill format was previously introduced to the Commission as part of the Company's last electric base rate case proceeding in Case No. 2019-00271.

Q. PLEASE EXPLAIN HOW CUSTOMER EXPECTATIONS HAVE OUTPACED DUKE ENERGY KENTUCKY'S PRACTICES.

A. A key objective for Customer Connect is to simplify experiences for customers. To do that, the Company needed to better understand the challenges customers experience when interacting with Duke Energy. The program team researched customer survey data and verbatims and conducted a thorough review of the Company's business processes and associated Commission rules. This research and analysis, combined with industry best practices, expected customer journeys, and capabilities of the new system determined how the Company needed to interact with its customers moving forward. A number of opportunities to improve the customer experience were identified, many of which will be easily implemented when the new system is fully deployed in early 2022 for Duke Energy Kentucky. For example, as discussed earlier, customers want to employ their preferred method of communication when interacting with Duke Energy. Customer Connect will allow customers to choose how and when they want to receive communications. Customers have come to expect communications tailored to their specific desires, such as modern forms of communication, like text messages and email, and this is just one example of how customer expectations have outpaced the Company's processes.

Q. PLEASE DESCRIBE HOW THE COMPANY IS INCORPORATING CUSTOMER NEEDS AND EXPECTATIONS THROUGHOUT THE DESIGN AND IMPLEMENTATION OF CUSTOMER CONNECT.

A. Based on its cumulative experiences with the current CIS, the Company knew the selected platform would need to meet the following core needs: (1) configurability; (2) adaptability; and (3) a customer-centric platform. A simple meter-to-cash replacement would not suffice. After conducting an extensive and rigorous procurement process, the Company is confident the selected suite of programs meets these core needs. The platform has been implemented by more than 760 utilities globally and the Company is taking advantage of the platform's capabilities. By selecting this platform, the Company and its customers will get the benefit of the proven technology as well as the ability to leverage best practices from these other utilities to keep pace with the needs and expectations of customers. Further, because this platform is being used globally by utilities and retailers, it is constantly evolving and being updated to accommodate the latest technologies and user interfaces to help ensure that customers continue to derive benefits from the system.

The Company leveraged industry research to better understand customer expectations and used these insights as input to the functional and technical design. The Company firmly believes this platform provides an opportunity to further shape its future for the benefit of customers.

Industry research confirms that customer expectations are changing; they are more fluid and customers benchmark us against other service companies such as Amazon and FedEx, where there is transparency and awareness in their processes. For example, customers have come to expect the capability to track packages and see, at any given moment, where the package is and when it is expected to be at their home. Duke Energy Kentucky understands its customers have come to expect the same thing from all service providers, including their utility, and is confident the solution selected gives the Company the technology it needs to meet this expectation. To that end, during the "design" phase, the Company took the opportunity to redesign outdated business processes that have been in place for more than 20 years. For example, the Company's current CIS requires customer care specialists to obtain information such as directions to a customer's home and the location of the meter when completing a request to start or stop service. With the deployment of AMI meters, as well as common technologies, like GPS, obtaining this information is no longer necessary. Although this information is no longer needed for service orders, the Company's system and internal process have not evolved to allow for these efficiencies.

The Company has and will continue to survey customers to understand the value they are receiving from the new system. For example, the Company performed consumer testing to gather customer feedback on the design of the Company's new bill format that was implemented as part of the Customer Connect Program. Furthermore, in 2020, the Company undertook an effort to evaluate the newly designed processes and self-service features being delivered as part of the Customer Connect program through a series of both moderated and unmoderated customer experience studies. Ten studies were completed focusing on ensuring experiences and processes are simple, intuitive, engaging, and consistent. The studies included features such as the payment experience, billing and payment program enrollments and collateral, and payment assistance enrollment and management. Leveraging simulated customer experiences through prototypes of the self-service solution and testing environments, participants engaged in task-based studies where behaviors were analyzed to understand what worked successfully in the experience and to identify improvement opportunities. Overall, results were favorable and indicated that customers were overarchingly satisfied and found value in the features and processes explored. Opportunities identified to further enhance the solution were prioritized and evaluated for timing of implementation. Critical areas explored as part of each study included the following:

- Self-service features, navigation, and language
- Transactional communications
- Billing outputs and program management
- Overall process and customer experience

The studies primarily included residential customers. Non-residential customers were engaged in some studies, such as the business start service experience, multi-account business study, as well as landlord and property management customer studies.

Q. THE COMPANY REQUESTED, AND THE COMMISSION APPROVED SEVERAL WAIVERS IN CASE NO. 2019-00271 FOR ITS ELECTRIC SERVICE. DOES THE COMPANY NEED ANY ADDITIONAL WAIVERS AS IT RELATES TO NATURAL GAS?

A. The previously requested and authorized waivers will also apply to the Company's natural gas operations. No additional waivers are being requested at this time.

Q. IS THE COMPANY SEEKING APPROVAL FOR THE REVERT-TO-OWNER PROGRAM IN THIS CASE?

A. Yes, the Company plans to replace its current Automatic Landlord Program with the Revert-to-Owner Program and is seeking approval of the program.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S AUTOMATIC LANDLORD PROGRAM.

A. The Company's Automatic Landlord Program is similar to the new Revert-to-Owner program in that it allows property owners, landlords and/or property management companies (collectively "landlords") to enter into an agreement with the Company that allows residential or non-residential utility service to be automatically transferred into the name of the property owner, landlord or property management company when a tenant requests service to be taken out of their name. This program allows service to automatically revert without interruption of service, and does not require the property owner, landlord or property management company to notify the Company each time service is put in their name, and the automatic transfer does not occur if service in the tenant's name has been disconnected for non-payment.

Enrollment and management of properties in the Automatic Landlord program requires landlords to contact the Company's customer care center to process their requests, which can be a source of frustration for those who may wish to complete their requests outside the Company's normal business hours or without having to spend time on the phone.

Q. HOW IS THE PROPOSED REVERT-TO-OWNER PROGRAM DIFFERENT FROM THE COMPANY'S EXISTING LANDLORD PROGRAM?

A. The Revert-to-Owner program also provides the ability for landlords who own rental properties, including single family, multi-family and/or commercial properties, to avoid a lapse in service by automatically placing electric, natural gas or lighting service in the landlord's name when a tenant voluntarily vacates a property. The Customer Connect program is enhancing this program by adding a new web portal called the "Landlord Experience Portal" where landlords will have self-service access to enroll, view, and manage their properties. The enhancements to this program and the new portal are another way the Company is providing more convenience and control for customers and making it easier for them to business with Duke Energy.

Q. WILL LANDLORDS CURRENTLY ENROLLED IN THE AUTOMATIC LANDLORD PROGRAM HAVE TO RE-ENROLL IN THE NEW REVERT-TO-OWNER PROGRAM?

A. No, customers enrolled in the Automatic Landlord program will automatically be enrolled in the Revert-to-Owner program.

Q. HOW WILL THE NEW LANDLORD EXPERIENCE PORTAL BENEFIT CUSTOMERS?

A. The new Landlord Experience Portal will provide a dashboard view for landlords of all properties registered with the Revert-to-Owner program. Through this digital portal, landlords will also have a view into the status of the utility service at their properties (*e.g.* on in tenant's name, on in landlord's name, off, *etc.*), and will be able to take action to initiate service orders, if needed. They will also have the ability to view and pay their bills, as well as add and remove properties as needed. Customer Care Specialists will continue to be available to assist landlords enrolled in Revert-to-Owner, as needed.

Q. WHAT IS THE IMPLEMENTATION DATE FOR THE CUSTOMER CONNECT SYSTEM?

A. The implementation of the Customer Connect System is ahead of schedule and is currently estimated to be in place for Duke Energy Kentucky in Spring 2022.

III. CONCLUSION

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

A. Yes.

DUKE ENERGY.

duke-energy.com
800.544.6900

Your Energy Bill

Service address
[redacted]

Bill date Aug 2, 2020
For service Jun 30 - Jul 30
31 days

Account number [redacted]

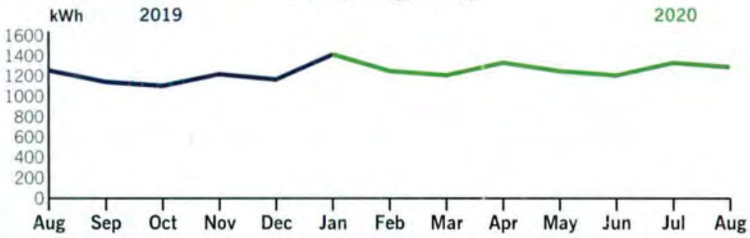
Thank you for your payment.

Billing summary

Previous Amount Due	$258.21
Payment Received Jul 13	$258.21
Current Electric Charges	103.24
Current Gas Charges	118.23
Taxes	5.75
Total Amount Due Aug 27	**$227.22**

Your usage snapshot

Electric usage history



Average temperature in degrees

80° 80° 63° 42° 42° 39° 38° 52° 55° 64° 78° 83° 0°

	Current Month	Jul 2019	12-Month Usage	Avg Monthly Usage
Electric (kWh)	1,287	1,253	16 128	1,241
12-month usage based on most recent history				

Mail your payment at least 7 days before the due date or pay instantly at duke-energy.com/billing. Late payments are subject to a 5.0% late charge.

Please return this portion with your payment. Thank you for your business.

10000027742

DUKE ENERGY.

Duke Energy Return Mail
PO Box 1090
Charlotte, NC 28201-1090

Account number
[redacted]

Amount due

$227.22 *by Aug 27*	*After Aug 27, the amount due will increase to $238.58.*

$____________ Add here, to help others with a contribution to WinterCare

$____________ **Amount enclosed**

[redacted]

Duke Energy Payment Processing
PO BOX 1326
CHARLOTTE, NC 28201-1326

88[redacted]00033000030582100006650000000970821 0

DUKE ENERGY. duke-energy.com 800.544.6900

Account number [redacted]

We're here for you

Report an emergency

Electric/Gas outage		duke-energy.com/outages
	Electric	800.543.5599
	Gas	800.634.4300

Convenient ways to pay your bill

Online	duke-energy.com/billing
Automatically from your bank account	duke-energy.com/autodraft
Speedpay (fee applies)	duke-energy.com/pay-now 800.544.6900
By mail payable to Duke Energy	P.O. Box 1326 Charlotte, NC 28201-1326
In person	duke-energy.com/location

Help managing your account

Register for free paperless billing	duke-energy.com/paperless
Update your account information	duke-energy.com/my-account
Mobile website	duke-energy.com/my-account

Correspond with Duke Energy

P.O. Box 1326
Charlotte, NC 28201

Contact Duke Energy

Online	duke-energy.com
Call (7 a.m. to 7 p.m.)	800.544.6900
For hearing impaired TDD/TTY	800.648.6056 or 711

Request the condensed or detailed bill format

Call (7a.m. to 7 p.m.)	800.544.6900

Important to know

Your next meter reading: Aug 28
Please be sure we can safely access your meter for actual readings. Don't worry if your digital meter flashes eights from time to time. That's a normal part of the energy measuring process.

Your electric service may be disconnected if your payment is past due
If payment for your electric service is past due, we may begin disconnection procedures. If your service is disconnected because of a missed payment, you must pay your past-due balance in full, plus a reconnection fee, before your service will be reconnected. The reconnection fee is $3.45 for electric service that may be reconnected remotely, $75 for electric service that is not eligible to be reconnected remotely, and $25 for gas service. In such situations where both electric and gas service are disconnected for non-payment, the reconnection fee will not exceed $88 for both. A security deposit may also be required.

Electric service does not depend on payment for other products or services
Non-payment for non-regulated products or services (such as surge protection or equipment service contracts) may result in removal from the program but will not result in disconnection of electric service.

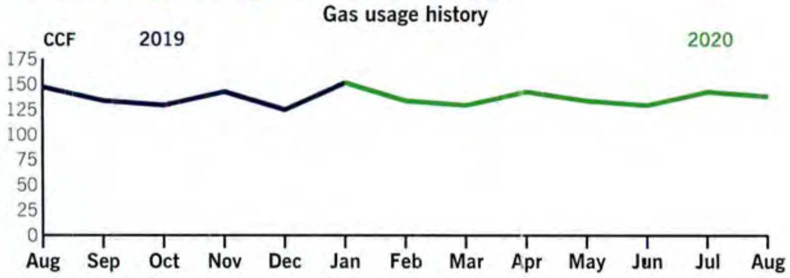
When you pay by check
We may process the payment as a regular check or convert it into a one-time electronic check payment.

Para nuestros clientes que hablan Español
Representantes bilingües están disponibles para asistirle de lunes a viernes de 7 a.m. - 7 p.m. Para obtener más información o reportar problemas con su servicio eléctrico, favor de llamar al 800.544.6900.

DUKE ENERGY.
duke-energy.com
800.544.6900

Account number [redacted]

Your usage snapshot - continued



Average temperature in degrees

2019 80° 80° 63° 42° 42° 39° 38° 52° 55° 64° 78° 83°

	Current Month	Jul 2019	12-Month Usage	Avg Monthly Usage
Gas (CCF)	138	147	1,779	137
12-month usage based on most recent history				

Current electric usage for meter number [redacted]	
Actual reading on Jul 30	17178
Previous reading on Jun 30	- 15891
Energy used	1287 KWH

A kilowatt-hour (kWh) is a measure of the energy used by a 1,000-watt appliance in one hour. A 10-watt LED lightbulb would take 100 hours to use 1 kWh.

Current gas usage for meter number [redacted]	
Actual reading on Jul 30	1958
Previous reading on Jun 30	- 1820
Gas used	138 CCF

One centum cubic foot (CCF) is the amount of gas in a 100-cubic-foot space. If you have a standard oven, it would take about 20 hours to use 1 CCF of gas.

Billing details - Electric

Your current rate is Residential Service.

Duke Energy Delivery	
Service Delivery	
Customer Charge	$12.60
Energy Chrg	
1,287.00 KWH @ 0.07796000	100.33
Elec DSM Rider	
1,287.00 KWH @ -0.00314300	-4.05
Home Energy Assistance Prgm	0.30
Rider PSM	
1,287.00 KWH @ 0.00007000	0.09
Elec Fuel Adjustment	
1,287.00 KWH @ -0.00468400	-6.03
Total Current Charge	**$103.24**

DUKE ENERGY. duke-energy.com 800.544.6900

Account number [redacted]

Billing details - Gas

Customer Charge	$16.50
Gas Delivery Charge	
138.21 CCF @ 0.46920000	64.85
Gas DSM Rider	
138.21 CCF @ 0.03073500	4.25
Gas Cost Recovery	
138.21 CCF @ 0.23540000	32.53
Home Energy Assistance Prog	0.10
Total Current Charge	**$118.23**

Your current rate is Residential Service.

Billing details - Taxes

Rate Incr for School Tax	$5.75
Total Taxes	**$5.75**

DUKE ENERGY.
duke-energy.com
800.544.6900

Your Energy Bill

Service address
[redacted]

Bill date Aug 2, 2020
For service Jun 30 - Jul 30
31 days

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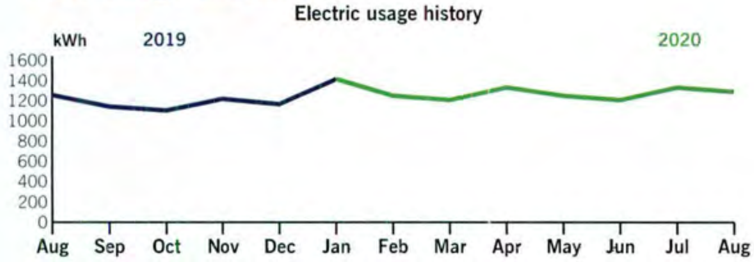

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[redacted]

Duke Energy Payment Processing
PO BOX 1326
CHARLOTTE, NC 28201-1326

889[redacted]0003300003058210000665000000009708210

DUKE ENERGY. duke-energy.com 800.544.6900

Account number [redacted]

We're here for you

Report an emergency		
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	Gas	800.634.4300

Convenient ways to pay your bill

Online	duke-energy.com/billing
Automatically from your bank account	duke-energy.com/autodraft
Speedpay (fee applies)	duke-energy.com/pay-now 800.544.6900
By mail payable to Duke Energy	P.O. Box 1326 Charlotte, NC 28201-1326
In person	duke-energy.com/location

Help managing your account

Register for free paperless billing	duke-energy.com/paperless
Update your account information	duke-energy.com/my-account
Mobile website	duke-energy.com/my-account

Correspond with Duke Energy

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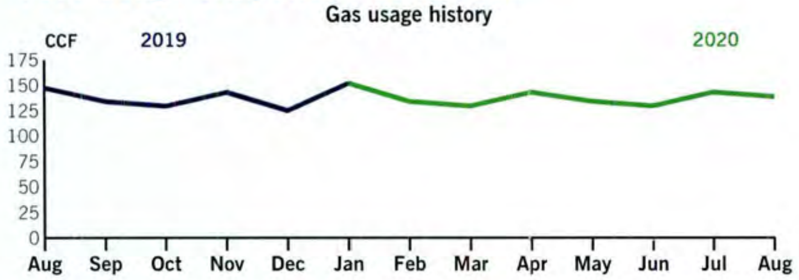

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Natural Gas Rates; 2) Approval of New Tariffs; and 3) All Other Required Approvals and Relief.	)))))	Case No. 2021-00190

DIRECT TESTIMONY OF

JEFF L. KERN

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

June 1, 2021

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeff L. Kern. 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 Rates and Regulatory Strategy Manager. 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's Degree in Quantitative Analysis from the University of Cincinnati. I began my career with the Cincinnati Gas & Electric Company (CG&E) as a rate analyst in 1988. I was employed by New York State Electric & Gas Company between 1993 and 1997, returning to CG&E in 1997 as a Senior Rate Analyst. In 1998, I became an administrator in Gas Operations. Since that time, I have held positions of increasing responsibility in Gas Operations, having responsibility for assuring adequate supply of gas for the retail customers of Duke Energy Kentucky and Duke Energy Ohio, Inc. In 2018, I left the gas operations business unit and joined Pricing and Regulatory Solutions as Lead Rates and Regulatory Strategy Analyst. I was promoted to Rates and Regulatory Strategy Manager in 2020.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS RATES AND REGULATORY STRATEGY MANAGER.

