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. 2018-00261

FILING REQUIREMENTS

VOLUME 15

Duke Energy Kentucky, Inc.
Case No. 2018-00261
Forecasted Test Period Filing Requirements
Table of Contents

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.	Robert H. "Beau" Pratt Michael Covington
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 William Don Wathen, Jr.
1	9	807 KAR 5:001 Section 16 (1)(b)(2)	Certified copy of certificate of assumed name required by KRS 365.015 or statement that certificate not necessary.	Amy B. Spiller
1	10	807 KAR 5:001 Section 16 (1)(b)(3)	New or revised tariff sheets, if applicable in a format that complies with 807 KAR 5:011 with an effective date not less than thirty (30) days from the date the application is filed	Bruce L. Sailers
1	11	807 KAR 5:001 Section 16 (1)(b)(4)	Proposed tariff changes shown by present and proposed tariffs in comparative form or by indicating additions in italics or by underscoring and striking over deletions in current tariff.	Bruce L. Sailers
1	12	807 KAR 5:001 Section 16 (1)(b)(5)	A statement that notice has been given in compliance with Section 17 of this administrative regulation with a copy of the notice.	Amy B. Spiller
1	13	807 KAR 5:001 Section 16(2)	If gross annual revenues exceed $5,000,000, written notice of intent filed at least 30 days, but not more than 60 days prior to application. Notice shall state whether application will be supported by historical or fully forecasted test period.	Amy B. Spiller
1	14	807 KAR 5:001 Section 16(3)	Notice given pursuant to Section 17 of this administrative regulation shall satisfy the requirements of 807 KAR 5:051, Section 2.	Amy B. Spiller
1	15	807 KAR 5:001 Section 16(6)(a)	The financial data for the forecasted period shall be presented in the form of pro forma adjustments to the base period.	Robert H. "Beau" Pratt
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.	Sarah E. Lawler Cynthia S. Lee Robert H. "Beau" Pratt
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.	Sarah E. Lawler
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.	Robert H. "Beau" Pratt

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.	Robert H. "Beau" Pratt
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.	Sarah E. Lawler
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.	Robert H. "Beau" Pratt Gary J. Hebbeler
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.	Robert H. "Beau" Pratt
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.	Robert H. "Beau" Pratt
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.	Robert H. "Beau" Pratt Gary J. Hebbeler
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.	Robert H. "Beau" Pratt Gary J. Hebbeler

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.	Robert H. "Beau" Pratt Gary J. Hebbeler Benjamin Passty
1	29	807 KAR 5:001 Section 16(7)(i)	Most recent FERC or FCC audit reports.	Michael Covington
1	30	807 KAR 5:001 Section 16(7)(j)	Prospectuses of most recent stock or bond offerings.	Robert H. "Beau" Pratt
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).	Michael Covington
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.	Robert H. "Beau" Pratt
3	33	807 KAR 5:001 Section 16(7)(m)	Current chart of accounts if more detailed than Uniform System of Accounts charts.	Michael Covington
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.	Michael Covington
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.	Michael Covington Robert H. "Beau" Pratt
3-11	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.	Michael Covington
11	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.	Michael Covington
11	38	807 KAR 5:001 Section 16(7)(r)	Quarterly reports to the stockholders for the most recent 5 quarters.	Robert H. "Beau" Pratt

11	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
11	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	Sarah E. Lawler
11	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
11	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
11	43	807 KAR 5:001 Section 16(7)(w)	Local exchange carriers with fewer than 50,000 access lines need not file cost of service studies, except as specifically directed by PSC. Local exchange carriers with more than 50,000 access lines shall file: 1. Jurisdictional separations study consistent with Part 36 of the FCC's rules and regulations; and 2. Service specific cost studies supporting pricing of services generating annual revenue greater than $1,000,000 except local exchange access: a. Based on current and reliable data from single time period; and b. Using generally recognized fully allocated, embedded, or incremental cost principles.	N/A
11	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.	Sarah E. Lawler

11	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.	Sarah E. Lawler Cynthia S. Lee Robert H. "Beau" Pratt John R. Panizza James E. Ziolkowski Michael Covington
11	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.	Sarah E. Lawler
11	.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.	Sarah E. Lawler Cynthia S. Lee Robert H. "Beau" Pratt James E. Ziolkowski
11	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
11	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.	Sarah E. Lawler
11	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.	Sarah E. Lawler Renee H. Metzler
11	51	807 KAR 5:001 Section 16(8)(h)	Computation of gross revenue conversion factor for forecasted period.	Sarah E. Lawler
11	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.	Michael Covington Robert H. "Beau" Pratt
11	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.	Robert H. "Beau" Pratt
11	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.	Cynthia S. Lee Robert H. "Beau" Pratt Michael Covington
11	55	807 KAR 5:001 Section 16(8)(l)	Narrative description and explanation of all proposed tariff changes.	Bruce L. Sailers
11	56	807 KAR 5:001 Section 16(8)(m)	Revenue summary for both base and forecasted periods with supporting schedules which provide detailed billing analyses for all customer classes.	Bruce L. Sailers
11	57	807 KAR 5:001 Section 16(8)(n)	Typical bill comparison under present and proposed rates for all customer classes.	Bruce L. Sailers
11	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.	William Don Wathen, Jr.

11	59	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
11	60	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

11	61	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

11	62	807 KAR 5:001 Section 17(4)	(4) Notice Content. Each notice issued in accordance with this section shall contain: (a) The proposed effective date and the date the proposed rates are expected to be filed with the commission; (b) The present rates and proposed rates for each customer classification to which the proposed rates will apply; (c) The amount of the change requested in both dollar amounts and percentage change for each customer classification to which the proposed rates will apply; (d) The amount of the average usage and the effect upon the average bill for each customer classification to which the proposed rates will apply, except for local exchange companies, which shall include the effect upon the average bill for each customer classification for the proposed rate change in basic local service; (e) A statement that a person may examine this application at the offices of (utility name) located at (utility address); (f) A statement that a person may examine this application at the commission's offices located at 211 Sower Boulevard, Frankfort, Kentucky, Monday through Friday, 8:00 a.m. to 4:30 p.m., or through the commission's Web site at http://psc.ky.gov; (g) A statement that comments regarding the application may be submitted to the Public Service Commission through its Web site or by mail to Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602; (h) A statement that the rates contained in this notice are the rates proposed by (utility name) but that the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice; (i) A statement that a person may submit a timely written request for intervention to the Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602, establishing the grounds for the request including the status and interest of the party; and (j) A statement that if the commission does not receive a written request for intervention within thirty (30) days of initial publication or mailing of the notice, the commission may take final action on the application.	Bruce L. Sailers
11	63	807 KAR 5:001 Section 17(5)	(5) Abbreviated form of notice. Upon written request, the commission may grant a utility permission to use an abbreviated form of published notice of the proposed rates, provided the notice includes a coupon that may be used to obtain all the required information.	N/A

12	-	807 KAR 5:001 Section 16(8)(a) through (n)	Schedule Book, including Work Papers (Schedules A-N)	Various
13	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 1 of 3)	Various
14	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 2 of 3)	Various
15	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 3 of 3)	Various
16-17	-	KRS 278.2205(6)	Cost Allocation Manual	Legal

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 a Decoupling Mechanism; 3) Approval of New Tariffs; and 4) All Other Required Approvals, Waivers, and Relief.	)))))))	Case No. 2018-00261

DIRECT TESTIMONY OF

ROGER A. MORIN, PhD

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

August 31, 2018

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND SUMMARY OF RECOMMENDATION 1

II. REGULATORY FRAMEWORK AND RATE OF RETURN 8

III. COST OF EQUITY CAPITAL ESTIMATES 15

- **A. DCF Estimates 17**
- **B. CAPM Estimates 32**
- **C. Historical Risk Premium Estimates 50**
- **D. Allowed Risk Premium Estimates 51**
- **E. Need for Flotation Cost Adjustment 54**

IV. CONCLUSION 60

Attachments:

RAM-1 Resume of Roger A. Morin

RAM-2 Value Line's Natural Gas Distribution Group

RAM-3 Natural Gas Distribution Utilities DCF Analysis Value Line Growth Rates

RAM-4 Natural Gas Distribution Utilities DCF Analysis Analysts' Growth Forecasts

RAM-5 Investment-Grade Dividend-Paying Combination Gas & Electric Utilities Covered in Value Line's Electric Utility Industry Group

RAM-6 Second Proxy Group for Duke Energy Kentucky, Inc.