A. I am responsible for performing analyses and studies to support new or revised rates, providing oral and written testimony before regulatory agencies and other regulatory support, meeting with commission staff members in support of filings, rate changes, or tariff administration issues, assisting in administration of rates and programs, preparing or coordinating preparation of required regulatory compliance filings, and leading projects related to new or revised rates.

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

A. Yes. I provided testimony in Case No. 2019-00271, Duke Energy Kentucky's electric base rate case proceeding.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY OTHER REGULATORY AGENCIES?

A. I have testified before the Public Utilities Commission of Ohio and have submitted written testimony before the Federal Energy Regulatory Commission.

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

A. I am responsible for Duke Energy Kentucky's proposed natural gas rate design. 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 natural gas rate schedules, riders, and natural gas Service Regulations, and quantify the effect of these changes to our retail natural gas 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.

Q. PLEASE DESCRIBE SCHEDULE L-1.

A. Schedule L-1 shows the rate schedules that Duke Energy Kentucky proposes to implement.

Q. PLEASE DESCRIBE SCHEDULE L-2.1.

A. Schedule L-2.1 contains Duke Energy Kentucky's current rate schedules indicating through underlining and coding where changes occur in the proposed rate schedules. Note that the following schedule sheet numbers only receive an update to the Company's address and/or the schedule's filing and effective date. There are no substantive changes to these tariff schedules which include sheet numbers 1, 11, 20, 21, 22, 23, 24, 27, 28, 29, 55, 59, 60, 61, 62,70, 77, 80 and 83.

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.

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; Schedule M shows that Duke Energy Kentucky is proposing a 12.7 percent increase in the Residential service class, a 14.8 percent increase in the General Service class, a 15.8 percent increase in the Firm Transportation-Large service class, and a 14.9 percent increase in the Interruptible Transportation service class. These average increases are based upon base rates which include the gas cost adjustment clause and other riders. There is also a Schedule M provided for base period revenues at current and proposed rates.

Q. PLEASE DESCRIBE SCHEDULE M-2.1.

A. Schedule M-2.1 shows test period base revenue dollars at current rates 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 cubic feet of gas (Mcf) for each rate class. There is also a Schedule M-2.1 provided for base period base revenue dollars.

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 is normalized sales for the twelve months ended December 31, 2022. Schedule M-2.2, pages 2 through 22, 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, GS, IT, and FT-L. 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 13.3 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 July 1, 2021 and the dates the proposed rates are expected to be filed are June 1, 2021.

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 JLK-1, these various statements are included.

III. RETAIL NATURAL GAS RATE SCHEDULES AND RIDERS

A. RATE DESIGN AND MAJOR RETAIL NATURAL GAS 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 40 percent.

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. In particular, the Company proposes increased customer charges for rate schedules RS and GS to better align the charges with cost causation.

Q. WHAT ARE THE COMPANY'S MAJOR RETAIL NATURAL GAS RATE SCHEDULES?

A. The Company's major retail natural gas rate schedules include: Rate RS -

Residential Service (Rate RS); Rate GS –General Service (Rate GS); Rate IT – Interruptible Service (Rate IT); and Rate FT-L - Firm Transportation Service (Rate FT-L). Together, these rate schedules comprise a substantial portion of the Company's retail natural gas revenue requirement.

Q. PLEASE DESCRIBE THE COMPANY'S RATE DESIGN OBJECTIVES FOR RATES RS, GS, IT, AND FT-L.

A. Given the overall percentage increase in this case, our rate design objective for these rate schedules is to generally increase the rates to maintain a similar structure that minimizes impacts to the class of customers while collecting the total revenue requirement. Aside from this, there are no significant structural changes to the rate schedules. In addition, as more fully described below, the Company has a Weather Normalization Adjustment (WNA) Rider applicable to Rates RS and GS. This rider normalizes the volumetric component of base revenues for Rates RS and GS customers' bills, adjusting the bills to mitigate the volatility in natural gas consumptions due to abnormal weather during winter months.

Q. WHAT ARE THE PROPOSED CUSTOMER CHARGES?

A. The proposed customer charge for each rate is as follows: for Rate RS, $19.00; for Rate GS, $58.00; for Rate IT, $430.00; and for Rate FT-L, $430.00. Attachment JLK-2 sets forth the customer-related costs of providing service to the various customer classes. This information was obtained from the functional cost of service study provided by Mr. Ziolkowski. These customer charges better align the recovery of customer related costs with the fixed nature of these costs resulting in a better price signal to customers.

Q. DO THE PROPOSED CUSTOMER CHARGES ALIGN WITH THE RATE DESIGN PRINCIPLE OF GRADUALISM?

A. Yes. As shown in attachment JLK-2, the cost of service study supports a residential customer charge value of $31.44. However, the Company proposes a residential customer charge of $19.00. Similarly, the Rate GS customer charge is proposed to modestly increase from the current value of $50.00 to $58.00, while the cost of service study supports a customer charge of $60.48.

Q. WHAT ARE THE ADMINISTRATIVE CHARGES PROPOSED FOR RATES FT-L AND IT?

A. Customers may receive service through a combination of Rates FT-L and IT and in this situation only receive one administrative charge on their bill. Therefore, the Company proposes the current administrative charge for both rates remain at $430.00, which is between the charges supported by the cost of service study of $323.99 for FT-L and $588.20 for IT.

Q. HAVE YOU PREPARED RATE SCHEDULES FOR THE COMPANY'S NATURAL GAS RATES?

A. Yes. Again, there are no significant structural changes. The design objective of the natural gas rates was to collect the revenue requirement while maintaining the existing structural characteristics of the rate schedules. More information is provided on Schedule L.

B. WEATHER NORMALIZATION ADJUSTMENT RIDER (RIDER WNA)

Q. PLEASE DESCRIBE RIDER WNA?

A. In this case, the Company proposes a normalized level of revenues and expenses for a test period, which is designed to be the most reasonable estimate of the Company's operations during the time the rates are to be in effect. These normalized revenues and expenses include the assumption of normal weather conditions to eliminate unusual weather related fluctuations in the test period that may otherwise cause rates to be set too high or too low. Specifically, test period weather related sales volumes reflect normal levels of heating degree days. (A heating degree day value is calculated by taking the difference between average daily temperature and a base temperature value). As described in Company witness Dr. Benjamin Walter Bohdan Passty's testimony, the average daily temperatures represent normal weather and are determined based on 30 years of past weather data. However, normal weather rarely occurs which can cause customers' bills to fluctuate significantly from month to month and can result in the Company earning more or less than the authorized rate of return. In an effort to help reduce these fluctuations in customer bills and Company earnings, the Company's WNA mechanism adjusts the volumetric component of base delivery charges on customer bills to reflect normal weather conditions. Although customers use gas all year round, the largest share of the Company's revenue is dependent on heating load. Heating load generally occurs during the months of November through April (*i.e.*, winter months) and, because it is highly correlated with temperature, can vary significantly when the temperature deviates from "normal." Under the WNA mechanism, when temperatures are colder than normal, volumetric sales will be higher than normal and the customer will receive a credit on their bill. When weather is warmer than normal, volumetric sales will be lower than normal; so, the customer's bill includes a surcharge. The result is that customers' bills during winter months should not fluctuate as significantly as they would without a WNA mechanism, and the Company should receive more stable base revenues.

Q. HOW IS THIS ADJUSTMENT PERFORMED?

A. The equation for the WNA mechanism can be found on Rider WNA, Sheet No. 65 in Schedule L-1. As detailed, the adjustment is based on the difference between actual and normal degree days associated with a customer's billing period. This heating degree day deviation is combined with two class level parameters to calculate a delivery charge rate adjustment that is applied to the customer's consumption for the billing period. The two class level parameters are called the Base Load (BL) and the Heat Sensitivity Factor (HSF).

Q. WHAT VALUES ARE PROPOSED FOR THE BL AND HSF?

A. As discussed in Dr. Passty's testimony, the proposed values for BL and HSF are 1.047887 Mcf and 0.015467 Mcf/DD, respectively, for Rate RS. For Rate GS, they are 9.159645 Mcf and 0.096462 Mcf/DD, respectively. As ordered by the Commission in Case 2018-00261, these proposed values will be updated whenever the Company files a base rate case. Since these factors will only change through a base rate case, they are now included on Tariff Sheet No. 65.

Q. DID THE COMPANY PREPARE A REPORT ON RIDER WNA SEASONAL RESULTS AS ORDERED BY THE COMMISSION?

A. Yes. The report is provided as Attachment JLK-3 and shows that customers received a surcharge when weather was warmer than normal and a credit when weather was colder than normal as expected.

Q. WERE THE WEATHER NORMALIZATION ADJUSTMENTS CONSISTENT WITH HEATING DEGREE DAY DATA?

A. Yes. For the winter of 2019-2020, actual heating degree days (base 59) totaled 2,991. Normal heating degree days are 3,372. This winter was much warmer than normal and a WNA surcharge was experienced. For the winter of 2020-2021, April 2021 data was not available at the time this testimony was being prepared so data is for November 2020 through March 2021. For this period, normal degree days are 3,091 and actual degree days totaled 2,995. Weather was again warmer than normal, but not as warm as the previous winter so the surcharge was significantly smaller. During both of these winters there were individual months that were colder than normal, specifically November and December 2019 and February 2021. In each of these months, the WNA resulted in a credit to customers.

Q. WERE CUSTOMER INQUIRIES AND COMPLAINTS REGARDING THE WEATHER NORMALIZATION ADJUSTMENT TRACKED DURING THE TWO WINTER SEASONS?

A. Yes. During the winter of 2019-20, there were 4 inquiries and 2 complaints, while during the winter of 2020-21 through March, there were no inquiries or complaints. Since there has been such minimal reaction from customers, the Company proposes to discontinue separately tracking inquiries and complaints regarding the WNA.

C. NEW RIDERS

Q. DOES THE COMPANY PROPOSE ANY NEW RIDERS IN THIS CASE?

A. Yes. The Company proposes to implement a Governmental Mandate Adjustment mechanism (Rider GMA) which will enable the Company to implement and respond to governmental directives/mandates impacting the utility, including changes in federal or state tax rates and regulations promulgated by the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA). This is more fully described in the testimony of Company witnesses Sarah E. Lawler, John R. Panizza, and Brian R. Weisker. The rider would initially be set at $0.0000 and would require the Company file a separate application to implement any adjustments to the Rider GMA in response to a governmental mandate, which will be subject to Commission determination of reasonableness.

D. REVISED RIDERS AND MISCELLANEOUS CHARGES

Q. DOES THE COMPANY PROPOSE TO ELIMINATE ANY TARIFF SCHEDULES IN THIS CASE?

A. No.

Q. WHAT CHANGES ARE PROPOSED TO THE COMPANY'S CHARGES FOR RECONNECTION OF SERVICE?

A. Duke Energy Kentucky proposes revision to the charges for reconnection of natural gas service as discussed below:

(1) The reconnection charge for service which has been disconnected due to enforcement of Rule 3, Sheet No. 25, Billing and Payment shall be $90.00.

(2) The reconnection charge for service which has been disconnected within the preceding twelve months at the request of the customer shall be $90.00.

(3) The reconnection charge for service which has been disconnected because of fraudulent use shall be $90.00.

Q. WHAT INFORMATION IS USED TO SUPPORT THE SERVICE RECONNECTION COSTS?

A. Attachment JLK-4 shows the calculation of natural gas service reconnection and the Company's proposed value.

Q. DESCRIBE THE INFORMATION PRESENTED IN ATTACHMENT JLK-4, CALCULATION OF RECONNECTION FEES.

A. The reconnection fee calculations use a fully loaded labor rate for craft labor and estimated labor hours to complete reconnection service. The estimated completion times are based on management expertise and have not changed since the previous calculation in Case No. 2018-00261.

Q. IS THE COMPANY PROPOSING ADDITIONAL CHANGES TO MISCELLANEOUS CHARGES?

A. Yes. The Company proposes to make changes to the Meter Pulse Service rate, Rate MPS.

Q. WHAT CHANGES ARE MADE TO RATE MPS?

A. The Company proposes to increase the Meter Pulse Equipment and the Meter Index costs to $1,000 and $700, respectively, due to the increased cost to provide this equipment as supported in Attachment JLK-5. This optional service is intended for large commercial and industrial customers who desire more detailed information about their natural gas usage. Currently, there are only 13 customers taking advantage of this voluntary service.

IV. OTHER TARIFF CHANGES

Q. WHAT CHANGES ARE PROPOSED FOR THE FULL REQUIREMENTS AGGREGATION SERVICE RATE, RATE FRAS?

A. Text is added to Rate FRAS to specify the nomination deadline for scheduling natural gas deliveries. The deadline is referenced to the North American Energy Standards Board (NAESB) timely nomination cycle rather than a specific time to avoid the need for tariff changes if NAESB implements changes to the nomination cycles in the future.

Q. WHAT CHANGES ARE PROPOSED FOR THE INTERRUPTIBLE MONTHLY BALANCING SERVICE, RATE IMBS?

A. The Company proposes changing the imbalance charge to $0.1366 per MCF to reflect current charges from the interstate pipeline providing the storage service that is used to balance the system. Calculations to support the imbalance charge are provided in Attachment JLK-6.

Q. ARE THERE ADDITIONAL CHANGES PROPOSED FOR THE INTERRUPTIBLE MONTHLY BALANCING SERVICE, RATE IMBS?

A. Yes. There are two proposed revisions to the text of Rate IMBS. First, text regarding the daily trade deadline of two business days is deleted to remain consistent with changes to Rate GTS, Gas Trading Service, described below. Text was also added to incorporate a nomination deadline for IT suppliers consistent with the addition to Rate FRAS, Full Requirement Aggregation Service as discussed above.

Q. WHAT CHANGES ARE PROPOSED FOR THE GAS TRADING SERVICE, RATE GTS?

A. The Company has developed a new system for managing gas supply for transportation customers as well as third party suppliers called Gas Transaction Information System (GTIS). While this new system allows for trades between suppliers, it does not specifically allow for the posting of offers for purchase, sale or trade, but instead permits suppliers to elect to have their imbalance positions displayed. Therefore, obsolete language in Rate GTS has been deleted. The language regarding the daily trade deadline of two business days was also deleted to provide more flexibility to suppliers with no impact on the Company since the trades are only inter-pool transfers and do not change the volumes of gas delivered into the system.

Q. PLEASE EXPLAIN THE CHANGE TO THE COMPANY'S FRANCHISE FEE TARIFF.

A. The change is textual in nature to enhance clarity. The tariff currently contemplates inclusion of any fee that a local government may impose on the company, not just a franchise fee. The change is to clarify the title to apply to any local government fee, and removes the language referring to fees based upon gross receipts as it relates to franchises. The Company currently has several different fee arrangements charged by municipalities beyond just those based upon gross receipts. There are flat fees, pure gross receipts fees, and gross receipt fees that include caps at a particular dollar amount. The textual change is intended to ensure there is flexibility for local governments in how they structure the fees they impose.

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 July 1, 2021, for all customers.

Q. WERE SCHEDULES L, L-1, L-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) AND FR 16(8)(n), FR 17(4) AND ATTACHMENTS JLK-1, JLK-2, JLK-3, JLK-4, JLK-5, AND JLK-6 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. IS THE INFORMATION CONTAINED IN THOSE SCHEDULES AND SUPPLEMENTAL 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 June 1, 2021, Duke Energy Kentucky will be seeking approval by the Public Service Commission, Frankfort, Kentucky, of an adjustment of natural gas rates and charges proposed to become effective on and after July 1, 2021. The Commission has docketed this proceeding as Case No. 2021-00190.

The proposed gas rates are applicable to the Company's service area including following communities:

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

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

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

Current Budget Billing Plan Description:

Annual Plan:

- The Annual Plan provides 11 months of equal payments by using 12 months of customer's usage, dividing the usage by 11, and using the result to calculate the bill.
  Month 12 is a settle-up month between the billed amounts and customer bills based on actual usage
- A bill message is sent after 6 months with a suggested new bill amount if the budget bill amounts compared to the actual bill amounts exceeds a Company set threshold; however, Customer must contact Company to change the amount.
- The budget bill amount is changed as needed after the 12 month review.

Proposed Budget Billing Plan Description:

Annual Plan:

- The Annual Plan provides 12 months of equal payments by using 12 months of customer's usage, dividing the usage by 12, and using the result to calculate the bill.
  Month 12 is a settle-up month between the billed amounts and customer bills based on actual usage
- A bill message is sent after 3, 6, and 9 months with new bill amount if the budget bill amounts compared to the actual bill amounts exceeds a Company set threshold.
- The budget bill amount is also changed as needed after the 12 month review.

Current Landlord Programs
This is a new section.

Proposed Landlord Programs
The Company will provide a Revert-to-Owner program available to Landlords, property managers, or other property owners to provide continuity in service when a tenant notifies the Company to discontinue service by automatically switching the account to the Landlord until a new tenant sets up service or the Landlord requests to discontinue service. The program is not applicable in situations where a tenant has been disconnected for nonpayment or the Company has been notified of a safety issue that warrants the termination of service. The provisions of the Automatic Landlord Transfer Agreement are outlined below.

Eligibility and Enrollment

1. An email address is required for enrollment. The Revert-to-Owner agreement may be emailed to the landlord, or accepted digitally through an online portal, known as the "Landlord Experience."
2. Landlord may enroll properties via self-service using the Company's "Landlord Experience" online portal or provide in writing a list of properties they wish to enroll in the program on a contract provided by the Company.
3. Eligibility to enroll in the Revert-to-Owner program requires any delinquent balance associated to the Landlord to be paid.
4. The Landlord may add and remove properties from the program at any time either by self-service using the "Landlord Experience" online portal or by contacting the Company's customer service department, and will be responsible for all charges associated to the properties enrolled while service is/was in their name.
5. Landlords may remove properties from the Revert-to-Owner program using the "Landlord Experience" online portal or by contacting the Company's customer service department.
6. The Landlord is responsible for notifying the Company of any changes in mailing address.
7. The Company shall maintain the discretion to remove a Landlord from the program for failure to pay.

Section VII – Deposits
(Gas Tariff Sheet No. 26)

Current Deposits:
A satisfactory payment record is defined as twelve (12) months of service without being disconnected for nonpayment and without the occurrence of fraud, theft, or bankruptcy.

Proposed Deposits:
A satisfactory payment record is defined as having had twelve (12) months of service with no more than three final notices and no disconnections for nonpayment.

Residential Service – Rate RS
(Gas Tariff Sheet No. 30)

	Current Rate	Proposed Rate
Customer Charge per month	\$16.50	\$19.00
Base Rate for all Ccf	\$0.46920	\$0.57926
GCA for all Ccf	\$0.35510	\$0.35510
Total Rate (Base Rate + GCA) for all Ccf	\$0.82430	\$0.93436

General Service – Rate GS
(Gas Tariff Sheet No. 31)

	Current Rate	Proposed Rate
Customer Charge per month	$50.00	$58.00
Base Rate for all Ccf	$0.29243	$0.39405
GCA for all Ccf	$0.35510	$0.35510
Total Rate (Base Rate + GCA) for all Ccf	$0.64753	$0.74915

Full Requirements Aggregation Service – Rate FRAS
(Gas Tariff Sheet No. 44)

Current Balancing Requirements:
Suppliers must deliver to the Company daily quantifies of gas in accordance with the provisions of Rate IMBS.

Proposed Scheduling and Balancing Requirements:
Suppliers must deliver to the Company daily quantifies of gas in accordance with the provisions of Rate IMBS.

No later than one hour prior to the North American Energy Standards Board (NAESB) deadline for the timely nomination cycle, Supplier shall submit a valid nomination through the Company's EBB of its total city gate quantities of gas scheduled for the following gas day. The Company will have no obligation to accommodate post-timely nominations, or changes thereto, that are made after the daily deadline.

Interruptible Transportation Service – Rate IT
(Gas Tariff Sheet No. 50)

	Current Rate	Proposed Rate
Customer Charge per month	$430.00	$430.00
Base Rate for all Ccf	$0.09982	$0.11573

Firm Transportation Service Rate FT-L
(Gas Tariff Sheet No. 51)

	Current Rate	Proposed Rate
Customer Charge per month	$430.00	$430.00
Base Rate for all Ccf	$0.18210	$0.21339

Aggregation Service for Interruptible Gas Transportation – Rate AS
(Gas Tariff Sheet No. 55)

Current Rate:
Pooling service available to (1) customers receiving interruptible gas transportation service under Rate IT and special contract interruptible customers who are acting as their own pool operator for supply management purposes, and (2) pool operators designated by Rate IT and special contract interruptible customers to manage gas supplies on their behalf and as a part of an aggregated customer pool. For purposes of administering this tariff, the usages of all customers within a pool will be combined into a single pool usage number, which will be matched against the pool operator's total deliveries to its Rate IT and special contract interruptible transportation pool.

Proposed Rate:
There are no proposed rate changes to this rate.

Gas Trading Service – Rate GTS
(Gas Tariff Sheet No. 57)

	Current Rate	Proposed Rate
Per Transaction	$5.00	No proposed changes

Current Character of Service:
The Company will operate an electronic bulletin board (EBB) through which eligible pool operators can notice offers of gas supplies for purchase, sale, or trade.

Daily imbalance trades or transfers must be completed within two (2) business days from the date that the trade or transfer applies. Monthly imbalance trades or transfers must be completed within two (2) business days following the end of the month.

Transactions will be completed when the pool operator(s) on both sides of a transaction key their acceptance into the EBB. When that occurs, all other would-be acceptors of the offer are locked out. The Company will adjust the daily/monthly accounts of both parties to a transaction in order to record the volume transfer embodied in the transaction. Any dollar payments, receipts, or exchanges of other consideration agreed upon between the parties to a transaction are outside the scope of this tariff and must be completed between the parties themselves.

Proposed Character of Service:
The Company will operate an electronic bulletin board (EBB) through which eligible pool operators can perform daily/monthly imbalance trades or transfers. All trades or transfers must be completed within two (2) business days following the end of the month.

Transactions will be completed when the pool operator(s) on both sides of a transaction key their acceptance into the EBB. The Company will adjust the daily/monthly accounts of both parties to a transaction in order to record the volume transfer embodied in the transaction. Any dollar payments, receipts, or exchanges of other consideration agreed upon between the parties to a transaction are outside the scope of this tariff and must be completed between the parties themselves.

Interruptible Monthly Balancing Service Rate IMBS
(Gas Tariff Sheet No. 58)

	Current Rate	Proposed Rate
All Pools per Mcf	$0.1097	$0.1366

Current Character of Service
For purposes of administering this tariff, the daily and monthly usage of all customers within an individual pool will be combined into single daily/monthly pool usage number, which will be matched against the pool operator's total daily/monthly deliveries to its individual transportation pool.

Proposed Character of Service
For purposes of administering this tariff, the daily and monthly usage of all customers within an individual pool will be combined into single daily/monthly pool usage number, which will be matched against the pool operator's total daily/monthly deliveries to its individual transportation pool. No later than one hour prior to the NAESB deadline for the timely nomination cycle, pool operator shall submit a valid nomination through the Company's EBB of its total city gate quantities of gas scheduled for the following gas day. The Company will have no obligation to accommodate post-timely nominations, or changes thereto, that are made after the daily deadline.

Current Service Description:
Daily imbalance trades/transfers made through the Company's EBB must be completed within two (2) business days from the date that the trade or transfer applies. Monthly imbalance trades to comply with the

monthly balancing requirements of Rate IMBS must be completed within two (2) business days following the end of the month.

Proposed Service Description:
All daily and monthly imbalance trades or transfers must be completed within two (2) business days following the end of the month.

Distributed Generation Service – Rate DGS
(Gas Tariff Sheet No. 59)

	Current Rate	Proposed Rate
Administration Charge	$25.00	No Proposed Rate Changes to this Rider
Minimum Capacity Reservation Charge	$2.00	
Facilities Charge	Per Service Agreement	
Delivery Charge	Per Applicable Service Tariff	

Main Extension Policy – Rider X
(Gas Tariff Sheet No. 60)

Current Rate:
Normal Extensions. An extension of one hundred (100) feet or less shall be made by the Company to an existing distribution main without charge for a prospective customer who shall apply for and contract to use service for one year or more.

Proposed Rate:
There are no proposed rate changes to this rider.

Demand Side Management Cost Recovery Rider – Rider DSM
(Gas Tariff Sheet No. 61)

	Current Rate	Proposed Rate
DSM Charge	PC + LR + PI + BA	No Proposed Rate Changes to this Rider

PC = DSM Program Cost Recover
LR = Lost Revenue from Decreased Throughput Recovery
PI = DSM Program Incentive Recovery
BA = DSM Balance Adjustment

Demand Side Management Rate – Rider DSMR
(Gas Tariff Sheet No. 62)

	Current Rate	Proposed Rate
DSMR per Ccf	$0.045817	No Proposed Rate Changes to this Rider
Home Energy Assistance Program per bill	$0.30	

Weather Normalization Adjustment Rider – Rider WNA
(Gas Tariff Sheet No. 65)

	Current Factors	Proposed Factors
Base Load for RS	1.106333	1.047887
Heat Sensitivity Factor for RS	0.015283	0.015467
Base Load for GS	9.745755	9.159645
Heat Sensitivity Factor for GS	0.090515	0.096462

Governmental Mandate Adjustment – Rider GMA
(Gas Tariff Sheet No. 66)

Current Rate:
This is a new tariff schedule.

Proposed Rate:
Customers shall be assessed a surcharge or credit to enable the Company to fully recover all costs associated with governmental mandates including, but not limited to: 1) changes in the state or federal corporate tax rate; and 2) for compliance with regulations promulgated by the U.S. Department of Transportation Pipeline and Hazardous Materials Administration, as approved by the Kentucky Public Service Commission. The monthly billing amount calculated for each rate schedule for which this rider is eligible shall increase or decrease by the billed usage multiplied by the applicable rate below.

GMA Surcharge or Credit per Ccf

Residential (Rate RS)	$0.00 / Month
General Service (Rate GS)	$0.00 / Month
Firm Transportation – Large (Rate FT-L)	$0.0000 / Ccf
Interruptible Transportation (Rate IT)	$0.0000 / Ccf

Gas Cost Adjustment Clause – Rider GCA
(Gas Tariff Sheet No. 70)

	Current Rate	Proposed Rate
GCA Rate	EGC + RA + AA + BA	No Proposed Rate Changes to this Rider

EGC = Expected Gas Cost
RA = Refund Adjustment
AA = Actual Adjustment
BA = Balance Adjustment

Gas Cost Adjustment Transition Rider – Rider GCAT
(Gas Tariff Sheet No. 77)

	Current Rate	Proposed Rate
Charge (Credit) per ccf	($0.0280)	No Proposed Rate Changes to this Rider

Bad Check Charge
(Gas Tariff Sheet No. 80)

	Current Rate	Proposed Rate
Bad Check Fee	$11.00	No Proposed Rate Changes to this Rider

Charge for Reconnection of Service
(Gas Tariff Sheet No. 81)

	Current Rate	Proposed Rate
Reconnect charge for service which has been disconnected due to enforcement of Rule 3	$75.00	$90.00
Reconnect charge for service which has been disconnected within the preceding twelve months at the request of the customer	$75.00	$90.00
If service is discontinued because of fraudulent use	$75.00 plus estimated gas used and expenses incurred by the Company	$90.00 plus estimated gas used and expenses incurred by the Company

Local Franchise Fee
(Gas Tariff Sheet No. 82)

Current Rate:
Local Franchise Fee
There shall be added to the customer's bill, listed as a separate item, an amount equal to the fee now or hereafter imposed by local legislative authorities, whether by ordinance, franchise or other means, which fee is based on the gross receipts collected by the Company from the sale of gas to customers within the boundaries of the particular legislative authority. Such amount shall be added exclusively to bills of customers receiving service within the territorial limits of the authority imposing the fee.

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

Curtailment Plan for Management of Available Gas Supplies
(Gas Tariff Sheet No. 83)

Current Rate:
In the event of an emergency which necessitates curtailment of gas service, Duke Energy Kentucky, Inc. shall curtail gas service to its customers in the manner set forth herein, except where the Public Service Commission of Kentucky (Commission) or other authority having jurisdiction in the matter orders otherwise.

Proposed Rate:
There are no proposed rate changes to this rider.

Meter Pulse Service – Rate MPS
(Gas Tariff Sheet No. 84)

	Current Rate	Proposed Rate
Installation of Meter Pulse Equipment	\$860.00	\$1,000.00
If replacement of Meter Index is necessary, additional charge of:	\$635.00	\$700.00
If the Company is required to make additional visits to the meter site due to the inability to gain access to the meter location or the necessary Communication Link has not been installed, or the Communication Link is not working properly, the Company may charge the customer for any additional trip to the meter site at the per visit rate of:	\$60.00	No Change

IMPACT OF PROPOSED RATES

The foregoing rates reflect a proposed increase in gas revenues of approximately $15,228,161 or 13.39% over current total gas revenues to Duke Energy Kentucky. The estimated amount of increase per customer class is as follows:

	Total Increase ($)	Total Increase (%)
Rate RS – Residential Service:	$9,958,419	12.66%
Rate GS – Commercial Service	$3,532,186	14.78%
Rate GS – Industrial Service	$359,887	14.63%
Rate GS – Other Public Authority Service	$314,235	14.63%
Rate FT-L – Firm Transportation Service	$856,152	15.73%
Rate IT – Interruptible Transportation Service	$266,047	14.92%
Charge for Reconnection of Service	$4,673	20.0%
Interdepartmental	$4,129	14.87%
Special Contracts	-$67,567	-26.17%

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

	Average ccf/Bill	Monthly Increase ($)	Percent Increase (%)
Rate RS – Residential Service:	57	8.77	12.7%
Rate GS – Commercial Service	363	44.89	14.8%
Rate GS – Industrial Service	1,151	124.96	14.6%
Rate GS – Other Public Authority Service	1,138	123.64	14.6%
Rate FT-L – Firm Transportation Service	25,057	784.03	16.2%
Rate IT – Interruptible Transportation Service	63,341	1,007.75	14.9%
Rate IMBS – Interruptible Monthly Balancing Service *	88,398	237.79	24.5%

* IMBS revenues are credited to sales customer through the GCA.

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 30 days after publication of this notice of the proposed rate changes, request leave to intervene; intervention may be granted beyond the 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 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
Cost of Service Study Customer Component and Customer Charge Calculations

Line	Rate	(A) COSS Customer Component	(B) Test Period Customer Bills	(C) = (A) / (B) COSS Supported Customer Charge	(D) Proposed Customer Charge
1	RS	$ 35,525,915	1,130,041	$ 31.44	$ 19.00
2	GS	$ 5,082,039	84,032	$ 60.48	$ 58.00
3	FT-L	$ 353,802	1,092	$ 323.99	$ 430.00
4	IT	$ 155,286	264	$ 588.20	$ 430.00

Duke Energy Kentucky, Inc.