RAM-7 Combination Gas & Electric Utilities DCF Analysis Value Line Growth Rates

RAM-8 Combination Gas & Electric Utilities DCF Analysis Analysts' Growth Forecasts

RAM-9 Natural Gas Utilities Beta Estimates

RAM-10 2018 Utility Industry Historical Risk Premium

RAM-11 Equity Risk Premium – Treasury Bond

APPENDICES

Appendix A CAPM, Empirical CAPM

Appendix B Flotation Cost Allowance

I. INTRODUCTION AND SUMMARY OF RECOMMENDATION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Dr. Roger A. Morin. My business address is Georgia State University, Robinson College of Business, University Plaza, Atlanta, Georgia, 30303. I am Emeritus Professor of Finance at the Robinson College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. I am also a principal in Utility Research International, an enterprise engaged in regulatory finance and economics consulting to business and government. I am testifying on behalf of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company).

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Bachelor of Engineering degree and an MBA in Finance from McGill University, Montreal, Canada. I received my Ph.D. in Finance and Econometrics at the Wharton School of Finance, University of Pennsylvania.

Q. PLEASE SUMMARIZE YOUR ACADEMIC AND BUSINESS CAREER.

A. I have taught at the Wharton School of Finance, University of Pennsylvania, Amos Tuck School of Business at Dartmouth College, Drexel University, University of Montreal, McGill University, and Georgia State University. I was a faculty member of Advanced Management Research International, and I am currently a faculty member of S&P Global Intelligence (formerly SNL Knowledge Center or SNL), where I continue to conduct frequent national executive-level education seminars throughout the United States. In the last 30 years, I have conducted numerous national seminars on "Utility Finance," "Utility Cost of Capital," "Alternative Regulatory Frameworks," and "Utility Capital Allocation," which I have developed on behalf of S&P Global Intelligence and its predecessors.

I have authored or co-authored several books, monographs, and articles in academic scientific journals on the subject of finance. They have appeared in a variety of journals, including The Journal of Finance, The Journal of Business Administration, International Management Review, and Public Utilities Fortnightly. I published a widely-used treatise on regulatory finance, Utilities' Cost of Capital, Public Utilities Reports, Inc., Arlington, Va. 1984. In late 1994, the same publisher released my book, Regulatory Finance, a treatise on the application of finance to regulated utilities. A revised and expanded edition of this book, The New Regulatory Finance, was published in 2006. I have been engaged in extensive consulting activities on behalf of numerous corporations, law firms, and regulatory bodies in matters of financial management and corporate litigation.

Please see Attachment RAM-1 for my professional qualifications.

Q. HAVE YOU PREVIOUSLY TESTIFIED ON COST OF CAPITAL BEFORE UTILITY REGULATORY BODIES?

A. Yes, I have been a cost of capital witness before nearly 50 regulatory bodies in North America, including the Kentucky Public Service Commission (the Commission) and the Federal Energy Regulatory Commission. I have testified before the following state, provincial, and other local regulatory commissions:

Alabama	Florida	Missouri	Ontario
Alaska	Georgia	Montana	Oregon
Alberta	Hawaii	Nebraska	Pennsylvania
Arizona	Illinois	Nevada	Quebec
Arkansas	Indiana	New Brunswick	South Carolina
British Columbia	Iowa	New Hampshire	South Dakota
California	Kentucky	New Jersey	Tennessee
City of New Orleans	Louisiana	New Mexico	Texas
Colorado	Maine	New York	Utah
CRTC	Manitoba	Newfoundland	Vermont
Delaware	Maryland	North Carolina	Virginia
District of Columbia	Michigan	North Dakota	West Virginia
FCC	Minnesota	Nova Scotia	Wisconsin
FERC	Mississippi	Oklahoma	

The details of my participation in regulatory proceedings are also provided in Attachment RAM-1.

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

A. The purpose of my testimony in this proceeding is to present an independent appraisal of the fair and reasonable rate of return on equity (ROE) on the common equity capital invested in Duke Energy Kentucky's natural gas distribution operations in the State of Kentucky. Based upon this appraisal, I have formed my professional judgment as to a return on such capital that would:

(1) be fair to ratepayers;

(2) allow Duke Energy Kentucky to attract the capital needed for infrastructure and reliability investments on reasonable terms;

(3) maintain Duke Energy Kentucky's financial integrity; and

(4) be comparable to returns offered on comparable risk investments.

Q. PLEASE BRIEFLY IDENTIFY THE ATTACHMENTS AND APPENDICES ACCOMPANYING YOUR TESTIMONY.

A. I have attached to my testimony Attachment RAM-1 through Attachment RAM-11, and Appendices A and B. These attachments and appendices relate directly to points in my testimony, and are described in further detail in connection with the discussion of those points in my testimony.

Q. PLEASE SUMMARIZE YOUR FINDINGS CONCERNING DUKE ENERGY KENTUCKY'S COST OF COMMON EQUITY.

A. It is my opinion that a fair, reasonable and sufficient ROE for Duke Energy Kentucky is 9.9%, assuming the Commission adopts Duke Energy Kentucky's weather adjustment clause. If the Company's proposed weather adjustment clause is not approved however, it is my opinion that a fair, reasonable, and sufficient ROE for Duke Energy Kentucky lies in the upper half of a ROE range of 9.9% - 10.6%.

My recommended ROE is required in order for the Company to: (i) attract capital on reasonable terms, (ii) maintain its financial integrity, and (iii) earn a return commensurate with returns on comparable risk investments.

My ROE recommendation is derived from cost of capital studies that I performed using the financial models available to me and from the application of my professional judgment to the results. I applied various cost of capital methodologies, including the Discounted Cash Flow (DCF), Risk Premium, and

Capital Asset Pricing Model (CAPM), to two surrogates for Duke Energy Kentucky. They are: a group of investment-grade natural gas distribution utilities covered in Value Line's Natural Gas Distribution Group and a group of investment-grade combination gas and electric utilities covered in Value Line's Electric Utility Composite. I have also surveyed and analyzed the historical risk premiums in the utility industry and risk premiums allowed by regulators as indicators of the appropriate risk premium for the natural gas utility industry.

My recommended rate of return reflects the application of my professional judgment to the results in light of the indicated returns from my Risk Premium, CAPM, and DCF analyses.

Q. WOULD IT BE IN THE BEST INTERESTS OF RATEPAYERS FOR THE COMMISSION TO APPROVE A ROE IN THE RANGE OF 9.9% - 10.6% FOR DUKE ENERGY KENTUCKY'S NATURAL GAS UTILITY OPERATIONS?

A. Yes. My analysis shows that this range fairly compensates investors, maintains Duke Energy Kentucky's credit strength, and attracts the capital needed for utility infrastructure and reliability capital investments. Adopting a lower ROE would ultimately increase costs for ratepayers.

Q. PLEASE EXPLAIN HOW TOO-LOW ALLOWED ROES CAN ULTIMATELY INCREASE COSTS FOR CUSTOMERS.

A. If a utility is authorized a ROE below the level required by equity investors, the utility or its parent will find it difficult to access equity capital. Investors will not provide equity capital at the current market price if the earnable return on equity is below the level they require given the risks of an equity investment in the utility. The equity market corrects this by generating a stock price in equilibrium that reflects the valuation of the potential earnings stream from an equity investment at the risk-adjusted return equity investors require. In the case of a utility that has been authorized a return below the level investors believe is appropriate for the risk they assume, the result is a decrease in the utility's (or its parent) stock price. This reduces the financial viability of equity financing in two ways. First, because the utility's price per share of common stock decreases, the net proceeds from issuing common stock are reduced. Second, since the utility's market to book ratio decreases with the decrease in the share price of common stock, the potential risk from dilution of equity investments reduces investors' inclination to purchase new issues of common stock. The ultimate effect is the utility will rely more on debt financing to meet its capital needs.

As a company relies more on debt financing, its capital structure becomes more leveraged. Because debt payments are a fixed financial obligation to the utility, and income available to common equity is subordinate to fixed charges, this decreases the operating income available for dividend and earnings growth. Consequently, equity investors face greater uncertainty about future dividends and earnings from the company. As a result, the company's equity becomes a riskier investment. The risk of default on a company's bonds also increases, making the utility's debt a riskier investment. This increases the cost to the utility from both debt and equity financing and increases the possibility a company will not have access to the capital markets for its outside financing needs. Ultimately, to ensure that Duke Energy Kentucky has access to capital markets for its capital needs, a fair and reasonable authorized ROE of 9.9% is required.

Duke Energy Kentucky must secure outside funds from capital markets to finance required utility plant and equipment investments irrespective of capital market conditions, interest rate conditions and the quality consciousness of market participants. Thus, rate relief requirements and supportive regulatory treatment, including approval of my recommended ROE, are essential.

Q. PLEASE DESCRIBE HOW THE REMAINDER OF YOUR TESTIMONY IS ORGANIZED.

A. The remainder of my testimony is divided into three broad sections:

(i) Regulatory Framework and Rate of Return;

(ii) Cost of Equity Estimates;

(iii) Summary and Recommendation;

The first section discusses the rudiments of rate of return regulation and the basic notions underlying rate of return. The second section contains the application of DCF, Risk Premium, and CAPM tests. In the third section, the results from the various approaches used in determining a fair return are summarized.

II. REGULATORY FRAMEWORK AND RATE OF RETURN

Q. PLEASE EXPLAIN HOW A REGULATED COMPANY'S RATES SHOULD BE SET UNDER TRADITIONAL COST OF SERVICE REGULATION.

A. Under the traditional regulatory process, a regulated company's rates should be set so that the company recovers its costs, including taxes and depreciation, plus a fair and reasonable return on its invested capital. The allowed rate of return must necessarily reflect the cost of the funds obtained, that is, investors' return requirements. In determining a company's required rate of return, the starting point is investors' return requirements in financial markets. A rate of return can then be set at a level sufficient to enable a company to earn a return commensurate with the cost of those funds.

Funds can be obtained in two general forms, debt capital and equity capital. The cost of debt funds can be easily ascertained from an examination of the contractual interest payments. The cost of common equity funds (*i.e.*, investors' required rate of return) is more difficult to estimate. It is the purpose of the next section of my testimony to estimate fair and reasonable ROE ranges for Duke Energy Kentucky's cost of common equity capital.

Q. WHAT FUNDAMENTAL PRINCIPLES UNDERLIE THE DETERMINATION OF A FAIR AND REASONABLE ROE?

A. The heart of utility regulation is the setting of just and reasonable rates by way of a fair and reasonable return. There are two landmark United States Supreme Court cases that define the legal principles underlying the regulation of a public utility's rate of return and provide the foundations for the notion of a fair return:

1. *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923); and

2. *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

The *Bluefield* case set the standard against which just and reasonable rates of return are measured:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties ... The return should be reasonable, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties.

Bluefield Water Works & Improvement Co., 262 U.S. at 692 (emphasis added).

The *Hope* case expanded on the guidelines to be used to assess the reasonableness of the allowed return. The Court reemphasized its statements in the *Bluefield* case and recognized that revenues must cover "capital costs." The Court stated:

> *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 ... 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 attract capital.*

Hope Natural Gas Co., 320 U.S. at 603 (emphasis added).

The United States Supreme Court reiterated the criteria set forth in *Hope* in *Federal Power Commission v. Memphis Light, Gas & Water Division*, 411 U.S. 458 (1973); in *Permian Basin Rate Cases*, 390 U.S. 747 (1968); and, most recently, in *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989). In the *Permian Basin Rate Cases*, the Supreme Court stressed that a regulatory agency's rate of return order should:

> *reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed.*

Permian Basin Rate Cases, 390 U.S. at 792.

Therefore, the "end result" of this Commission's decision should be to allow Duke Energy Kentucky the opportunity to earn a return on equity that is:

> (i) commensurate with returns on investments in other firms having corresponding risks;
>
> (ii) sufficient to assure confidence in Duke Energy Kentucky's financial integrity; and
>
> (iii) sufficient to maintain Duke Energy Kentucky's creditworthiness and ability to attract capital on reasonable terms.

Q. HOW IS THE FAIR RATE OF RETURN DETERMINED?

A. The aggregate return required by investors is called the "cost of capital." The cost of capital is the opportunity cost, expressed in percentage terms, of the total pool of capital employed by the utility. It is the composite weighted cost of the various classes of capital (*e.g.*, bonds, preferred stock, common stock) used by the utility, with the weights reflecting the proportions of the total capital that each class of capital represents. The fair return in dollars is obtained by multiplying the rate of return set by the regulator by the utility's "rate base." The rate base is essentially the net book value of the utility's plant and other assets used to provide utility service in a particular jurisdiction.

Utilities like Duke Energy Kentucky must compete with everyone else in the free market for the input factors of production, whether labor, materials, machines, or capital, including the capital investments required to support the utility infrastructure. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices that are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities and other investor-owned businesses must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require (*e.g.*, the interest on debt capital or the expected return on equity). In order to attract the necessary capital, utilities must compete with alternative uses of capital and offer a return commensurate with the associated risks.

Q. HOW DOES THE CONCEPT OF A FAIR RETURN RELATE TO THE CONCEPT OF OPPORTUNITY COST?

A. The concept of a fair return is intimately related to the economic concept of "opportunity cost." When investors supply funds to a utility by buying its stocks or bonds, they are not only postponing consumption, giving up the alternative of spending their dollars in some other way, they are also exposing their funds to risk and forgoing returns from investing their money in alternative comparable risk investments. The compensation they require is the price of capital. If there are differences in the risk of the investments, competition among firms for a limited supply of capital will bring different prices. The capital markets translate these differences in risk into differences in required return, in much the same way that differences in the characteristics of commodities are reflected in different prices.

The important point is that the required return on capital is set by supply and demand and is influenced by the relationship between the risk and return expected for those securities and the risks and returns expected from the overall menu of available securities.

Q. WHAT ECONOMIC AND FINANCIAL CONCEPTS HAVE GUIDED YOUR ASSESSMENT OF DUKE ENERGY KENTUCKY'S COST OF COMMON EQUITY?

A. Two fundamental economic principles underlie the appraisal of Duke Energy Kentucky's cost of equity, one relating to the supply side of capital markets, the other to the demand side.

On the supply side, the first principle asserts that rational investors maximize the performance of their portfolios only if they expect the returns on investments of comparable risk to be the same. If not, rational investors will switch out of those investments yielding lower returns at a given risk level in favor of those investment activities offering higher returns for the same degree of risk. This principle implies that a company will be unable to attract capital funds unless it can offer returns to capital suppliers that are comparable to those achieved on competing investments of similar risk.

On the demand side, the second principle asserts that a company will continue to invest in real physical assets if the return on these investments equals, or exceeds, a company's cost of capital. This principle suggests that a regulatory Commission should set rates at a level sufficient to create equality between the return on physical asset investments and a company's cost of capital.