Weather Normalization Adjustment (WNA)

Report

May 2021

Introduction

When setting rates, the Company uses normalized levels of revenues and expenses for a test period, which is designed to be the most reasonable estimate of the Company's operations during the test period. These normalized revenues and expenses include the assumption of normal weather conditions to eliminate unusual weather related fluctuations in the test period that may otherwise cause rates to be set too high or too low. Specifically, test period weather related sales volumes reflect normal levels of heating degree days. (A heating degree day value is calculated by taking the difference between average daily temperature and a base temperature value). The average daily temperatures represent normal weather and are determined based on 30 years of past weather data.

However, normal weather rarely occurs which can cause customers' bills to fluctuate significantly from month to month and can result in the Company earning more or less than the authorized rate of return. To help reduce these fluctuations in customer bills and Company earnings, the Kentucky Public Service Commission approved the Weather Normalization Adjustment (WNA) in Case 2018-00261. The WNA mechanism adjusts the volumetric component of base delivery charges on customer bills to reflect normal weather conditions. Although customers use gas all year round, the largest portion of customer use and therefore largest share of the Company's revenue collection is dependent on heating load. Heating load generally occurs during the months of November through April (i.e., winter months) and, because it is highly correlated with temperature, can vary significantly when the temperature deviates from "normal." Under the WNA mechanism, when temperatures are colder than normal, volumetric sales will be higher than normal and the customer will receive a credit on their bill. When weather is warmer than normal, volumetric sales will be lower than normal; so, the customer's bill includes a surcharge. The result is that customers' bills during winter months should not fluctuate as significantly as they would without a WNA mechanism, and the Company should receive more normalized base revenues.

Adjustments were first made to customer's bills with Cycle 1 for November 2019. The WNA remains in effect each year from November through April. This report evaluates the results from the WNA Rider for the first two winters that it was in effect November 2019 – April 2020 and November 2020 – March 2021. Please note that the data for April 2021 was not yet available at the time of creating this report.

Weather

Overall, the weather for the winter of 2019/20 was warmer than normal, resulting in lower weather related gas sales than projected, although there were months that were colder than normal. The weather was similar for the 2020/21 winter. The table below shows the Actual HDD compared to Normal for each month of both winters. The HDD shown are the average of the HDD for each of the 21 billing cycles during that month, therefore weather from the previous month is also included. For example, Cycle 1 for a given month is mostly comprised of the previous month, while Cycle 21 is mostly the current month. The other cycles will be a mix of both months.

Billing Month	Normal HDD	Actual HDD	Variation	
Nov 19	243	288	18%	Colder
Dec 19	596	611	2%	Colder
Jan 20	846	608	28%	Warmer
Feb 20	790	662	16%	Warmer
Mar 20	604	553	8%	Warmer
Apr 20	293	269	8%	Warmer
Total Winter 19/20	**3,372**	**2,991**	**11%**	**Warmer**
Nov 20	239	209	12%	Warmer
Dec 20	614	536	13%	Warmer
Jan 21	855	790	8%	Warmer
Feb 21	790	872	11%	Colder
Mar 21	593	588	1%	Warmer
Apr 21				
Total Winter 20/21	**3,091**	**2,995**	**3%**	**Warmer**

Impact of WNA

As expected, customers received a surcharge when weather was warmer and a credit when weather was colder. The tables below show the impact of the WNA on Residential and Non-Residential customers.

Residential (Rate RS)

Billing Month	Number of Customers	WNA Surcharge/ (Credit)	Total Revenue	Percentage Impact of WNA
Nov 19	93,628	($323,743)	$4,910,709	-7%
Dec 19	94,179	($75,390)	$9,065,305	-1%
Jan 20	94,405	$1,746,315	$11,146,847	16%
Feb 20	94,534	$855,682	$10,713,487	8%
Mar 20	94,586	$335,601	$7,925,577	4%
Apr 20	94,565	$124,466	$4,960,690	3%
Total Winter 19/20		**$2,662,931**	**$48,722,615**	**5%**
Nov 20	94,836	$226,902	$4,757,748	5%
Dec 20	95,051	$501,993	$9,743,752	5%
Jan 21	95,293	$430,872	$13,002,635	3%
Feb 21	95,707	($608,293)	$12,883,748	-5%
Mar 21	95,605	$104,757	$9,463,083	1%
Apr 21				
Total Winter 20/21		**$656,230**	**$49,850,965**	**1%**

Non-Residential (Rate GS)

Billing Month	Number of Customers	WNA Surcharge/ (Credit)	Total Revenue	Percentage Impact of WNA
Nov 19	7,155	($95,730)	$1,789,607	-5%
Dec 19	7,314	($23,656)	$3,654,505	-1%
Jan 20	7,345	$563,408	$4,384,112	13%
Feb 20	7,348	$275,834	$4,178,023	7%
Mar 20	7,349	$112,196	$2,986,484	4%
Apr 20	7,282	$46,162	$1,703,297	3%
Total Winter 19/20		**$878,215**	**$18,696,029**	5%
Nov 20	7,120	$63,056	$1,558,428	4%
Dec 20	7,200	$159,537	$3,659,136	4%
Jan 21	7,275	$139,675	$4,999,211	3%
Feb 21	7,374	($195,525)	$5,161,856	-4%
Mar 21	7,351	$44,499	$3681,101	1%
Apr 21				
Total Winter 20/21		**$211,242**	**$19,059,732**	**1%**

Since winter weather makes month to month comparisons volatile by nature, comparing individual months year on year can better show WNA effect on volatility. The table below shows a comparison of total revenue for each month of Year 1 (November 2019 – April 2020) to the same month of Year 2 (November 2020 – April 2021) both with and without the effect of the WNA. As the table shows, there is a reduction in year to year volatility from 22% to 14%. The absolute value of the percentage change was used to calculate the average for each winter to eliminate the effect of offsetting year to year increases and decreases.

	Total Revenue with WNA			Total Revenue without WNA		
	Year 1	Year 2	Percent Change*	Year 1	Year 2	Percent Change*
November	$6,700,316	$6,316,176	6%	$7,119,789	$6,026,218	15%
December	$12,719,810	$13,402,887	5%	$12,818,856	$12,741,358	1%
January	$15,530,958	$18,001,846	16%	$13,221,236	$17,431,299	32%
February	$14,891,511	$18,045,604	21%	$13,759,994	$18,849,422	37%
March	$10,912,061	$13,144,184	20%	$10,464,264	$12,994,928	24%
April	$6,663,987			$6,493,359		
Avg Variance			**14%**			**22%**

* Absolute value of percentage change.

Customer Inquiries and Complaints

Tracking was set up to make note of the number of inquiries or complaints received from customer regarding the WNA. During the first winter there were 2 complaints and 4 inquiries. During the second winter there were no complaints or inquiries through March 2021.

	2019		2020		2021	
	Inquiry	Complaint	Inquiry	Complaint	Inquiry	Complaint
January			1	1	0	0
February			1	0	0	0
March			0	0	0	0
April			0	0		
May			0	0		
June			0	0		
July			0	0		
August	1	1	0	0		
September	0	0	0	0		
October	0	0	0	0		
November	1	0	0	0		
December	0	0	0	0		

Duke Energy Kentucky, Inc.
Calculation of Gas Service Reconnection Cost

Base Labor		$34.50	
Unproductive (time away - vacations, etc)	23.9%	$8.23	Loads on Base - direct labor
Incentives (annual bonuses)	3.2%	$1.38	Loads on Base plus Unprod
Subtotal		$9.61	
Fringes (benefits - health, retirement, etc)	40.1%		
Payroll Tax	6.9%		
Subtotal	46.9%	$20.70	Loads on Base plus Unprod plus Incentive
Fleet (cost of vehicles)	4.5%	$1.56	Loads on Base - direct labor
Loaded Labor w/ Fleet		$66.37	
Indirects (allocated costs of support functions)	69.0%	$45.81	Load on Loaded Labor
Total Cost Per Hour		$112.19	

	Approximate Hours	Cost
Gas Service Reconnection	1.00	$112.19
Contracted Rate for Gas Reconnection (Seasonal)		$90.25
Proposed Gas Service Reconnection Charge:		$90.00

Duke Energy Kentucky
Calculation of Meter Pulse Service Charges

Line No.	Equipment Descriptions	Cost
1	Installation of Meter Pulse Equipment:	
2	Pulser (1 of 2 options):	
3	Single Lead Metretek Pulser (#50116511):	$ 126.00
4	Dual Lead Metretek Pulser (#50130416):	$ 162.00
5	Average Pulser Cost (Average Lines 3 & 4)	$ 144.00
6	Intrinsically Safe Barriers (ISB)(1 of 2 options):	
7	115 Volt AC Power Option:	$ 330.00
8	24 Volt DC Power Option:	$ 300.00
9	Average ISB Cost (Average Lines 7 & 8)	$ 315.00
10	Weather-proof Box	$ 100.00
11	Total Average ISB Cost: (Line 9 + Line 10)	$ 415.00
12	Labor Hourly Rate	$ 128.04
13	Estimated hours	4.00
14	Total Labor (Line 12 x Line 13)	$ 512.16
15	Total Meter Pulse Equipment: (Line 5 + Line 11 + Line 14)	$ 1,071.16
16	Tariff Sheet Value Proposed: (Based on Line 15)	$ 1,000.00
17	Meter Index if needed (1 of 2 options):	
18	Life Lube Rotary Index (#50101099, #140013)	$ 566.00
19	Life Lube Rotary Index Conversion Kit	$ 588.00
20	Average Meter Index Cost	$ 577.00
21	Labor Hourly Rate	$ 128.04
22	Estimated hours	1.00
23	Total Labor (Line 21 x Line 22)	$ 128.04
24	Total Meter Index (Line 20 + Line 23)	$ 705.04
25	Tariff Sheet Value Proposed: (Based on Line 24)	$ 700.00

Duke Energy Kentucky
Pipeline Services
IT Balancing Charge Calculation based on Pipeline Rates Effective March 1, 2021

Charges based on Daily Balancing

				Annual Cost	
Demand Charges					
Columbia Gas FSS					
FSS MDWQ	4,600	$3.7300	12	$205,896.00	
Winter SST	4,600	$6.4280	6	$177,412.80	
Summer SST	2,300	$6.4280	6	$88,706.40	
Commodity Charges					
SST Inject *	340,282		$0.0169	$5,750.77	
FSS Inject	335,409		$0.0150	$5,031.14	
FSS Withdraw	331,932		$0.0150	$4,978.99	
SST Withdraw	327,179		$0.0158	$5,169.43	
KO ITS Commodity *	327,179		$0.0734	$24,014.95	
Total				$516,960.47	
Total IT & FT-L Annual Throughput 2020				3,955,965	mcf
Cost for Daily Balancing (All Options)				**$0.1307**	**per mcf**

Charges Based on Carry-Over Amounts

Columbia Gas FSS					
FSS SCQ Summer (8%)	6,586	$0.0672	7	$3,098.15	
FSS SCQ Winter (10%)	8,233	$0.0672	5	$2,766.20	
				$5,864.35	
Total Option 3 Annual Throughput				987,929	mcf
Charge for Monthly Carry-over				**$0.0059**	**per mcf**
Total Charge for Option 3				**$0.1366**	**per mcf**

* Commodity Charges include ACA of $0.0011

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 Natural Gas Rates; 2) Approval of New Tariffs; and 3) All Other Required Approvals, Waivers, and Relief.	)))))	Case No. 2021-00190

DIRECT TESTIMONY OF

SARAH E. LAWLER

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

June 1, 2021

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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 and other regulatory commissions.

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 natural gas base revenues and the drivers behind the Company's application. I also support other requests including the reasonableness of calculating the Company's natural gas base rates on its rate base. I support the reasonableness of the Company's proposed rate increase and sponsor Filing Requirement (FR) 16(1)(b)(1) to comply with the Commission's filing requirements. Finally, I support the Company's proposal to implement a governmental mandate adjustment mechanism (Rider GMA) which will enable the

Company to implement and respond to governmental directives/mandates impacting the utility.

II. BACKGROUND AND DRIVERS FOR REQUESTED RATE INCREASE

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

A. The Company's current base rates for natural gas service were approved by the Commission on March 27, 2019, in Case No. 2018-00261 (2018 Rate Case). The test period in that proceeding was the forecasted twelve months ended March 31, 2020, and the rate base and capitalization used in that case was the thirteen-month average for the period ending March 31, 2020. The current rates went into effect on March 29, 2019.

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 natural gas base revenues based on the forecasted twelve-month period January 1, 2022 through December 31, 2022.

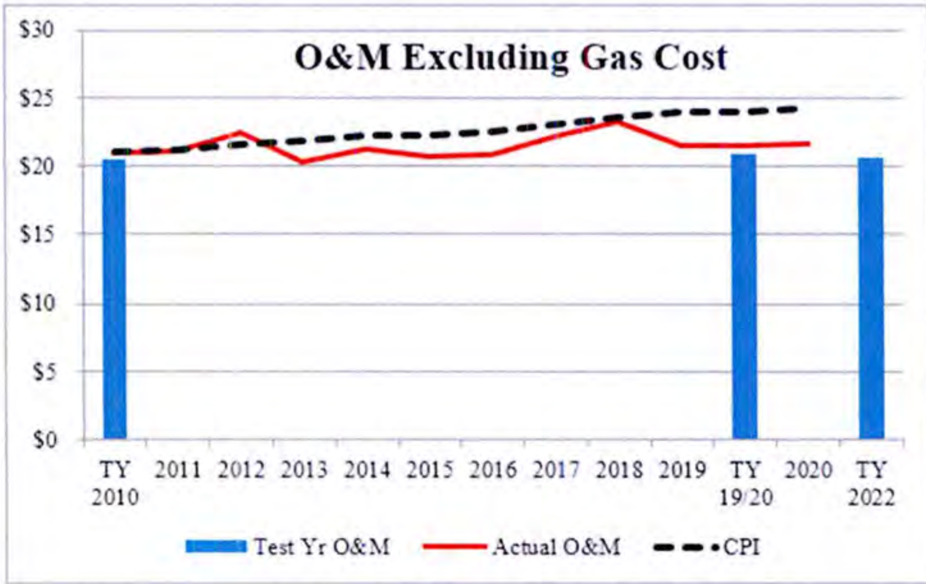
Q. WHY IS DUKE ENERGY KENTUCKY FILING A NATURAL GAS BASE RATE CASE AT THIS TIME?

A. For the forecasted test period, the Company is projecting that the earned return on its investment in its natural gas system is not providing fair and reasonable compensation to its investors. As a result, the Company is requesting an approximate $15 million increase in natural gas base revenues in order to provide fair and reasonable compensation to its investors.

Since the time of the last natural gas base rate case, the Company has made significant capital investments in its natural gas delivery system infrastructure. The thirteen-month average of gross utility plant in the 2018 Rate Case was approximately $589 million. The thirteen-month average of gross utility plant in the forecasted test period for this case is $772 million. This represents an increase of approximately $183 million in gross utility plant and results in an approximate $155 million increase in rate base. The return on this increased rate base translates into an increased revenue requirement of approximately $14 million. That increased return and the associated approximate $5 million in increased depreciation and property taxes are the primary drivers of the need for new customer rates. These increases are partially offset by approximately $4 million related to modest customer growth and slightly higher customer usage. Importantly, the Company has diligently controlled its operation and maintenance (O&M) expenses since the 2018 Rate Case. This effort to control costs through efficiency and productivity gains has helped the Company mitigate the impact of the proposed rate increase in this case.

Q. PLEASE QUANTIFY THE COMPANY'S SUCCESS IN CONTROLLING ITS O&M EXPENSE SINCE ITS LAST NATURAL GAS BASE RATE CASE.

A. The chart below best demonstrates the fact that the Company has successfully controlled its O&M costs over the last twelve years. The bars represent the Company's test year O&M expense in its 2009 Rate Case, O&M expense approved in the 2018 Rate Case and that projected in this current case, respectfully. The horizontal line shows the Company's O&M, as reported in its Annual Reports filed with the Commission. As this chart shows, the Company's O&M expense has remained relatively flat for the last twelve years and has remained below the rate of inflation. Importantly, O&M expenses included in customer rates have also remained below the rate of inflation and either flat or lower than actual O&M expense for the last twelve years.



The Company's efforts at managing its costs have enabled it to maintain natural gas customer rates that are competitive with our peer natural gas utilities operating within the Commonwealth of Kentucky.

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

A. No. Since the 2018 Rate Case, the cost of capital has decreased slightly. The Company's current weighted average cost of capital approved in the 2018 Rate Case is 7.063%. The Company is requesting a weighted average cost of capital of 7.060% in this current proceeding. Although the last case was settled with a specified 9.7 percent return on equity, even with the return on equity of 10.30 percent being proposed in this case, the overall rate of return being requested in this case is lower than the rate of return settled upon in the 2018 Rate Case. This is being driven by the lower cost of debt, both short term and long term. The Company's long-term debt rate included in the approved rate of return in the 2018 Rate Case was 4.36 percent. The long-term debt interest rate for the forecasted test period in this case has fallen to 3.84 percent. The Company's short-term debt rate included in the approved rate of return was 4.25%. The short-term debt interest rate for the forecasted test period in this case has fallen to 1.67%. The 2018 Rate Case included a capital structure of just under 51 percent equity which is consistent with that being requested in this case.