Q. HOW DOES DUKE ENERGY KENTUCKY OBTAIN ITS CAPITAL AND HOW IS ITS OVERALL COST OF CAPITAL DETERMINED?

A. The funds employed by Duke Energy Kentucky are obtained in two general forms, debt capital and equity capital. The cost of debt funds can be ascertained easily from an examination of the contractual interest payments. The cost of common equity funds, that is, equity investors' required rate of return, is more difficult to estimate because the dividend payments received from common stock are not contractual or guaranteed in nature. They are uneven and risky, unlike interest payments. Once a cost of common equity estimate has been developed, it can then easily be combined with the embedded cost of debt based on the utility's capital structure, in order to arrive at the overall cost of capital (overall rate of return).

Q. WHAT IS THE MARKET REQUIRED RATE OF RETURN ON EQUITY CAPITAL?

A. The market required rate of return on common equity, or cost of equity, is the return demanded by the equity investor. Investors establish the price for equity capital through their buying and selling decisions in capital markets. Investors set return requirements according to their perception of the risks inherent in the investment, recognizing the opportunity cost of forgone investments in other companies, and the returns available from other investments of comparable risk.

Q. WHAT MUST BE CONSIDERED IN ESTIMATING A FAIR ROE?

A. The basic premise is that the allowable ROE should be commensurate with returns on investments in other firms having corresponding risks. The allowed return should be sufficient to assure confidence in the financial integrity of the firm, in order to maintain creditworthiness and ability to attract capital on reasonable terms. The "attraction of capital" standard focuses on investors' return requirements that are generally determined using market value methods, such as the DCF, CAPM, or risk premium methods. These market value tests define "fair return" as the return investors anticipate when they purchase equity shares of comparable risk in the financial marketplace. This is a market rate of return, defined in terms of anticipated dividends and capital gains as determined by expected changes in stock prices, and reflects the opportunity cost of capital. The economic basis for market value tests is that new capital will be attracted to a firm only if the return expected by the suppliers of funds is commensurate with that available from alternative investments of comparable risk.

III. COST OF EQUITY CAPITAL ESTIMATES

Q. HOW DID YOU ESTIMATE A FAIR ROE FOR DUKE ENERGY KENTUCKY'S NATURAL GAS BUSINESS?

A. To estimate a fair ROE for Duke Energy Kentucky, I employed three methodologies:

(i) DCF methodology;

(ii) CAPM methodology; and

(iii) Risk Premium methodology.

All three methodologies are standard market-based methodologies designed to estimate the return required by investors on the common equity capital committed to Duke Energy Kentucky.

Q. WHY DID YOU USE MORE THAN ONE APPROACH FOR ESTIMATING THE COST OF EQUITY?

A. No one single method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due to a recent merger, impending merger or acquisition, and a new corporate identity due to restructuring activities. The advantage of using several different approaches is that the results of each one can be used to check the others.

As a general proposition, it is extremely unreliable to use only one generic methodology to estimate equity costs. The difficulty is compounded when only one variant of that methodology is employed. It is compounded even further when that one methodology is applied to a single company. Hence, several methodologies applied to several comparable risk companies should be employed to estimate the cost of common equity.

As I have stated, there are three broad generic methods available to measure the cost of equity: DCF, CAPM, and risk premium. All three of these methods are accepted and used by the financial community and firmly supported in the financial literature. The weight accorded to any one method may vary depending on unusual circumstances in capital market conditions.

Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the method and on the reasonableness of the proxies used to validate the theory and apply the method. Each method has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. There is no guarantee that a single DCF result is necessarily the ideal predictor of the stock price and of the cost of equity reflected in that price, just as there is no guarantee that a single CAPM or risk premium result constitutes the perfect explanation of a stock's price or the cost of equity. In short, the utilization of multiple methodologies is critical, and reliance on a single methodology is unsound.

A. DCF Estimates

Q. PLEASE DESCRIBE THE DCF APPROACH TO ESTIMATING THE COST OF EQUITY CAPITAL.

A. According to DCF theory, the value of any security to an investor is the expected discounted value of the future stream of dividends or other benefits. One widely used method to measure these anticipated benefits in the case of a non-static company is to examine the current dividend plus the increases in future dividend payments expected by investors. This valuation process can be represented by the following formula, which is the traditional DCF model:

$$K_e = D_1/P_0 + g$$

where: K_e = investors' expected return on equity

D_1 = expected dividend at the end of the coming year

P_0 = current stock price

g = expected growth rate of dividends, earnings, stock price, and book value

The traditional DCF formula states that under certain assumptions, which are described in the next paragraph, the equity investor's expected return (K_e) can be viewed as the sum of an expected dividend yield (D_1/P_0) plus the expected growth rate of future dividends and stock price (g). The returns anticipated at a given market price are not directly observable and must be estimated from statistical market information. The idea of the market value approach is to infer K_e from the observed share price, the observed dividend, and an estimate of investors' expected future growth.

The assumptions underlying this valuation formulation are well known, and are discussed in detail in Chapter 8 of my more reference text, *The New Regulatory Finance*. The standard DCF model requires the following main assumptions:

(i) a constant average growth trend for both dividends and earnings;

(ii) a stable dividend payout policy;

(iii) a discount rate in excess of the expected growth rate; and

(iv) a constant price-earnings multiple, which implies that growth in price is synonymous with growth in earnings and dividends.

The standard DCF model also assumes that dividends are paid at the end of each year when in fact dividend payments are normally made on a quarterly basis.

Q. HOW DID YOU ESTIMATE DUKE ENERGY KENTUCKY'S COST OF EQUITY WITH THE DCF MODEL?

A. In estimating Duke Energy Kentucky's cost of equity, I applied the DCF model to a group of natural gas distribution utilities and to a group of combination gas and electric utilities, all of which are covered in the Value Line database.

In order to apply the DCF model, two components are required: the expected dividend yield (D_1/P_0), and the expected long-term growth (g). The expected dividend (D_1) in the annual DCF model can be obtained by multiplying the current indicated annual dividend rate by the growth factor (1 + g).

Q. HOW DID YOU ESTIMATE THE DIVIDEND YIELD COMPONENT OF THE DCF MODEL?

A. From a conceptual viewpoint, the stock price to employ in calculating the dividend yield is the then-current price of the security at the time of estimating the cost of equity. This is because the current stock prices provide a better indication of expected future prices than any other price in an efficient market. An efficient market implies that prices adjust rapidly to the arrival of new information. Therefore, current prices reflect the fundamental economic value of a security. A considerable body of empirical evidence indicates that capital markets are efficient with respect to a broad set of information. This implies that observed current prices represent the fundamental value of a security, and that a cost of capital estimate should be based on current prices.

In implementing the DCF model, I have used the current dividend yields reported in the Zacks Investment Research Web site (Zacks) in mid-July 2018. Basing dividend yields on average results from a large group of companies reduces the concern that the vagaries of individual company stock prices will result in an unrepresentative dividend yield.

Q. WHY DID YOU MULTIPLY THE SPOT DIVIDEND YIELD BY (1 + g) RATHER THAN BY (1 + 0.5g)?

A. Some analysts multiply the spot dividend yield by one plus one half the expected growth rate (1 + 0.5g) rather than the conventional one plus the expected growth rate (1 + g). This procedure (1 + 0.5g) understates the return expected by the investor.

The fundamental assumption of the basic annual DCF model is that dividends are received annually at the end of each year and that the first dividend is to be received one year from now. Thus, the appropriate dividend to use in a DCF model is the full prospective dividend to be received at the end of the year. Since the appropriate dividend to use in a DCF model is the prospective dividend one year from now rather than the dividend one-half year from now, multiplying the spot dividend yield by (1 + 0.5g) understates the proper dividend yield.