Q. PLEASE EXPLAIN DUKE ENERGY KENTUCKY'S CONTINUED USE OF RATE BASE TO DETERMINE RATES IN THIS PROCEEDING.

A. Rate base represents the actual value of the physical plant used to provide utility service to customers. The Commission has the option to provide its regulated utilities a return on its capitalization supporting the rate base or to simply use rate base. The Commission authorized Duke Energy Kentucky to use the rate base approach to determine its natural gas base rates as part of the 2018 Rate Case. The Commission also authorized Duke Energy Kentucky to use the rate base approach to determine its electric base rates in the Company's most recent electric base rate case. The Company is proposing to continue using that approach in this proceeding.

Q. HAS THE COMPANY QUANTIFIED THE DIFFERENCE BETWEEN ESTABLISHING NATURAL GAS BASE RATES THROUGH A RETURN ON CAPITALIZATION VERSUS THE RATE BASE METHODOLOGY?

A. The filing requirements applicable to this case require a reconciliation of rate base to capitalization, FR 16(6)(f). In this case, the estimated capitalization is higher than the rate base; so, applying a return to a higher basis would produce a higher revenue requirement. In this case, using capitalization instead of rate base would produce a revenue requirement that is approximately $1 million higher on an annual basis than the amount the Company is seeking by using rate base. Attachment SEL-1 shows the summary revenue requirement calculation, from Schedule A of the Application, using rate base in one column and capitalization in the other. In this case, using rate base produces a lower overall revenue requirement than using capitalization.

III. GOVERNMENTAL MANDATE ADJUSTMENT MECHANISM

Q. PLESE DESCRIBE THE COMPANY'S PROPOSAL TO CREATE A GOVERNMENTAL MANDATE ADJUSTMENT MECHANISM (RIDER GMA).

A. Duke Energy Kentucky is proposing to implement Rider GMA as part of this proceeding. The rider corresponds to the Company's obligation to adhere to governmental directives or mandates impacting the utility that are outside of its control. These mandates include changes in federal or state income tax rates, and those promulgated by federal governmental entities and agencies that require the Company to upgrade or replace our natural gas delivery infrastructure. Rider GMA would act as either a credit or a charge to customers, depending upon the impact of the governmental mandate. Duke Energy Kentucky's proposed Rider GMA will be applicable to all natural gas customers.

Q. PLEASE EXPLAIN HOW THE COMPANY PLANS TO INCLUDE CHANGES IN FEDERAL OR STATE INCOME TAX RATES IN THE RIDER GMA.

A. The Company proposes to include in Rider GMA any change in its cost of service resulting from increases or decrease in federal or state income tax expense resulting from changes in federal or state income tax rates. The Company would revise the revenue requirement calculation agreed upon in its most recently approved natural gas base rate case by updating the federal and/or state income tax rates. The resulting change in revenue requirement (either positive or negative depending on whether it resulted from a tax rate increase or decrease) would be included in Rider GMA for recovery from or credit to all natural gas customers.

The Company also proposes to include any changes in amortization of unprotected excess or deficient deferred income taxes in the Rider GMA. Because of the IRS tax normalization rules outlined in Company witness John R. Panizza's testimony, any changes in amortization of protected excess or deficient deferred income taxes would not be included in Rider GMA, but rather updated in the company's next natural gas base rate case.

Q. PLEASE EXPLAIN WHAT COSTS ASSOCIATED WITH UPGRADES OR REPLACEMENTS TO NATURAL GAS INFRASTRUCTURE THE COMPANY PROPOSES TO INCLUDE IN RIDER GMA.

A. As outlined in Company witnesses Amy B. Spiller's and Brian R. Weisker's testimony, the Company proposes to include costs associated with compliance with regulations issued by the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration in Rider GMA. The Company would calculate a revenue requirement to recover a return on the rate base associated with these incremental capital costs along with recovery of the associated depreciation and property tax expenses. Rate base would be calculated as gross plant in-service less accumulated depreciation less accumulated deferred income taxes associated with the plant in-service. The Company is not proposing to include any O&M expenses associated with these projects in Rider GMA. Any incremental O&M incurred would be proposed for recovery from customers in the Company's next natural gas base rate case.

Q. PLEASE EXPLAIN HOW THE COMPANY PROPOSES TO IMPLEMENT RIDER GMA.

A. Upon approval of the tariff and mechanism in this proceeding, Duke Energy Kentucky will file a separate application to implement any adjustments to Rider GMA in response to a governmental mandate. This application would be subject to Commission determination of prudence and reasonableness. Significant pipeline replacement projects required by a government mandate but that do not constitute an ordinary extension of the existing system in the ordinary course of business would be accompanied by a certificate of public convenience and necessity (CPCN). Rider GMA charges or credits will not appear on a customer's bill until such applications are approved by the Commission. Going forward, the Company will make annual applications with the Commission to update Rider GMA, reflecting any new proposed capital projects and the depreciation of previously approved capital projects as well as any changes to federal and state income tax rates or changes to the amortization of unprotected excess or deficient deferred income taxes. The revenue requirement would then be allocated to customer classes consistent with the cost of service study approved in the Company's most recent natural gas base rate case.

Q. HOW DOES THE COMPANY PROPOSE TO CALCULATE THE RETURN ON CAPITAL INVESTMENTS INCLUDED IN RIDER GMA?

A. The Company proposes to calculate the return on any incremental capital investments associated with a government mandate at the weighted average cost of capital approved in the Company's most recent natural gas base rate case.

Q. HOW WILL CUSTOMERS BE CHARGED OR CREDITED UNDER THIS MECHANISM?

A. As outlined in the proposed tariff supported by Company witness Jeff L. Kern, customers taking service under rates RS and GS would be charged or credited a fixed monthly charge. Customers taking service under rates FT-L and IT would be charged or credited on a volumetric per ccf basis.

IV. REASONABLENESS OF REQUEST

Q. DO YOU BELIEVE THE COMPANY'S REQUESTED RATE RELIEF REASONABLE?

A. Yes. Duke Energy Kentucky has done a good job of keeping its expenses down over the years; however, the need to continually invest it its natural gas delivery system creates a need for the Company to seek additional rate relief. In addition, the use of rate base for calculating the Company's revenue requirement is reasonable and consistent with prior Commission precedent. Finally, the approval of Rider GMA will allow the Company to recover its prudently incurred and reasonable pipeline replacement costs necessary to comply with governmental directives and to implement changes in taxes directed by either the Federal or State government. This ensures that customers are paying no more and no less than the actual costs.

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.

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 natural gas 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. WERE ATTACHMENTS SEL-1 AND FR 16(1)(b)(1) PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

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

A. Yes.

Duke Energy Kentucky, Inc.
Case No. 2021-00190
Overall Financial Summary

Line No.	Description	Jurisdictional Revenue Requirements Forecasted Period Rate Base	Jurisdictional Revenue Requirements Forecasted Period Capitalization
1	Basis for Return Component	$468,321,206	$479,499,181
2	Operating Income	$21,653,814	$21,705,038
3	Earned Rate of Return (Line 2 / Line 1)	4.620%	4.530%
4	Required Rate of Return	7.060%	7.060%
5	Required Operating Income (Line 1 x Line 4)	$33,063,477	$33,852,642
6	Operating Income Deficiency (Line 5 - Line 2)	$11,409,663	$12,147,604
7	Gross Revenue Conversion Factor	1.3346730	1.3346730
8	Revenue Deficiency (Line 6 x Line 7)	$15,228,169	$16,213,079

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 Natural Gas Rates; 2) Approval of New Tariffs; and 3) All Other Required Approvals, Waivers, and Relief.	))))))	Case No. 2021-00190

DIRECT TESTIMONY OF

BRYAN T. MANGES

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

June 1, 2021

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bryan T. Manges and my business address is 4720 Piedmont Row Dr., Charlotte, North Carolina 28210.

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

A. I am employed by Duke Energy Business Services LLC (DEBS), as Director, Gas Utilities & Infrastructure Accounting. 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 have a Bachelor of Science in Accounting from Clemson University and a Master's in Business Administration from The University of North Carolina at Charlotte. I am a Certified Public Accountant (CPA) in North Carolina. I was the Director of Corporate Accounting at Piedmont Natural Gas prior to Duke's acquisition of Piedmont in 2016 and transitioned to my current role shortly after the acquisition. I had been at Piedmont since 2008 in various positions in Accounting and Legal. At present, my title is Director, Gas Utilities & Infrastructure Accounting. I am responsible for revenue accounting, gas accounting, and general accounting and reporting for Duke Energy's natural gas segment.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR, GAS UTILITIES & INFRASTRUCTURE ACCOUNTING.

A. As Director, Gas Utilities & Infrastructure Accounting, I am responsible for the books of account and reporting the financial position and the results for the Gas Segment within Duke Energy including Duke Energy Kentucky's gas operations as well as Duke Energy Ohio's gas operations, Piedmont Natural Gas and various gas pipeline development projects within the segment.

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 in this proceeding addresses the various capital and operating expenditures and accounting adjustments to Duke Energy Kentucky's books of account in support of Duke Energy Kentucky's application in this proceeding. I sponsor the historic data in Schedule B-8 provided in satisfaction of Filing Requirement FR 16(8)(b); and Filing Requirements FR 12(2)(i), FR 16(7)(i), FR 16(7)(k), FR 16(7)(m), FR 16(7)(n), FR 16(7)(o), FR 16(7)(p), and FR 16(7)(q). Finally, I also sponsor the historic data on Schedules I-1 through I-5 in response to FR 16(8)(i), and Schedule K in response to FR 16(8)(k).

II. OVERVIEW OF DUKE ENERGY KENTUCKY'S ACCOUNTING RECORDS

Q. ARE YOU FAMILIAR WITH THE ACCOUNTING PROCEDURES AND BOOKS OF ACCOUNT OF DUKE ENERGY KENTUCKY?

A. Yes. The books of account for Duke Energy Kentucky's regulated business follow the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC).

Q. ARE THE BOOKS OF ACCOUNT FOR THE NATURAL GAS BUSINESS OF DUKE ENERGY KENTUCKY PREPARED AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes.

Q. ARE THE CAPITAL AND OPERATING EXPENDITURES REPRESENTED ON DUKE ENERGY KENTUCKY'S BOOKS OF ACCOUNT ACCURATE AND REASONABLE?

A. Yes. Duke Energy Kentucky has various budgeting, planning, and review procedures in place to establish and monitor the capital and operating budgets, as well as actual expenditures. The system of internal accounting controls provides reasonable assurance that all transactions are executed in accordance with management's authorization and are recorded properly.

The system of internal accounting controls is annually reviewed, tested, and documented by Duke Energy Kentucky to provide reasonable assurance that amounts recorded on the books and records of the Company are accurate and proper. In addition, independent certified public accountants perform an annual audit to provide assurance that internal accounting controls are operating effectively and that Duke Energy Kentucky's financial statements are materially accurate. Duke Energy Kentucky will continue recording deferrals, per normal regulatory accounting standards, for riders that are subject to being trued-up. Over- or under-recovery of costs are flowed through riders such as the gas cost adjustment clause; the Company records the amounts to be trued-up in future periods as regulatory assets or regulatory liabilities.

III. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE B-8.

A. Schedule B-8 contains the Comparative Balance Sheets for Duke Energy Kentucky for the most recent five calendar years, the base period and the forecasted period.

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

A. FR 12(2)(i) consists of Duke Energy Kentucky's detailed income statement and balance sheet for the period ended March 31, 2021.

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

A. FR 16(7)(i) consists of the Company's most recent Federal Energy Regulatory Commission (FERC) audit report, reporting the results of the Company's last FERC audit.

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

A. FR 16(7)(k) consists of Duke Energy Kentucky's most recent FERC Form 1 and FERC Form 2.

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

A. FR 16(7)(m) consists of Duke Energy Kentucky's current chart of accounts.

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

A. FR 16(7)(n) consists of the latest twelve months of the monthly management reports providing financial results of the Company's operations in comparison to the forecast.

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

A. FR 16(7)(o) consists of management's monthly budget variance reports for Duke Energy Kentucky natural gas operations.

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

A. FR 16(7)(p) consists of Duke Energy's most recent Form 10-K and Form 8-K as well as those forms for the last two years. Additionally, the Company is submitting copies of its Form 10-Qs that were filed during the past six quarters.

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

A. FR 16(7)(q) consists of the independent auditor's annual opinion report for Duke Energy Kentucky. The auditor did not note any material weaknesses in internal controls.

Q. PLEASE DESCRIBE THE INFORMATION YOU SUPPORT IN RESPONSE TO FR 16(8)(i), 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 historic information contained on these schedules.

Q. PLEASE DESCRIBE THE INFORMATION YOU SUPPORT IN RESPONSE TO FR 16(8)(k), THE K SCHEDULE.

A. The information I support in response to FR 16(8)(k) consists of the Consolidated Condensed Income Statement and other Comparative Financial Data as presented on pages 2, 4 and 5 of Schedule K for Duke Energy Kentucky. I provided this information to Ms. Motsinger for her use in preparation of the forecast.

IV. CONCLUSION

Q. WAS THE INFORMATION YOU SPONSORED IN SCHEDULES B-8, I-1, I-2.1, I-3, I-4, I-5 AND K AS WELL AS FR 12(2)(i), FR 16(7)(i), FR 16(7)(k), FR 16(7)(m), FR 16(7)(n), FR 16(7)(o), FR 16(7)(p), FR 16(7)(q), FR16(8)(i), AND FR 16(8)(k) PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

Q. IS THE INFORMATION YOU SPONSORED 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.

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 Natural Gas Rates; 2) Approval of New Tariffs; and 3) All Other Required Approvals and Relief.	)))))	Case No. 2021-00190

DIRECT TESTIMONY OF

ABBY L. MOTSINGER

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

June 1, 2021

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Abby L. Motsinger and my business address is 550 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, Jurisdictional 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 Business Administration degree in Finance from the University of Notre Dame, and a Masters of Accountancy degree from the University of North Carolina at Chapel Hill. In 2010, I joined Duke Energy as a senior Accounting Analyst in the Midwest Wholesale Accounting department. Subsequently, I held various positions of increasing responsibility within the Accounting department, including the Benefits and SEC Reporting groups. In 2017, I became Investor Relations Manager. In May 2021, I became Director, Jurisdictional Forecasting within the Financial Planning and Analysis Department.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS DIRECTOR, JURISDICTIONAL FORECASTING.

A. I am responsible for overseeing the preparation of financial forecasts and other financial analysis for Duke Energy's electric utilities, in addition to Duke Energy's Midwest gas utilities including Duke Energy Kentucky and Duke Energy Ohio.

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

A. No.

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

A. My testimony describes the 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 the direction and control of the Financial Planning and Analysis department. I sponsor Filing Requirements (FR) 16(6)(a), 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 sponsor certain information contained 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 that are co-sponsored by Duke Energy Kentucky witness David Raiford. I sponsor the information contained in B-5 and B-5.1 and certain information contained in

Schedule B-8 that is also supported by Duke Energy Kentucky witness Mr. Bryan Manges. In response to FR 16(6)(a), 16(6)(b) and 16(8)(d), I sponsor Schedules D-2.1 through D-2.14, and D-2.25. I also sponsor the forecasted data on Schedules I-1 through I-5 in response to FR 16(8)(i), and 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 2020 actual data and its 2021 annual budget. This is because the Company is using a base period that spans two calendar years and is comprised of actual data for 2020 and both actual and budgeted data for 2021. The Company is also using a fully forecasted test period that, for this proceeding, spans the twelve-month period ending December 31, 2022. 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 occur 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 2021 ANNUAL BUDGET RESULTS FOR THE BASE AND FORECASTED PERIODS IN THIS PROCEEDING?

A. The base period is the twelve months ending August 31, 2021 and consists of six months of actual data through February 2021 and the remaining six months of budgeted data. The forecasted test period is the twelve months ending December

31, 2022. The Company's 2020 actual data and 2021 budget was 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 2021 annual budget for a limited number of updated assumptions. Next, I extended the revised 2021 budget to December 31, 2022 using the Company's standard forecasting methodology, which I describe later in my testimony when I explain how I prepared the financial forecasts. Finally, I updated the revised budget and the forecasted test period with actual data through February 2021.