Moreover, the basic annual DCF model ignores the time value of quarterly dividend payments and assumes dividends are paid once a year at the end of the year. Multiplying the spot dividend yield by (1 + g) is actually a conservative attempt to capture the reality of quarterly dividend payments. Use of this method is conservative in the sense that the annual DCF model fully ignores the more frequent compounding of quarterly dividends.

Q. HOW DID YOU ESTIMATE THE GROWTH COMPONENT OF THE DCF MODEL?

A. The principal difficulty in calculating the required return by the DCF approach is in ascertaining the growth rate that investors currently expect. Since no explicit estimate of expected growth is observable, proxies must be employed.

As proxies for expected growth, I examined the consensus growth estimate developed by professional analysts. Projected long-term growth rates actually used by institutional investors to determine the desirability of investing in different securities influence investors' growth anticipations. These forecasts are made by large reputable organizations, and the data are readily available and are representative of the consensus view of investors. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts influence investor growth expectations and provide a sound basis for estimating the cost of equity with the DCF model.

Growth rate forecasts of several analysts are available from published investment newsletters and from systematic compilations of analysts' forecasts, such as those tabulated by Zacks. I used analysts' long-term growth forecasts reported in Zacks as proxies for investors' growth expectations in applying the DCF model. I also used Value Line's growth forecasts as additional proxies.

Q. WHY DID YOU REJECT THE USE OF HISTORICAL GROWTH RATES IN APPLYING THE DCF MODEL TO UTILITIES?

A. I have rejected historical growth rates as proxies for expected growth in the DCF calculation for two reasons. First, historical growth patterns are already incorporated in analysts' growth forecasts that should be used in the DCF model, and are therefore redundant. Second, published studies in the academic literature demonstrate that growth forecasts made by security analysts are reasonable indicators of investor expectations and that investors rely on analysts' forecasts. This considerable literature is summarized in Chapter 9 of my most recent textbook, *The New Regulatory Finance*.

Q. DID YOU CONSIDER ANY OTHER METHOD OF ESTIMATING EXPECTED GROWTH TO APPLY THE DCF MODEL?

A. Yes, I did. I considered using the so-called "sustainable growth" method, also referred to as the "retention growth" method. According to this method, future growth is estimated by multiplying the fraction of earnings expected to be retained by the company, 'b', by the expected return on book equity, ROE, as follows:

$$g = b \times ROE$$

where: g = expected growth rate in earnings/dividends

b = expected retention ratio

ROE = expected return on book equity

Q. DO YOU HAVE ANY RESERVATIONS IN REGARDS TO THE SUSTAINABLE GROWTH METHOD?

A. Yes, I do. First, the sustainable method of predicting growth contains a logic trap: the method requires an estimate of expected return on book equity to be implemented. But if the expected return on book equity input required by the model differs from the recommended return on equity, a fundamental contradiction in logic follows. Second, the empirical finance literature demonstrates that the sustainable growth method of determining growth is not as significantly correlated to measures of value, such as stock prices and price/earnings ratios, as analysts' growth forecasts. I therefore chose not to rely on this method.

Q. DID YOU CONSIDER DIVIDEND GROWTH IN APPLYING THE DCF MODEL?

A. No, not at this time. The reason is that as a practical matter, while there is an abundance of earnings growth forecasts, there are very few forecasts of dividend growth. As a result, investors' attention has shifted from dividends to earnings. In addition, earnings growth provides a more meaningful guide to investors' long-term growth expectations. Indeed, it is growth in earnings that will support future dividends and share prices.

Q. IS THERE ANY EMPIRICAL EVIDENCE DOCUMENTING THE IMPORTANCE OF EARNINGS IN EVALUATING INVESTORS' EXPECTATIONS?

A. Yes, there is an abundance of evidence attesting to the importance of earnings in assessing investors' expectations. First, the sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. To illustrate, Value Line, Yahoo Finance, Zacks, First Call Thompson, Reuters, and Multex provide comprehensive compilations of investors' earnings forecasts. The fact that these investment information providers focus on growth in earnings rather than growth in dividends indicates that the investment community regards earnings growth as a superior indicator of future long-term growth. Second, Value Line's principal investment rating assigned to individual stocks, Timeliness Rank, is based primarily on earnings, which accounts for 65% of the ranking.

Q. HOW DID YOU APPROACH THE COMPOSITION OF COMPARABLE GROUPS IN ORDER TO ESTIMATE DUKE ENERGY KENTUCKY'S COST OF EQUITY WITH THE DCF METHOD?

A. Because Duke Energy Kentucky is not publicly traded, the DCF model cannot be applied to Duke Energy Kentucky and proxies must be used. There are two possible approaches in forming proxy groups of companies.

The first approach is to apply cost of capital estimation techniques to a select group of companies directly comparable in risk to Duke Energy Kentucky. These companies are chosen by the application of stringent screening criteria to a universe of utility stocks in an attempt to identify companies with the same investment risk as Duke Energy Kentucky. Examples of screening criteria include bond rating, beta risk, size, percentage of revenues from utility operations, and common equity ratio. The end result is a small sample of companies with a risk profile similar to that of Duke Energy Kentucky, provided the screening criteria are defined and applied correctly.

The second approach is to apply cost of capital estimation techniques to a large group of utilities representative of the utility industry average and then make adjustments to account for any difference in investment risk between the company and the industry average, if any. As explained below, in view of substantial changes in circumstances in the utility industry, I have chosen the latter approach.

In the unstable capital market environments, it is important to select relatively large sample sizes representative of the utility industry as a whole, as opposed to small sample sizes consisting of a handful of companies. This is because the equity market as a whole and utility industry capital market data are volatile. As a result of this volatility, the composition of small groups of companies is very fluid, with companies exiting the sample due to dividend suspensions or reductions, insufficient or unrepresentative historical data due to recent mergers, impending merger or acquisition, and changing corporate identities due to restructuring activities.

From a statistical standpoint, confidence in the reliability of the DCF model result is considerably enhanced when applying the DCF model to a large group of companies. Any distortions introduced by measurement errors in the two DCF components of equity return for individual companies, namely dividend yield and growth are mitigated. Utilizing a large portfolio of companies reduces the influence of either overestimating or underestimating the cost of equity for any one individual company. For example, in a large group of companies, positive and negative deviations from the expected growth will tend to cancel out owing to the law of large numbers, provided that the errors are independent.[1] The average growth rate of several companies is less likely to diverge from expected growth than is the estimate of growth for a single firm. More generally, the assumptions

---

[1] If σ_i^2 represents the average variance of the errors in a group of N companies, and σ_{ij} the average covariance between the errors, then the variance of the error for the group of N companies, σ_N^2 is:

$$\sigma_N^2 = \frac{1}{N}\bar{\sigma}_i^2 + \frac{N-1}{N}\bar{\sigma}_{ij}$$

If the errors are independent, the covariance between them (σ_{ij}) is zero, and the variance of the error for the group is reduced to:

$$\sigma_N^2 = \frac{1}{N}\sigma_i^2$$

As N gets progressively larger, the variance gets smaller and smaller.

of the DCF model are more likely to be fulfilled for a large group of companies than for any single firm or for a small group of companies.

Moreover, small samples are subject to measurement error, and in violation of the Central Limit Theorem of statistics.[2] From a statistical standpoint, reliance on robust sample sizes mitigates the impact of possible measurement errors and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due to a recent merger, impending merger or acquisition, and a new corporate identity due to restructuring.

The point of all this is that the use of a handful of companies in a highly fluid and unstable industry produces fragile and statistically unreliable results. A more accurate procedure is to employ large sample sizes representative of the industry as a whole and apply subsequent risk adjustments to the extent that the company's risk profile differs from that of the industry average.

Q. CAN YOU DESCRIBE YOUR FIRST PROXY GROUP FOR DUKE ENERGY KENTUCKY'S NATURAL GAS UTILITY BUSINESS?

A. As a first proxy for Duke Energy Kentucky, I examined a group of investment-grade dividend-paying natural gas utilities contained in Value Line's natural gas distribution universe. This group of natural gas distribution utilities, displayed on

---

[2] The Central Limit Theorem describes the characteristics of the distribution of values we would obtain if we were able to draw an infinite number of random samples of a given size from a given population and we calculated the mean of each sample. The Central Limit Theorem asserts: [1] The mean of the sampling distribution of means is equal to the mean of the population from which the samples were drawn. [2] The variance of the sampling distribution of means is equal to the variance of the population from which the samples were drawn divided by the size of the samples. [3] If the original population is distributed normally, the sampling distribution of means will also be normal. If the original population is not normally distributed, the sampling distribution of means will increasingly approximate a normal distribution as sample size increases.

Duke Energy Kentucky Attachment RAM- 2, possesses utility assets similar to Duke Energy Kentucky's natural gas business.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR DUKE ENERGY KENTUCKY USING VALUE LINE GROWTH PROJECTIONS?

A. The DCF analysis for the natural gas utilities group using Value Line growth projections is shown on Duke Energy Kentucky Attachment RAM-3. As shown on Column 3 line 13 of Duke Energy Kentucky Attachment RAM-3, the average long-term growth forecast obtained from Value Line is 7.48% for the natural gas distribution group. Combining this growth rate with the average expected dividend yield of 2.72% shown in Column 4 line 13 produces an estimate of equity costs of 10.20% shown in Column 5. Recognition of flotation costs brings the cost of equity estimate to 10.35%, shown in Column 6. The need for a flotation cost allowance is discussed at length later in my testimony.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR DUKE ENERGY KENTUCKY USING ANALYSTS' GROWTH PROJECTIONS?

A. The DCF analysis for the natural gas utilities group using analyst growth projections is shown on Duke Energy Kentucky Attachment RAM-4. Repeating the exact same procedure as above, only this time using the Zacks earnings growth forecast of 6.92% instead of the Value Line forecast, the cost of equity for the natural gas distribution group is 9.63%, unadjusted for flotation costs. Adding an allowance for flotation costs brings the cost of equity estimate to 9.77%.

Q. CAN YOU DESCRIBE YOUR SECOND PROXY GROUP FOR DUKE ENERGY KENTUCKY'S NATURAL GAS UTILITY BUSINESS?

A. It is reasonable to postulate that the Company's natural gas utility operations possess an investment risk profile similar to the combination gas and electric utility business. Combination gas and electric utilities are reasonable proxies for natural gas distribution utilities, because they possess economic characteristics very similar to those of natural gas utilities. They are both involved in the transmission-distribution of energy services products at regulated rates in a cyclical and weather-sensitive market. They both employ a capital-intensive network with similar physical characteristics. They are both subject to rate of return regulation and have enjoyed similar allowed rates of return, attesting to their risk comparability. Because of this convergence and similarity, all these utilities are lumped in the same group by Standard and Poor's in defining bond rating benchmarks and assigning business risk scores.

Finally, as pointed out earlier, sole reliance on a smaller group of utilities is less reliable from a statistically viewpoint. The smaller the sample, the greater the likelihood of skewed results. I have therefore relied on this second proxy group of companies described below as well as on the natural gas utilities group.

Q. CAN YOU DESCRIBE YOUR SECOND PROXY GROUP FOR DUKE ENERGY KENTUCKY'S NATURAL GAS UTILITY BUSINESS?

A. As a second proxy for Duke Energy Kentucky's natural gas business, I examined a group of investment-grade dividend-paying combination gas and electric utilities covered in Value Line's Electric Utility industry group, meaning that these companies all possess utility assets similar to Duke Energy Kentucky's. I began with all the companies designated as combination gas and electric utilities that are also covered in the Value Line Investment Survey as shown on Duke Energy Kentucky Attachment RAM-5. Fortis was added to the group since it owns several US combination gas and electric utility companies. Private partnerships, private companies, non-dividend-paying companies, and companies below investment-grade (with a Moody's bond rating below Baa3) were eliminated, as well as those companies whose market capitalization was less than $1 billion, in order to minimize any stock price anomalies due to thin trading.[3] The final groups of companies only include those companies with a majority of their revenues from regulated utility operations.

From the preliminary list of 29 companies shown on Duke Energy Kentucky Attachment RAM-5, and as shown on the accompanying notes in the last column of that exhibit, I excluded the eleven companies marked with an X in Column 3. Column 4 shows the rationale for exclusion. The first excluded company was Avista Corp on account of its being acquired by Hydro One. The second excluded company was Empire District Electric, which was recently combined with a subsidiary of Liberty Utilities Co., the wholly owned regulated utility business subsidiary of Algonquin Power & Utilities Corp. The third excluded company was Entergy Corp. on account of its ongoing corporate restructuring and nuclear exposure. The fourth company was MDU Resources because its revenues from regulated utility operations were minimal. The fifth

[3] This is necessary in order to minimize the well-known thin trading bias in measuring beta. Unitil was excluded for this reason.

excluded company was Pepco Holdings, which has been merged with Exelon. The sixth excluded company was PG&E since it has suspended dividends. The seventh company excluded was SCANA on account of its nuclear construction exposure. Unitil was the eighth excluded company because of its very small size and because it is not covered in the Value Line database. The ninth and tenth excluded companies were CenterPoint and Vectren on account of the latter's acquisition by CenterPoint. Finally, the last excluded company was TECO Energy, which has been acquired by Emera.

The final group of 18 companies that comprise the proxy group is shown on Duke Energy Kentucky Attachment RAM-6. I stress that this proxy group must be viewed as a portfolio of comparable risk. It would be inappropriate to select any particular company or subset of companies from this group and infer the cost of common equity from that company or subset alone.

Q. WHAT DCF RESULTS DID YOU OBTAIN USING VALUE LINE GROWTH PROJECTIONS?

A. Duke Energy Kentucky Attachment RAM-7 displays the DCF analysis using Value Line growth projections for the 18 companies in Duke Energy Kentucky's second proxy group. As shown on column 3, line 20 of Duke Energy Kentucky Attachment RAM- 7, the average long-term earnings per share growth forecast obtained from Value Line is 6.33%. Combining this growth rate with the average expected dividend yield of 3.52% shown on column 4, line 20 produces an estimate of equity costs of 9.86% for the proxy group, as shown on column 5, line 20. Recognition of flotation costs brings the cost of equity estimate to 10.04% for the group, shown on Column 6, line 20. The need for a flotation cost allowance is discussed at length later in my testimony.

Q. WHAT DCF RESULTS DID YOU OBTAIN USING ANALYSTS' CONSENSUS GROWTH FORECASTS?

A. Duke Energy Kentucky Attachment RAM-8 displays the DCF analysis using analysts' consensus growth forecasts for the 18 companies in the proxy group. Please note that the growth forecast for MGE Energy was drawn from Value Line's growth forecast since the Zacks growth forecasts was not available for this company.

As shown on column 3, line 20 of Duke Energy Kentucky Attachment RAM-8, the average long-term earnings per share growth forecast obtained from analysts is 5.56% for the group. Combining this growth rate with the average expected dividend yield of 3.50% shown on column 4, line 20, produces an estimate of equity costs of 9.05% unadjusted for flotation cost, as shown on column 5, line 20. Recognition of flotation costs brings the cost of equity estimate to 9.24%, shown on Column 6, line 20.