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 Budgeting and Business Support 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 BUDGETING AND BUSINESS SUPPORT ORGANIZATION IN DEVELOPING DUKE ENERGY KENTUCKY'S ANNUAL RESPONSIBILITY (OPERATING AND MAINTENANCE) CENTER BUDGET.

A. The guidelines provided by the business support 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 and information technology expenses, are included. There are instructions for handling contract labor and supplies. 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 purchased natural gas and other natural gas supply costs;

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, accounts receivable sales 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 2021 annual budget was to obtain a forecast of the projected natural gas sales on a thousand cubic feet basis (MCF) from Duke Energy Kentucky witness Benjamin Walter Bohdan Passty, Ph.D., 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 number of customers for each customer class. The projected revenues for the annual budget and the long-range forecast for MCF sales were calculated by applying the tariff charges to these sales forecast numbers for all natural gas residential customers. The projected revenue for natural gas non-residential customers was calculated by applying average realizations to their respective MCF sales forecasts.

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

A. Yes. As described by Dr. Passty, 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 reconnection charges, minimum use contract revenues *etc.*, for Duke Energy Kentucky's 2021 and 2022 annual budgets are projected based on historical trends or are provided by the individual budget centers.

Q. HOW DID YOU OBTAIN THE PURCHASED NATURAL GAS EXPENSE FOR THE INCOME STATEMENT PORTION OF THE ANNUAL BUDGET?

A. The level of purchased gas expense is derived from the projected cost per unit of the natural gas consumed and the volume of the consumption determined by the natural gas sales forecasts. Duke Energy Kentucky witness Mr. Brian Weisker provided the natural gas supply mixture and purchased natural gas expense.

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

A. The forecasted depreciation for current and projected new natural gas plant was calculated by multiplying the original cost of current and projected new natural gas plant by the Company account level depreciation rates from Schedule B-3.2. This calculation was performed for the base and forecasted periods. Duke Energy Kentucky witness Mr. David Raiford provided me with the actual balances of the current natural gas plant along with the current depreciation rates. Then the Natural Gas Business Unit works with operational teams and provides budgeted capital expenditures. A similar process was used to obtain the depreciation expense for the five-year forecast, using budgeted capital expenditures.

Q. DESCRIBE HOW OPERATION AND MAINTENANCE EXPENSES ARE INCLUDED IN THE FORECAST.

A. The O&M expenses, including benefits and payroll taxes, were obtained from the 2021 annual budget 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, Mr. Jeff Setser. For labor-related expenses, I used the projected annual labor cost rate increases provided by Duke Energy Kentucky witness Mr. Jake Stewart to budget 2021 and 2022 union and non-union employee labor expense. Union labor cost increases were assumed to be between 1 percent and 3 percent, depending on the agreements. For 2021, non-union labor cost increases were reduced from 3.5 to 2.5 percent due to COVID (including both merit increases of 2 percent and an allowance for salary increases for promotions of 0.5 percent). Non-union labor cost increases are assumed to return to 3.5 percent in 2022 (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 (25.70 percent for 2021 and 2022) and payroll tax (7.65 percent in each year) loadings. Non-labor expenses for 2021 and 2022 were forecasted by the responsibility centers based on their knowledge and expectations for various costs.

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

A. As mentioned above, O&M budgets were supplied by the responsibility centers for 2021 and 2022 per the company's Budget Guidelines. The basis for the 2022 budget is the 2021 budget adjusted for various O&M expenses that are expected to diverge from that budget in 2022.

Q. HOW DID YOU OBTAIN PROPERTY TAX EXPENSE?

A. The property tax expense was obtained from the 2021 annual budget and was prepared as described by Duke Energy's Tax Department. Duke Energy Kentucky witness Mr. John Panizza supplied the property tax expenses for the forecasted financial test period data, based on the capital projections.

Q. HOW DID YOU OBTAIN INTEREST EXPENSE?

A. Duke Energy's Treasury Department provided the long-term debt balances and long- and short-term interest rates for the 2021 annual budget and the 2022 forecast.

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

A. "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 capital forecasts prepared for the 2021 annual budget.

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 Deferred Income Taxes (EDITs). The income tax expense was derived using Utilities International (UI) Planner or "proprietary forecasting" software for each month of the 2021 annual budget period and the 2022 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 February 2021 balances. Duke Energy Kentucky witness, Mr. Raiford supplied the net book value for the existing natural gas and common plant and construction work in progress for the period ending February 2021. I used the proprietary forecasting software to calculate the depreciation expense and net natural gas 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. Weisker 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 2021 annual budget and was completed for a five-year period as typically done.

The other assumptions were the dividend policy, the projected changes in long-term debt, the amount of capital lease and equipment lease payments, and the sale of accounts receivable for both the 2021 annual budget and the 2022 forecasts.

C. CASH FLOW STATEMENT

Q. HOW DID YOU PREPARE THE CASH FLOW STATEMENT FOR THE 2021 ANNUAL BUDGET?

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, Jurisdictional 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.

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. Mr. Raiford provided me with the actual data that I used to compile the forecasted data contained in these schedules.

Q. PLEASE DESCRIBE SCHEDULE B-5.

A. Schedule B-5 is a summary of the jurisdictional working capital calculation based on the Commission's traditional methodology. The calculation includes inventory balances and prepayments.

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 natural gas working capital for the forecasted test period is $422,179.

Q. PLEASE EXPLAIN THE GAS ENRICHERS LIQUIDS AND GAS STORED UNDERGROUND INVENTORIES ON SCHEDULE B-5.1.

A. The gas enricher liquids and gas stored underground 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 gas enricher liquids and gas stored underground inventories included in natural gas working capital for the forecasted test period are $1,785,156 and $1,692,954, respectively.

Q. PLEASE DESCRIBE THE B-8 SCHEDULE AND THE INFORMATION YOU SUPPORT.

A. Schedule B-8 is the comparative balance sheet. I sponsor the forecasted data contained in 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 increase of $5,444,770.

Q. PLEASE DESCRIBE SCHEDULE D-2.2.

A. Schedule D-2.2 adjusts base period purchased gas cost expenses to the level included in the forecasted test period. The effect of the adjustment on Duke Energy Kentucky's natural gas operations is an increase in pre-tax operating expenses of $5,070,846.

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 gas operations is a decrease in pre-tax operating expenses of $87,408.

Q. PLEASE DESCRIBE SCHEDULE D-2.4.

A. Schedule D-2.4 adjusts the base period for other gas supply expense to the forecasted period. The effect of the adjustment on natural gas operations is a decrease in pre-tax operating expenses of $26,660.

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 natural gas operations is an increase in pre-tax operating expenses of $115,162.

Q. PLEASE DESCRIBE SCHEDULE D-2.6.

A. Schedule D-2.6 adjusts base period distribution expenses to the level included in the forecasted test period. The effect of the adjustment on natural gas operations is an increase in pre-tax operating expenses of $337,547.

Q. PLEASE DESCRIBE SCHEDULE D-2.7.

A. Schedule D-2.7 adjusts base period customer accounts expenses to the level included in the forecasted test period. The effect of the adjustment on natural gas operations is an increase in pre-tax operating expenses of $1,990,460.

Q. PLEASE DESCRIBE SCHEDULE D-2.8.

A. Schedule D-2.8 adjusts base period customer service and information expenses to the level included in the forecasted test period. The effect of the adjustment on natural gas operations is an increase in pre-tax operating expenses of $43,843.

Q. PLEASE DESCRIBE SCHEDULE D-2.9.

A. Schedule D-2.9 adjusts base period sales expense to the level included in the forecasted test period. The effect of the adjustment on natural gas operations is an increase in pre-tax operating expenses of $47,036.

Q. PLEASE DESCRIBE SCHEDULE D-2.10.

A. Schedule D-2.10 adjusts base period administrative and general expenses to the level included in the forecasted test period. The effect of the adjustment on natural gas operations is a decrease in pre-tax operating expenses of $1,203,155.

Q. PLEASE DESCRIBE SCHEDULE D-2.11.

A. Schedule D-2.11 adjusts base period other operating expenses to the level included in the forecasted test period. The effect of the adjustment on natural gas operations is a decrease of pre-tax operating expenses of $1,489,563.

Q. PLEASE DESCRIBE SCHEDULE D-2.12.

A. Schedule D-2.12 adjusts base period depreciation expense to the level included in the forecasted test period. The effect of the adjustment on natural gas operations is an increase in pre-tax operating expenses of $665,032.

Q. PLEASE DESCRIBE SCHEDULE D-2.13.

A. Schedule D-2.13 adjusts base period taxes other than income taxes to the level included in the forecasted test period. The effect of the adjustment on natural gas operations is an increase in pre-tax operating expenses of $664,213.

Q. PLEASE DESCRIBE SCHEDULE D-2.14.

A. Schedule D-2.14 adjusts base period income taxes to the level included in the forecasted test period. The effect of the adjustment on natural gas operations is an increase in income tax expense of $505.

Q. PLEASE DESCRIBE SCHEDULE D-2.25.

A. Schedule D-2.25 is an adjustment to annualize revenue in the forecasted test period. The overall effect of the adjustment on natural gas operations is to decrease revenues in the forecasted test period by $515,124.

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.

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 condensed income statement, on page 2, and the mix of sales and fuel on page 5, for the base period and the forecasted test period.

X. CONCLUSION

Q. WAS THE INFORMATION YOU SPONSOR IN FR 16(6)(a), 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), 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, B-5,B-5.1, AND B-8, D-2.1 THRU D-2.14, AND D-2.25, 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 Natural Gas Rates; 2) Approval of New Tariffs; and 3) All Other Required Approvals, Waivers, and Relief.	))))))	Case No. 2021-00190

DIRECT TESTIMONY OF

JOHN R. PANIZZA

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

June 1, 2021

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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 550 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 prepares and files federal, state, and local income tax returns for Duke Energy. The department also files tax returns for various joint ventures if Duke Energy is the designated tax matters partner.

The Tax Department maintains and reconciles Duke Energy's tax accounts and is responsible 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. I provided testimony in Case No. 2019-00271, Duke Energy Kentucky's last electric base rate case proceeding and Case No. 2018-00261, Duke Energy Kentucky's last natural gas base rate case proceeding.

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 discuss the impact of the Tax Cuts and Job's Act (Tax Act) on Duke Energy Kentucky's natural gas operations. 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 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 excess deferred income taxes.

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% jurisdictional, this schedule is not applicable.

Q. WHAT TAX INFORMATION DID YOU PROVIDE TO OTHER WITNESSES?

A. I provided Duke Energy Kentucky witness Ms. Abby L. Motsinger 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 Ms. Motsinger and Mr. Brown with the income tax rates and the amortization of the investment tax credit and EDITs for both the forecasted portion of the base period consisting of the six months ending August 31, 2021, and the forecasted test period ending December 31, 2022.

I reviewed Ms. Motsinger and Mr. Brown's calculation of deferred income taxes for the base period and the forecasted period, I provided the amount of tax depreciation she used for this calculation, and I support the methodology she used for calculating deferred income taxes.

III. TAX ACT

Q. PLEASE BRIEFLY DESCRIBE THE TAX ACT.

A. On December 22, 2017, President Donald Trump signed the Tax Act into Law. This legislation represents the most significant revision to the Federal Tax Code in the last thirty years. The voluminous Tax Act brought comprehensive change to the individual, corporate and international tax law. The headline change to the corporate tax code was a reduction of the statutory corporate tax rate from 35 percent to 21 percent, but this reduction in rate was accompanied by many other provisions that serve to broaden the tax base and to "pay for" the effect of the 21 percent tax rate. Most provisions of the Tax Act took effect beginning January 1, 2018.

Q. WHAT WAS THE PURPOSE BEHIND THE PASSAGE OF THE TAX ACT?

A. The purpose of the Tax Act was to stimulate business investments, create jobs and grow the economy. An expectation that the financial health of the Company be unharmed by tax reform is reasonable and is consistent with these policy objectives and serves as a theme of my testimony.

Q. WHAT WERE THE KEY PROVISIONS OF THE TAX ACT AS IT RELATES TO DUKE ENERGY KENTUCKY?

A. Most changes to the corporate tax code apply to all U.S. corporations equally; while a limited set of others affect regulated utilities uniquely. For utilities in general, and for Duke Energy Kentucky in particular, the key provisions of the Tax Act that affect customer rates are as follows: (1) reduction of the corporate tax rate from 35 percent to 21 percent; (2) retention of net interest expense deductibility; (3) elimination of bonus depreciation; (4) elimination of the manufacturing deduction; and (5) normalization of EDITs resulting from the Tax Act.

Q. HAS DUKE ENERGY KENTUCKY INCORPORATED THE IMPACTS OF THE TAX ACT IN ITS RATES?

A. Yes. In its last natural gas base rate case, Case No. 2018-00261, Duke Energy Kentucky incorporated the impacts of the Tax Act into its natural gas base rates. In this case, the Company is not proposing any changes.

Q. HAS THE COMPANY QUANTIFIED THE REMAINING BALANCE OF THE PROTECTED AND UNPROTECTED EDITS FOR NATURAL GAS OPERATIONS?

A. Yes. The total projected balance of the EDITs for the Company's natural gas operations as of December 31, 2022 before ratemaking adjustments is as follows:

Protected EDITs (Federal)	$30,377,496
Unprotected EDITs (Federal)	$ 169,028
Unprotected EDITs (State)	$ 409,562
Total EDITs	$30,956,086

As discussed in the testimony of Company witness Jay P. Brown, an adjustment of $1,686,110 was made to the EDIT balances resulting in a final EDIT balance of $29,269,976. The protected EDITs represent the remeasurement of property related deferred tax liabilities resulting from accelerated tax depreciation and the balance is prorated as required by the tax normalization rules set forth in Treasury Regulation §1.167(l)-1. The unprotected EDITs (Federal)represent the remeasurement of all other property and non-property related deferred tax liabilities and assets and the balance is based on a 13-month average of the test period. The Unprotected EDITs (State) represent the remeasurement of state deferred taxes as a result of the reduction of the Kentucky state income tax rate from 6% to 5% and the balance is based on a 13-month average of the test period.

Q. PLEASE EXPLAIN HOW THE COMPANY IS PROPOSING TO ADDRESS POTENTIAL FUTURE CHANGES TO THE FEDERAL OR STATE CORPORATE INCOME TAX RATE?

A. As part of this proceeding, the Company is proposing a new mechanism, the Governmental Mandate Adjustment (Rider GMA) that, among other things, will be used to address any future changes in the federal or state income tax rate. Duke Energy Kentucky witness Sarah E. Lawler explains in her Direct Testimony the mechanics of Rider GMA. As it relates to changes in income tax rates, to the extent the new administration acts on its desire to increase the corporate tax rate from its current 21 percent, the Rider GMA will allow the Company to collect the incremental difference and also adjust the unprotected balances of the EDITs that are currently included in natural gas base rates to ensure the Company is recovering the correct amount of taxes. An increase in the corporate tax rate from the current 21 percent would mean that the income tax expense included in base rates is understated and the current level of EDITs calculated for customers has been overstated. Just as the Commission determined that Duke Energy Kentucky's natural gas rates should be corrected outside of a base rate proceeding to reflect the appropriate level of tax obligations following the Trump Administration's Tax Act, so too should the Company's rates reflect the correct tax rate adjusted under the Biden Administration. The Rider GMA would be the mechanism to enable that correction should it come to fruition. The Rider GMA would also remain active in the future for any other changes to state or federal income taxes, both increases and decreases, so that customers are always paying no more or no less than current tax rates.

Q. IS THE COMPANY PROPOSING TO INCLUDE CHANGES IN PROTECTED EDIT BALANCES IN RIDER GMA?

A. No.

Q. WHY NOT?

A. A public utility must compute the income tax component of its cost of service by following IRS tax normalization rules. To be compliant with the consistency requirements of tax normalization rules, book depreciation, tax expense, excess deferred income tax, and accumulated deferred income taxes should be treated consistently when calculating rates. Because the Company is not proposing to include changes to these other components in Rider GMA, the changes in protected EDIT cannot be included in Rider GMA either. Rather the Company will update protected EDIT balances at the time of its next natural gas base rate case.

IV. 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% 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% for both the base period and the forecast period.

Q. WHAT IS THE COMBINED FEDERAL AND STATE STATUTORY INCOME TAX RATE APPLICABLE DURING THE TEST PERIOD?

A. The combined statutory 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%. This rate includes the corporate statutory federal income tax rate of 21% and the composite statutory Kentucky corporate income tax rate of 5%. 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 Ms. Motsinger for her use in calculating the revenue requirement. I also provided him with the amount of income tax expense for the base period and the forecasted test period, based on these income tax rates.