Q. PLEASE SUMMARIZE THE DCF ESTIMATES FOR DUKE ENERGY KENTUCKY.

A. Table 1 below summarizes the DCF estimates for Duke Energy Kentucky:

Table 1. DCF Estimates for Duke Energy Kentucky

DCF STUDY	ROE
Natural Gas Util. Value Line Growth	10.35%
Natural Gas Util. Analysts Growth	9.77%
Gas & Elec Util. Value Line Growth	10.04%
Gas & Elect Util. Analysts Growth	9.24%

B. CAPM Estimates

Q. PLEASE DESCRIBE YOUR APPLICATION OF THE CAPM RISK PREMIUM APPROACH.

A. My first two risk premium estimates are based on the CAPM and on an empirical approximation to the CAPM (ECAPM). The CAPM is a fundamental paradigm of finance. Simply put, the fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta (β). According to the CAPM, securities are priced such that:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is stated as follows:

$$K = R_F + \beta \times (R_M - R_F)$$

where: K = investors' expected return on equity

R_F = risk-free rate

R_M = return on the market as a whole

β = systematic risk (i.e., change in a security's return relative to that of the market)

This is the seminal CAPM expression, which states that the return required by investors is made up of a risk-free component, R_F, plus a risk premium determined by $\beta \times (R_M - R_F)$. The bracketed expression $(R_M - R_F)$ expression is known as the market risk premium (MRP). To derive the CAPM risk premium estimate, three quantities are required: the risk-free rate (R_F), beta (β), and the MRP, (R_M - R_F).

For the risk-free rate (RF), I used 4.2%, based on forecast interest rates on long-term U.S. Treasury bonds.

For beta (β), I used 0.75 based on Value Line estimates.

For the MRP, I used 7.0% based on historical market risk premium studies and additional checks. These inputs to the CAPM are explained below.

Q. HOW DID YOU ARRIVE AT YOUR RISK-FREE RATE ESTIMATE OF 4.2% IN YOUR CAPM AND RISK PREMIUM ANALYSES?

A. To implement the CAPM and Risk Premium methods, an estimate of the risk-free return is required as a benchmark. I relied on noted economic forecasts which call for a rising trend in interest rates in response to the recovering economy, anticipated renewed inflation, and high federal deficits. Value Line, Global Insight, the Congressional Budget Office, the Bureau of Labor Statistics, the Economic Report of the President, and the U.S. Energy Information Administration all project higher long-term Treasury bond rates in the future.

Q. WHY DID YOU RELY ON LONG-TERM BONDS INSTEAD OF SHORT-TERM BONDS?

A. The appropriate proxy for the risk-free rate in the CAPM is the return on the longest-term Treasury bond possible. This is because common stocks are very long-term instruments more akin to very long-term bonds rather than to short-term Treasury bills or intermediate-term Treasury notes. In a risk premium model, the ideal estimate for the risk-free rate has a term to maturity equal to the security being analyzed. Since common stock is a very long-term investment because the cash flows to investors in the form of dividends last indefinitely, the yield on the longest-term possible government bonds, that is the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the CAPM. The expected common stock return is based on very long-term cash flows, regardless of an individual's holding time period. Moreover, utility asset investments generally have very long-term useful lives and should correspondingly be matched with very long-term maturity financing instruments.

While long-term Treasury bonds are potentially subject to interest rate risk, this is only true if the bonds are sold prior to maturity. A substantial fraction of bond market participants, usually institutional investors with long-term liabilities (*e.g.*, pension funds and insurance companies), in fact hold bonds until they mature, and therefore are not subject to interest rate risk. Moreover, institutional bondholders neutralize the impact of interest rate changes by matching the maturity of a bond portfolio with the investment planning period, or by engaging in hedging transactions in the financial futures markets. The merits and mechanics of such immunization strategies are well documented by both academicians and practitioners.

Another reason for utilizing the longest maturity Treasury bond possible is that common equity has an infinite life span, and the inflation expectations embodied in its market-required rate of return will therefore be equal to the inflation rate anticipated to prevail over the very long term. The same expectation should be embodied in the risk-free rate used in applying the CAPM model. It stands to reason that the yields on 30-year Treasury bonds will more closely incorporate within their yields the inflation expectations that influence the prices of common stocks than do short-term Treasury bills or intermediate-term U.S. Treasury notes.

Among U.S. Treasury securities, 30-year Treasury bonds have the longest term to maturity and the yields on such securities should be used as proxies for the risk-free rate in applying the CAPM. Therefore, I have relied on the yield on 30-year Treasury bonds in implementing the CAPM and risk premium methods.

Q. ARE THERE OTHER REASONS WHY YOU REJECT SHORT-TERM INTEREST RATES AS PROXIES FOR THE RISK-FREE RATE IN IMPLEMENTING THE CAPM?

A. Yes. Short-term rates are volatile, fluctuate widely, and are subject to more random disturbances than are long-term rates. Short-term rates are largely administered rates. For example, Treasury bills are used by the Federal Reserve as a policy vehicle to stimulate the economy and to control the money supply, and are used by foreign governments, companies, and individuals as a temporary safe-house for money.

As a practical matter, it makes no sense to match the return on common stock to the yield on 90-day Treasury Bills. This is because short-term rates, such as the yield on 90-day Treasury Bills, fluctuate widely, leading to volatile and unreliable equity return estimates. Moreover, yields on 90-day Treasury Bills typically do not match the equity investor's planning horizon. Equity investors generally have an investment horizon far in excess of 90 days.

As a conceptual matter, short-term Treasury Bill yields reflect the impact of factors different from those influencing the yields on long-term securities such as common stock. For example, the premium for expected inflation embedded into 90-day Treasury Bills is likely to be far different than the inflationary premium embedded into long-term securities yields. On grounds of stability and consistency, the yields on long-term Treasury bonds match more closely with common stock returns.

Q. WHAT IS YOUR ESTIMATE OF THE RISK-FREE RATE IN APPLYING THE CAPM?

A. All the noted interest rate forecasts that I am aware of point to significantly higher interest rates over the next several years. Table 2 below reports the forecast yields on 30-year US Treasury bonds from several prominent sources, including the Congressional Budget Office, Bureau of Labor Statistics, U.S. Energy Information Administration, HIS (formerly Global Insight), Value Line, and the Economic Report of the President.

Table 2 Forecast Yields on

30-year U.S. Treasury Bonds

Value Line Economic Forecast	4.00
U.S. Energy Information Administration (EIA)	4.57
Bureau of Labor Statistics (BLS)	5.80
Congressional Budget Office (CBO)	4.20
Economic Report of the President	4.20
White House Budget 2018	4.10
IHS (Global Insight)	3.92
AVERAGE	4.40
AVERAGE without the BLS forecast	**4.20**

The average long-term bond yield forecast from the seven sources is 4.4%, and becomes 4.2% if the outlying BLS forecast is excluded from the computation of the average. The remaining individual forecasts are quite consistent as they are closely clustered around the average. Based on this evidence, a long-term bond yield forecast of 4.2% is a reasonable estimate of the expected risk-free rate for purposes of forward-looking CAPM/ECAPM and Risk Premium analyses in the current economic environment.

Q. WHY DID YOU IGNORE THE CURRENT LEVEL OF INTEREST RATES IN DEVELOPING YOUR PROXY FOR THE RISK-FREE RATE IN A CAPM ANALYSIS?

A. I relied on projected long-term Treasury interest rates for three reasons. First, investors price securities on the basis of long-term expectations, including interest rates. Cost of capital models, including both the CAPM and DCF models, are prospective (*i.e.*, forward-looking) in nature and must take into account current market expectations for the future because investors price securities on the basis of long-term expectations, including interest rates. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using data that reflects the expectations of actual investors in the market. While investors examine history as a guide to the future, it is the expectations of future events that influence security values and the cost of capital.

Second, Investors' required returns can and do shift over time with changes in capital market conditions, hence the importance of considering interest rate forecasts. The fact that organizations such as Value Line, IHS (Global Insight), EIA, and CBO among many others devote considerable expertise and resources to developing an informed view of the future, and the fact that investors are willing to purchase such expensive services confirm the importance of economic/financial forecasts in the minds of investors. Moreover, the empirical evidence demonstrates that stock prices do indeed reflect prospective financial input data.