V. <u>PROPERTY TAX EXPENSE</u>

Q. HOW DID DUKE ENERGY KENTUCKY CALCULATE THE PROPERTY TAX EXPENSE FOR THE FORECASTED TEST PERIOD?

A. We calculated the property tax expense based on the assessed value of Duke Energy Kentucky's property located in Kentucky with adjustments for anticipated property tax rate increases, additions, retirements and additional depreciation. As in past years, Duke Energy Kentucky will attempt to negotiate proper assessment values with the Kentucky Department of Revenue (KDR). The Company will notify the Commission of the result of its negotiations with the KDR for the 2021 tax year so the Commission can determine whether to adjust Duke Energy Kentucky's property tax expense for the forecasted test period.

VI. 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 Natural Gas Rates; 2) Approval of New Tariffs; and 3) All Other Required Approvals, Waivers, and Relief.	))))))	Case No. 2021-00190

DIRECT TESTIMONY OF

BENJAMIN WALTER BOHDAN PASSTY, PH.D.

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

June 1, 2021

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PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Benjamin Walter Bohdan Passty. My business address is 550 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 received a Bachelor of Arts degree in Economics and a Bachelor of Science Degree in Mathematics from Trinity University in 2002, a Master of Arts degree in Economics from Northwestern University in 2003, and a Doctor of Philosophy in Economics from Northwestern University in 2008.

I joined Duke Energy Corp. in July 2013 as a Lead Forecaster in the Load Forecasting Department. My current title is Lead Load Forecasting Analyst.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A. I am a dues-paying member of the Charlotte Economics Club, a local chapter of the National Association for Business Economists.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS LEAD FORECASTER IN THE LOAD FORECASTING GROUP.

A. My primary responsibility is to develop Duke Energy's long-term electric and gas forecasts for portions of its Midwest service area, currently Kentucky, Ohio and Indiana. These forecasts and analyses are provided to departments throughout Duke Energy and are used for budgeting, generation planning, and regulatory filings, such as long-term forecast reports, integrated resource plans, and rate cases. In addition to my primary duties, I regularly support special projects, requiring statistical analysis and forecasting, including assessment of current economic conditions.

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 presents and explains Duke Energy Kentucky's long-term energy and demand forecast prepared and utilized in the Company's rate case filing. This includes a discussion of the level of normal weather utilized in the preparation of the forecast. I sponsor Filing Requirement (FR) 16(7)(h)(5). I also discuss certain information that I supplied to Duke Energy Kentucky witnesses Ms. Abby L. Motsinger and Mr. Jeff L. Kern for their use in preparing additional testimony.

II. LOAD FORECAST

Q. DID YOU PREPARE THE COMPANY'S NATURAL GAS VOLUME FORECAST?

A. Yes, I did.

Q. HOW IS DUKE ENERGY KENTUCKY'S NATURAL GAS VOLUME FORECAST DEVELOPED?

A. Generally speaking, the Natural Gas Volume Forecast is developed in three steps: first, a service area economic forecast is obtained; second, a customer forecast is obtained; next, an energy forecast is prepared.

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' (a nationally recognized economic forecasting firm) portal *Economy.com* (Moody's). 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 a key 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. HOW IS THE CUSTOMER FORECAST OBTAINED?

A. A high-level customer growth forecast is delivered to me by Duke Energy's Natural Gas Sales and Delivery Segment that calculates the forecast. I calculate growth rates from this forecast, applying them to historical data to produce forecasts for a more detailed set of customer classes, as well as dividing between "full service" customers and "firm transportation" customers by "sharing them out" at percentages that are in-line with recent historical shares and growth rates.

Q. HOW IS THE ENERGY FORECAST DEVELOPED?

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

Q. WHAT ARE THE PRIMARY FACTORS AFFECTING NATURAL GAS USAGE?

A. The primary driver in all models is weather as measured via heating degree days. Some of the major economic drivers are the number of residential customers and economic activity measures detailed below. For the residential sector, the key factors are the population of the area, the average household income, and real energy prices. For the commercial sector, the key factors include total (non-farm) employment and real energy prices. The governmental sector model includes government employment, as well as energy prices. In the industrial sector—and a certain group of interruptible customers are modeled this way— the key factors include a weighted average of manufacturing employment and real manufacturing GDP and real energy prices.

Generally, energy use increases with higher economic activity. As energy prices increase, energy usage tends to decrease due to customers' conservation activities, although the relationship is not statistically significant for models of all classes of customers.

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

A. The forecasting models are exposed to historical data for these variables. Then, estimated coefficients are used along with projected data to calculate future energy consumption conditional on forecasts of these economic and weather conditions. 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.

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

A. The Company sometimes adjusts the forecast for anticipated increases in load due to a major new customer or a significant expansion at a current customer's site. The 2022 Test Year Load Forecast did include an adjustment for a large logistics facility located near the CVG airport. The natural gas volume delivered to this customer was added to the industrial class.

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

A. Yes, the econometric forecasting methodology used to create the Load Forecast is basically the same as that used by the Company in prior cases.

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

A. Yes, I am.

Q. ARE THE FACTORS THAT ARE USED BY DUKE ENERGY KENTUCKY IN FORMULATING ITS NATURAL GAS 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 of the utilities I am familiar with use the same factors considered by Duke Energy Kentucky, to varying degrees. Commonly used factors include: weather data, population, income, industrial production or output measures, employment, and price information. Price forecasts for alternate fuels including natural gas and fuel oil are often used as well. I am aware of survey data indicating that many large utilities utilize 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.

Q. PLEASE DESCRIBE ATTACHMENT BWP-1.

A. Attachment BWP-1 is a summary of Duke Energy Kentucky's natural gas sales forecast and five-year growth rates forecast. The projected annualized rate of growth in total retail sales for the five-year period 2022 to 2027 is 1.8% per year.

Q. HOW WOULD YOU CHARACTERIZE THE LONG-TERM TREND IN YOUR EXPECTATIONS FOR THAT GROWTH RATE IN RETAIL SALES?

A. The level of sales and the growth are higher than they would have been in earlier cycles of our forecast, which Duke Energy Kentucky refreshes annually. Three reasons for the higher results are: (1) volumes generally exceeding what was predicted in earlier forecast cycles; (2) an increase in the growth rate of expected customers; and, (3) the inclusion of volume that would be sold to a particular, large customer. The economic data that was supplied to us displayed fairly rapid growth in the short term, including rapid growth in the number of households in the service territory. Finally, the timing of the historical data used for this forecast meant that there was not a big impact of COVID-related shutdowns, as natural gas volumes are typically highest in January and February, meaning any decrease in usage for March and April would have had little impact on the modeling.

III. DEGREE DAY DATA USED IN THE FORECAST

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

A. Weather is expressed in terms of Heating Degree Days and Cooling Degree Days.

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

A. A Heating Degree Day (HDD) is calculated using a base temperature measured on the Fahrenheit scale and occurs when the daily average temperature is below the base (it is zero otherwise). 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 Cooling Degree Day (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. These generally do not affect the gas volumes forecasts.

Q. PLEASE EXPLAIN "NORMAL" WEATHER.

A. The natural gas forecast projects Duke Energy Kentucky's natural gas volume sales for the test period. In order to project this—since our econometric models include weather as an independent variable—one must make a judgment about the weather conditions expected to occur during the test period. This is known as "normal" weather. These expected weather conditions are forecast from historical weather data. This usage of an average of prior actual weather to predict what future weather patterns are likely to be experienced is an industry standard methodology.

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 30 years, and

NOAA updates its calculations for the United States for these 30-year periods at the end of each decade. The most current 30-year period used by NOAA is 1981-2010. NOAA's climate normal for the next 30-year normal weather period (1991-2020) has not yet been released as of this writing.

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

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

A. The years 1990-2019 were used to calculate normal weather. 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 natural gas volumes forecast is refreshed once annually, most recently during the second half of 2020.

Q. WHAT HAS BEEN THE LONG-TERM TREND IN HDD AND CDD FOR COVINGTON, KENTUCKY?

A. With respect to cooling, the years 1980-2020 appear to hint at a slight upward trend. There is a slight decreasing trend in heating degree days over the same period—also consistent with warmer temperatures—and these both are robust to statistical testing for a non-zero long-term trend. The graph in attachment BWP-2 shows these charts.

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

A. The years 2011-2020 are slightly warmer than the previous years in the sample. Statistical work suggests a warming trend during those years, although it cannot rule out that this trend emerges from random temperature variation. The data on winter heating degree days show a small decline upon visual inspection.

Q. HOW DO THE ACTUAL ANNUAL HEATING DEGREE DAYS FOR THE RECENT 10-YEAR NORMALS FOR COVINGTON, KENTUCKY, COMPARE TO 30-YEAR NORMALS?

A. See Attachment BWP-2 for a graph comparing the annual degree days in heating to the forecasts of the 30-year normal scheme, as well as the ten-year normal scheme and the NOAA static 30-year normal. The ten-year normal calls for slightly warmer winter weather than the thirty-year normal. Annual weather is much more variable than the degree to which the various normal projections vary from each other.

Q. DID YOU MEASURE HOW RELIABLE THE VARIOUS WEATHER NORMALS ARE?

A. Yes. One way to compare the relationship between the expected normal level of degree days to the actual number of degree days is to use a statistic known as the Mean Percent Error (MPE). MPE indicates whether the measure of normal degree days contains any bias to over-estimate or under-estimate the actual weather conditions. If MPE is positive, this indicates that there is a bias for the measure of normal to be higher than the actual. The formula to calculate MPE is the sum of

(Normal Degree Days minus Actual Degree Days) divided by Actual Degree Days. The sum is then divided by the number of observations. Mathematically:

$$\text{MPE} = \frac{1}{\text{N}}\sum_{t=1}^{N}\frac{\hat{Y}_t - Y_t}{Y_t}$$

Where $\hat{Y}$ = Normal Annual Degree Days

and Y = Actual Annual Degree Days

A difficulty with using this sum to compare the options for weather normalization is data availability: because so many years are required to compute the thirty-year weather normal, this statistic basically compares normal over a narrow sample space, implying a large standard error relative to any measurement difference. Because standard errors shrink for larger samples, the standard error of a 30-year forecast for normal weather should have a confidence interval that is 40 percent as large as the confidence interval around 10-year estimates. Because so many years are required for calculating the 30-year normal, it is really only possible to compare accuracy for years beginning with 2011 (which implies too small a sample for conclusive statistical testing). An informal comparison of the two forecasts for degree days shows slightly greater mean square error for the weather in years beginning with 2011 when using the 30-year normal instead of the 10-year normal.

IV. WEATHER NORMALIZATION ADJUSTMENT

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S WEATHER NORMALIZATION ADJUSTMENT MECHANISM.

A. The Weather Normalization Adjustment mechanism is intended to eliminate the impact of unexpected weather fluctuations on the volume of energy sold during the test period. It involves applying a calculation to change the volumetric sales based on the extent to which weather diverges from normal weather via parameters estimated separately for each class of customers. There are two parameters: a Base Load estimate (BL), and a sensitivity to heating degree days estimate, (HSF). The HSF represents the extent to which a change in heating degree days predicts a change in the volume of sales.

Q. PLEASE EXPLAIN YOUR CALCULATION OF THE BL and HSF FOR THE MECHANISM.

A. The most recent estimates were computed using 36 months of data (from January 2018 through December 2020) and are based on the meter read cycle. We estimate a linear model that predicts how volume sales billed to customers vary with weather conditions as measured through heating degree days and weighted to match the billing cycle for the time period of the sales. The factors that Mr. Kern presents were separately computed for each rate class.

The BL Factor equals the estimated intercept of this model, intuitively the volume of sales that can be expected in a month with negligible weather (as measured by heating degree days), while the HSF represents the weather coefficient, *i.e.* the degree to which a change in heating degree days predicts a change in the volume of sales. The standard errors of these coefficients were sufficiently low that all are statistically significant. The proposed values for BL and HSF are 1.047887 Mcf and 0.015467 Mcf/DD, respectively, for Rate RS. For Rate GS, they are 9.159645 Mcf and 0.096462 Mcf/DD, respectively. Mr. Kern also requested a "Correlation Factor"—commonly referred to as the "R-Squared" by statisticians—which gives the extent to which variation in sales is explained by these models, and all of these were quite high, above 0.95.

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 Ms. Motsinger with the gas Mcf sales for the forecasted portion of the base period, consisting of the twelve months ending August 31, 2021, and the forecasted test period, consisting of the twelve months ending December 31, 2022.

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

A. Yes.

VI. CONCLUSION

Q. WERE FR 16(7)(h)(5), THE INFORMATION YOU PROVIDED TO MS. MOTSINGER AND ATTACHMENTS BWP-1 THROUGH BWP-2 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

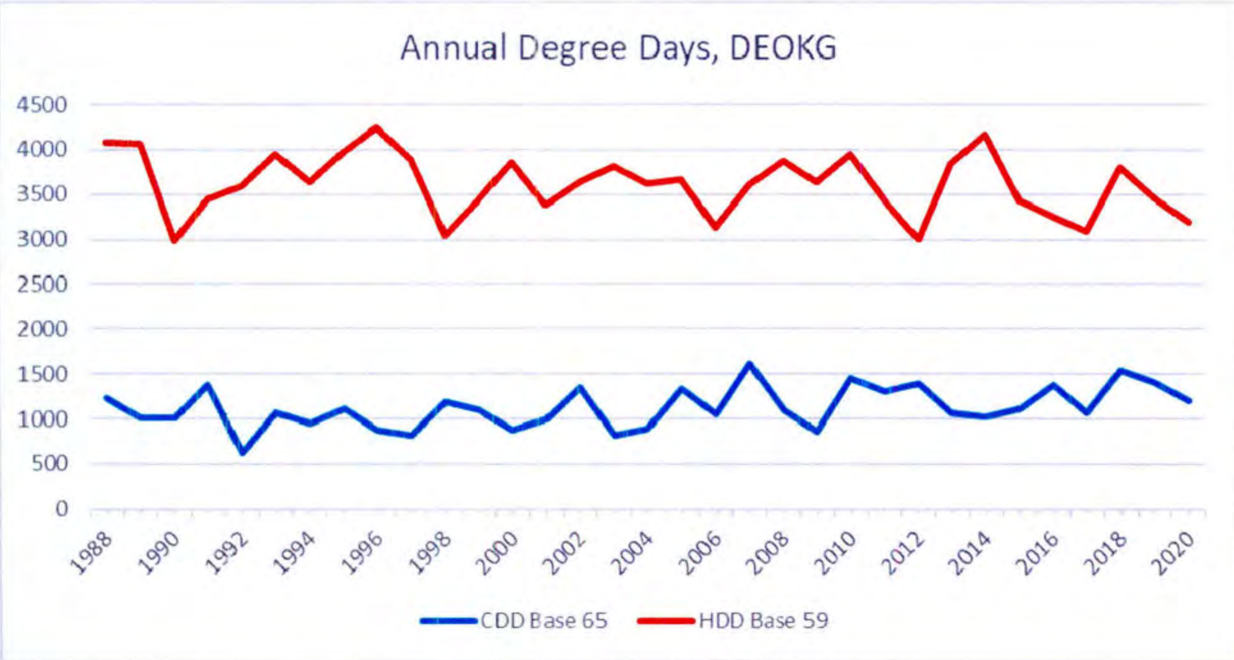
Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

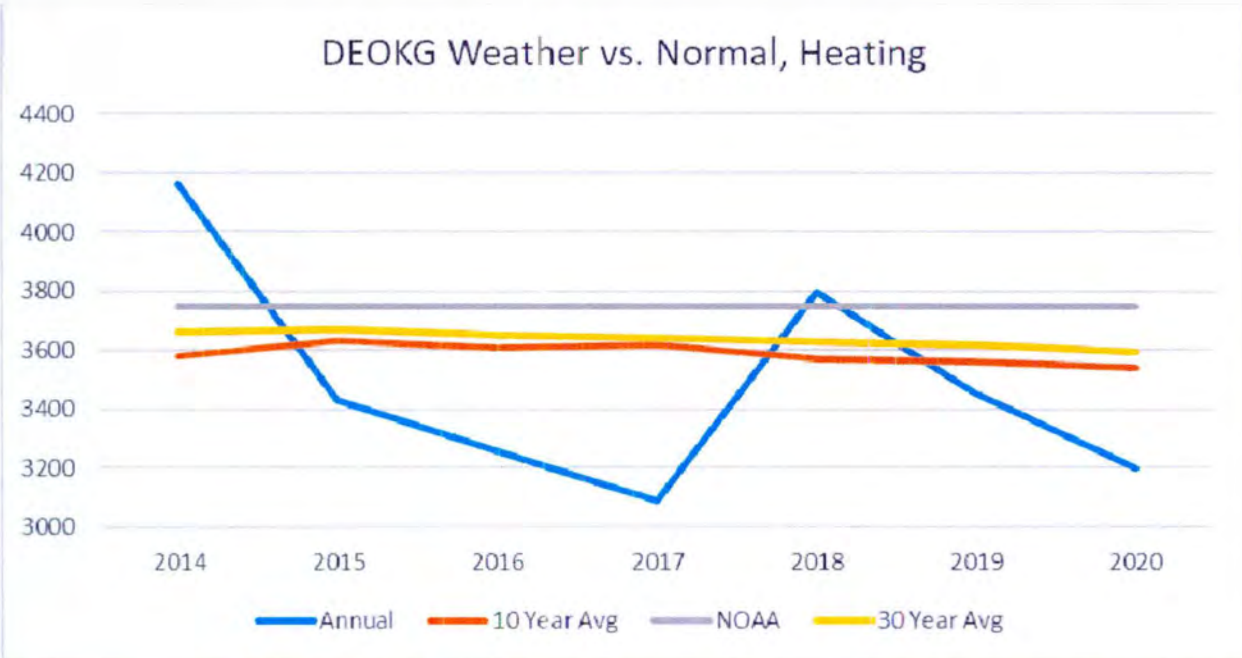
A. Yes.

DUKE ENERGY KENTUCKY
SERVICE AREA ENERGY FORECAST (Volume in MCF) (a)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)
								(1+2+3+4+5+6)
	YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET-HWY LIGHTING/ID/ OEU	OPA	OTHER	TOTAL CONSUMPTION
-5	2016	5,594,915	3,339,845	1,805,038	1,515,518	527,900		12,783,216
-4	2017	5,770,315	3,352,552	1,815,524	1,553,210	526,874		13,018,474
-3	2018	6,093,049	3,752,706	1,734,771	1,582,943	503,694		13,667,163
-2	2019	6,271,841	3,793,429	2,080,879	1,696,359	518,980		14,361,488
-1	2020	6,187,366	3,757,350	1,797,058	1,642,312	418,484		13,802,570
0	2021	6,228,383	3,462,668	2,110,718	1,639,727	517,794		13,959,291
1	2022	6,287,199	3,608,240	2,218,801	1,676,419	518,371		14,309,030
2	2023	6,367,716	3,737,054	2,478,825	1,710,045	518,697		14,812,337
3	2024	6,576,298	3,846,430	2,476,316	1,734,931	520,991		15,154,966
4	2025	6,720,598	3,893,018	2,447,126	1,753,892	519,762		15,334,395
5	2026	6,793,312	3,911,612	2,459,512	1,774,284	520,280		15,459,000
6	2027	6,898,203	3,934,874	2,465,605	1,795,418	520,775		15,614,876

(a) Figures in years -5 through -1 are weather-normalized history
(b) Figures in year 0 are forecast values


Annual Degree Days, DEOKG
4500
4000
3500
3000
2500
2000
1500
1000
500
0
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
CDD Base 65
HDD Base 59


DEOKG Weather vs. Normal, Heating
4400
4200
4000
3800
3600
3400
3200
3000
2014
2015
2016
2017
2018
2019
2020
Annual
10 Year Avg
NOAA
30 Year Avg

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Natural Gas Rates; 2) Approval of New Tariffs; and 3) All Other Required Approvals, Waivers, and Relief.	)))))	Case No. 2021-00190

DIRECT TESTIMONY OF

LESLEY G. QUICK

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

June 1, 2021

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PAGE

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lesley G. Quick, and my business address is 400 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 (Duke Energy Carolinas) as Vice President of Strategic Planning, Governance and Technology within Customer Services. Duke Energy Carolinas is a subsidiary of Duke Energy Corporation (Duke Energy) that provides various services to Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the 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 Financial Management from Clemson University in 2002. I started with Duke Energy two weeks after graduation and have remained an employee for the past 19 years. Since 2002, I have worked for the Company in a variety of roles, each with increasing responsibility, in Finance, Rates and Regulatory Compliance, Corporate Strategy, Customer Solutions products and services, and Revenue Services. I assumed my current position in Customer Services in 2020.

Q. PLEASE DESCRIBE YOUR DUTIES AS VICE PRESIDENT OF STRATEGIC PLANNING, GOVERNANCE, AND TECHNOLOGY.

A. My responsibilities include the oversight, leadership, integration and implementation of strategic business planning governance, change management, audit and compliance, technology support, and Consumer Affairs. I provide direction and leadership in the development of organizational business plans to ensure alignment and achievement of objectives, regulatory compliance and reporting, key performance indicators and operational metrics. Core to this role is strategic planning for the Company's Customer Services organization.

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

A. Yes. I have previously testified in Case No. 2019-00271 before the Kentucky Public Service Commission (Commission) and other regulatory commissions.

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

A. The purpose of my testimony is to highlight Duke Energy Kentucky's exceptional service to our customers and how that translates to customer satisfaction. I also describe some of the steps the Company is taking to further improve the experience and satisfaction of our customers when they engage with us. Finally, I support the Company's current late fee policy.

II. OVERVIEW OF CUSTOMER SERVICES

Q. PLEASE DESCRIBE THE COMPANY'S CUSTOMER SERVICE GOAL.

A. One of the Company's most important goals is to provide excellent customer service. Customer service is a factor in the policies, programs, and decisions that the Company implements.

Q. PLEASE BRIEFLY DESCRIBE HOW THE COMPANY MEASURES EXCELLENCE IN CUSTOMER SERVICE.

A. As discussed by Witness Spiller, the Company has implemented a comprehensive ecosystem of tools to gain insights into customers' pain points, allowing the Company to monitor, adjust, and continue improving the customer experience. The Company's proprietary relationship study, CX Monitor, surveys customers to measure advocacy and satisfaction. It measures customer satisfaction with key experiences they have had with Duke Energy Kentucky over the past 12 months, and asks for prompt customer feedback, which is reviewable by the Company in near real-time. Examples of these experiences may be a payment experience or reporting a safety concern. Customers provide a score for each experience they have had on a '0-10' scale and are able to provide open-ended verbatim comments detailing the primary reason(s) for their score. The value of the CX Monitor over other surveys is that it asks our own customers about their perceptions, which can be compared against their actual experiences. Duke Energy Kentucky has been able to leverage the data to generate insights, which has helped it prioritize investment to drive customer satisfaction. The Company has also implemented Fastrack 2.0, a proprietary post-transaction measurement program. Fastrack 2.0 measures the quality of interactions customers have with the Company, helping the evaluation of its customer performance.

The results of the Company reacting to these customer insights are reflected in the latest J.D. Power Natural Gas Utility Residential Customer Satisfaction Study, showing a continued trend of improving scores.

Q. HOW CAN A CUSTOMER RAISE A COMPLAINT?

A. The Company's customers have numerous avenues to voice complaints. As I previously mentioned, CX Monitor and Fastrack are two key proprietary surveys utilized by the Company on an ongoing basis to track customer feedback. At the end of each survey, customers have the opportunity to provide additional comments regarding any outstanding question(s) they have that still need to be answered or issue(s) they have with the Company that still need to be resolved. These comments turn into high priority Hot Alerts which are forwarded to the Consumer Affairs team to resolve. A member of the Company's customer service staff directly contacts the customer to ensure satisfactory resolution of their question or issue. Separately, a Hot Alert may be triggered by an automated key word software review of survey verbatims which may indicate customer frustration or a poor experience, even if the customer did not directly ask for follow up.

In addition, the "I Can Help" system allows customers to raise issues and inquiries directly with Company employees. This tool allows employees to immediately begin the process of resolving a problem, as well as track resolution of these issues.

Overall, the Company provides an array of options for customers to report issues, and the Company's history reflects seriousness in addressing complaints and inquiries, either formal or informal. Duke Energy Kentucky is steadfast in its efforts to improve and maintain a high level of customer service. Recently, however, the Company has focused on being proactive rather than reactive. In 2019, the Company created the Customer Resolution Tool, a web-based application built to prevent escalations and complaints. The tool is utilized by Senior Customer Care Specialists, team leads and supervisors in Customer Care Operations to create cases when work order timeframes have not been met or customers have had to make repeat calls. The focus is on work orders related to field work, engineering, gas emergencies, and repairs. The goal is to identify and resolve customer issues before the customer feels compelled to escalate their concern by lodging a complaint.

Thus, while the Company continues to seek feedback from customers through various survey instruments, Duke Energy Kentucky is also making it easier for them to do so and driving improvements to follow-up and close the loop. But most importantly, the Company is using innovative tools to reduce complaints and the need for customers to ever escalate an issue.

Q. HOW DOES THE COMPANY UTILIZE CUSTOMER CARE CENTERS, ITS CALL CENTER OPERATION?

A. Duke Energy Kentucky has the ability to utilize two Customer Care Centers in the Midwest to support our Duke Energy Kentucky utility operations and serve our customers. These two Midwest customer care centers are located at 139 East Fourth Street, Cincinnati, Ohio, and at 1000 East Main Street, Plainfield, Indiana, respectively. Customer Care specialists are available from 7:00 a.m. to 7:00 p.m. Monday through Friday for normal business. Additionally, during the COVID-19 pandemic, most Customer Care specialists transitioned to a remote working environment to continue serving customers safely. Finally, we also utilize vendor call centers in Alabama, North Carolina, and West Virginia to supplement our Midwest customer care centers.

Additionally, Duke Energy maintains its Social Media Customer Care program, which operates Monday through Friday from 8:00 a.m. to 5:00 p.m. assisting customers on the Duke Energy enterprise social media channels which consist of Facebook, Twitter, LinkedIn, and Instagram. Utilizing resources from the Consumer Affairs organization, employees assist customers in a private, one-on-one conversation using Messenger to address any questions or issues that they may be having. The frequent inquiries received on social media are related to billing, payment and website.

Q. PLEASE DESCRIBE HOW DUKE ENERGY KENTUCKY'S SOCIAL MEDIA PROGRAM HAS EVOLVED TO KEEP PACE WITH CUSTOMERS' CHANGING EXPECTATIONS.

A. Duke Energy Kentucky customers utilize the Duke Energy enterprise social channels to contact the Company for account-related and service inquiries. The social media channels continue to grow and as of May 2021, more than 630,000 followers on its Facebook, Twitter, Instagram, and LinkedIn pages. Using social media allows the Company to proactively post warning and safety information to quickly reach as many customers and stakeholders as possible, engage with customers who have safety-related or account questions, and monitor how messages are being received and responded to.

Q. HOW HAS DUKE ENERGY KENTUCKY MODERNIZED ITS COMMUNICATION CAPABILITIES FOR CUSTOMERS?

A. The Company has made available a free mobile app for customers to utilize for managing their account. The mobile app allows residential and small business customers to easily manage their account from anywhere in the U.S. The app was developed based on customers' most requested features – with it, customers can: view and pay their bill, use the app to set reminders, schedule automatic payments or view their billing history, monitor their energy use over time so they can better manage it, and receive personalized offers that help them save. The app uses the same log-in as a customer's current account and has an option to use fingerprint or facial recognition for a fast, secure sign-in. The app gives customers a seamless way to manage their account, however as a safety precaution, customers experiencing a gas outage, smelling natural gas, or suspecting a leak are always directed to call the Company or call 911 in an emergency.

III. <u>TRANSFORMING THE CUSTOMER EXPERIENCE</u>

Q. PLEASE DESCRIBE THE COMPANY'S EFFORTS TO ENHANCE CUSTOMER SATISFACTION.

A. Duke Energy Kentucky is working hard across the business to further improve the customer experience. In the Customer Services organization, we are doing our part to transform the customer experience by making strategic, value-based investments for the benefit of our customers.

Q. PLEASE PROVIDE EXAMPLES OF WAYS YOUR ORGANIZATION IS HELPING TO TRANSFORM THE CUSTOMER EXPERIENCE.

A. Two key examples are enhancements to our interactive voice response (IVR) system and the future deployment of a new customer information system (CIS) called Customer Connect.

Q. PLEASE DESCRIBE THE IVR SYSTEM.

A. Duke Energy launched an effort to replace the existing IVR system across all jurisdictions with advanced technology focused on transforming the caller's experience. The IVR design reflects learnings from customer feedback and industry best practices that led to several key areas of focus, which include: 1) proactively identifying the customers and why they are calling the Company; 2) a tailored customer experience similar to what they receive from other consumer product companies; and 3) less menu options to complete their request in the IVR. Options available after the deployment of the new IVR include call intent prediction, easy self-serve options, customer call back, and a post-call survey. The call intent prediction functionality predicts the reason the customer is calling the Company. For example, "I see you have a pending service order scheduled for tomorrow. Is this why you are calling?" The Company recognizes customers want the ability to self-serve while navigating seamlessly through the IVR. The self-service functionality, such as requesting a payment arrangement, has been improved supporting a positive customer experience. New self-serve options include allowing customers the ability to update their phone number and requesting their account number through the IVR.

An increased number of calls during a specific timeframe may result in longer than usual hold times to speak with a specialist. The new IVR provides customers the option to continue holding until a specialist is available or have their place in line reserved allowing us to return their call at the phone number of their choice. The Company's ongoing focus to understand "the voice of the customer" has been expanded to the new IVR with the implementation of the post-call survey. The post-call survey offers customers the option to provide feedback on their experience.

Q. PLEASE DESCRIBE THE NEW CIS.

A. Duke Energy Kentucky witness Retha Hunsicker provides greater detail regarding the legacy CIS and the new CIS in her direct testimony. In summary, Duke Energy has begun conversion of its antiquated and incompatible customer information systems into a single and modern customer service platform, known as Customer Connect. Through this conversion, the Company will be able to deliver a customer experience that will simplify, strengthen, and advance our ability to serve our customers. The platform will be leveraged to provide real-time insights to enhance the customer experience.

IV. <u>LATE PAYMENT FEE POLICY</u>

Q. PLEASE EXPLAIN THE COMPANY'S CURRENT LATE-PAYMENT FEE POLICY.

A. Duke Energy Kentucky's late-payment fee policy encourages timely customer payments to assist in managing the overall financial burden on all customers that occurs from bad debt and collection costs as well as serving an important role in the bill collection strategy.[1] The late-payment fee policy is enacted when a customer payment is not received within twenty-one (21) days from the date the bill is mailed by the Company. If not paid before close of business on day twenty-one (21), the

[1] *In the Matter of Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company*, Case No. 1990-00158, Order at 72-74 (Ky. PSC Dec. 21, 1990).

monthly bill plus 5%, is due and payable to the Company as outlined in the Company's tariffs.[2]

Q. ARE LATE PAYMENT FEES COMMON BUSINESS PRACTICE?

A. Yes. Duke Energy Kentucky is not unique in assessing a late-payment fee. In fact, it is common practice across not only many natural gas and other regulated utilities but most commercial industries as well as local, state, and federal government entities impose a late fee for untimely payments.

Q. WHY IS IT IMPORTANT FOR CUSTOMERS TO PAY TIMELY?

A Customers who pay on time are less expensive to serve, which is a benefit to all customers. On-time payments help avoid incremental costs related to bill collection, bad debt, and disconnections of service. Timely payment is critical to managing carrying costs and cash flow associated with providing natural gas service. Overall, on-time payments are a benefit to all customers.

Q. HOW DO LATE-PAYMENT FEES HELP REDUCE COSTS FOR OTHER CUSTOMERS?

A. Collected late-payment fees reduce the expense shared by all customers stemming from the additional costs associated with customers' untimely payments or unpaid bills. Only customers whose payment has not been received by their due date are assessed the fee. The collection of the late payment fee assists in reducing the

[2] *See e.g.*, KY. P.S.C. Gas No. 2, Two-Hundred -Sixth Revised Sheet No. 30.

incremental delinquency-related costs included in the cost of service, such as collections, bad debt, or disconnections.

Q. WHAT IS THE AMOUNT OF REVENUE REFLECTED IN THE TEST YEAR ASSOCIATED WITH THE LATE-PAYMENT FEES?

A. Late-payment fees are treated as a reduction to the overall uncollectible expense. The late-payment fees reflected in the revenue requirement of this proceeding reduce the overall uncollectible expense by $369,396 as shown on workpaper WPD-2.15 to Schedule D-2.15 and discussed in more detail by Company witness Jay P. Brown.

V. CONCLUSION

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

A. Yes.