Third, given that this proceeding is to provide ROE estimates for future proceedings, forecast interest rates are far more relevant. The use of interest rate forecasts is no different than the use of projections of other financial variables in DCF analyses.

Q. HOW DID YOU SELECT THE BETA FOR YOUR CAPM ANALYSIS?

A. A major thrust of modern financial theory as embodied in the CAPM is that perfectly diversified investors can eliminate the company-specific component of risk and that only market risk remains. The latter is technically known as "beta" (β), or "systematic risk". The beta coefficient measures change in a security's return relative to that of the market. The beta coefficient states the extent and direction of movement in the rate of return on a stock relative to the movement in the rate of return on the market as a whole. It indicates the change in the rate of return on a stock associated with a one percentage point change in the rate of return on the market, and thus measures the degree to which a particular stock shares the risk of the market as a whole. Modern financial theory has established that beta incorporates several economic characteristics of a corporation that are reflected in investors' return requirements.

Duke Energy Kentucky common stock is not publicly traded and, therefore, proxies must be used. In the discussion of DCF estimates of the cost of common equity earlier, I examined a group of investment-grade dividend-paying natural gas distribution utilities covered by Value Line. As shown on Duke Energy Kentucky Attachment RAM-9, the average beta for this group is 0.75. Based on these results, I shall use 0.75, as an estimate for the beta applicable to Duke Energy Kentucky's natural gas business.

Q. WHAT MRP DID YOU USE IN YOUR CAPM ANALYSIS?

A. For the MRP, I used 7.0%. This estimate was based on the results of historical studies of long-term risk premiums and on two additional checks. Specifically, the historical MRP estimate is based on the results obtained in Duff & Phelps' 2017 Valuation Handbook (formerly published by Morningstar and earlier by Ibbotson Associates), which compiles historical returns from 1926 to 2017. This well-known study shows that a very broad market sample of common stocks outperformed long-term U.S. Government bonds by 6.0%. The historical MRP over the income component of long-term U.S. Government bonds rather than over the total return is 7.0%.

The historical MRP should be computed using the income component of bond returns because the intent, even using historical data, is to identify an expected MRP. The income component of total bond return (*i.e.,* the coupon rate) is a far better estimate of expected return than the total return *(i.e.*, the coupon rate + capital gain), because both realized capital gains and realized losses are largely unanticipated by bond investors. The long-horizon (1926-2017) MRP is 7.0%.

As a first check on my 7.0% MRP estimate, I examined the historical return on common stocks in real terms (inflation-adjusted) over the 1926-2016 period and added current inflation expectations to arrive at a current inflation-adjusted common stock return. According to the Duff & Phelps study, the average historical return on common stocks averaged 12.0% over the 1926-2016 period while inflation averaged 3.0% over the same period, implying a real return of 9.0% (12.0% - 3.0% = 9.0%). With current long-term inflation expectations of 2.1%,[4] the inflation-adjusted return on common stock becomes 11.0% (9.0% + 2.1% = 11.1%). Given the forecast yield of 4.2%, the implied MRP is 6.9% (11.1% - 4.2% = 6.9%) which is almost identical to the 7.0% estimate.

As a second check on the 7.0% estimate, I examined Value Line's dividend yield and growth forecasts for the 1700 stocks in the Value Line Stock

[4] 30-year U.S. Treasury bonds are currently trading at a 2.9% yield while 30-year inflation-adjusted bonds are trading at an approximate yield of 0.8%, implying a long-term inflation rate expectation of 2.1%.

Index, that is, for the broad U.S. economy.[5] Value Line's dividend yield forecast for the latter is 2.0%, and its forecast 3- to 5-year appreciation potential for these companies is 45%. The latter figure for the 4-year period (the midpoint of the 3- to 5-year forecast period) implies an annual growth potential of 8.8%. Adding the 2.0% dividend yield to this annual growth rate produces a market return of 10.8%. Subtracting the current yield of 3.0% on 30-year Treasury bonds from the market return produces a market risk premium of 7.8%. Subtracting the forecast yield of 4.2% instead of the current yield produces a market risk premium of 6.6%. The resulting MRP range of 6.6% - 7.8% (midpoint 7.2%) is therefore quite consistent with my MRP estimate of 7.0%.

Q. IS YOUR MRP ESTIMATE OF 7.0% CONSISTENT WITH THE ACADEMIC LITERATURE ON THE SUBJECT?

A. Yes, it is, although in the upper portion of the range. In their authoritative corporate finance textbook, Professors Brealey, Myers, and Allen[6] conclude from their review of the fertile literature on the MRP that a range of 5% to 8% is reasonable for the MRP in the United States. My own survey of the MRP literature, which appears in Chapter 5 of my latest textbook, The New Regulatory Finance, is also quite consistent with this range.

Q. ON WHAT MATURITY BOND DOES THE DUFF & PHELPS HISTORICAL RISK PREMIUM DATA RELY?

A. Because 30-year bonds were not always traded or even available throughout the

[5] *See* Value Line Summary and Index July 20, 2018 issue.

[6] Richard A. Brealey, Stewart C. Myers, and Paul Allen, Principles of Corporate Finance, 8th Edition, Irwin McGraw-Hill, 2006.

entire 1926-2017 period covered in the Duff & Phelps study of historical returns, the latter study relied on bond return data based on 20-year Treasury bonds. Given that the normal yield curve is virtually flat above maturities of 20 years over most of the period covered in the Duff & Phelps study, the difference in yield is not material.

Q. WHY DID YOU USE LONG TIME PERIODS IN ARRIVING AT YOUR HISTORICAL MRP ESTIMATE?

A. Because realized returns can be substantially different from prospective returns anticipated by investors when measured over short time periods, it is important to employ returns realized over long time periods rather than returns realized over more recent time periods when estimating the MRP with historical returns. Therefore, a risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge.

I have therefore ignored realized risk premiums measured over short time periods. Instead, I relied on results over periods of enough length to smooth out short-term aberrations, and to encompass several business and interest rate cycles. The use of the entire study period in estimating the appropriate MRP minimizes subjective judgment and encompasses many diverse regimes of inflation, interest rate cycles, and economic cycles.

To the extent that the estimated historical equity risk premium follows what is known in statistics as a random walk, one should expect the equity risk premium to remain at its historical mean. Since I found no evidence that the MRP in common stocks has changed over time, at least prior to the onslaught of the financial crisis of 2008-2009, that is, no significant serial correlation in the Duff & Phelps study prior to that time, it is reasonable to assume that these quantities will remain stable in the future.

Q. SHOULD STUDIES OF HISTORICAL RISK PREMIUMS RELY ON ARITHMETIC AVERAGE RETURNS OR GEOMETRIC AVERAGE RETURNS?

A. Whenever relying on historical risk premiums, only arithmetic average returns over long periods are appropriate for forecasting and estimating the cost of capital, and geometric average returns are not.[7]

Q. PLEASE EXPLAIN HOW THE ISSUE OF WHAT IS THE PROPER "MEAN" ARISES IN THE CONTEXT OF ANALYZING THE COST OF EQUITY?

A. The issue arises in applying methods that derive estimates of a utility's cost of equity from historical relationships between bond yields and earned returns on equity for individual companies or portfolios of several companies. Those methods produce series of numbers representing the annual difference between bond yields and stock returns over long historical periods. The question is how to translate those series into a single number that can be added to a current bond yield to estimate the current cost of equity for a stock or a portfolio. Calculating

---

[7] *See* Roger A. Morin, Regulatory Finance: Utilities' Cost of Capital, Chapter 11 (1994); Roger A. Morin, The New Regulatory Finance: Utilities' Cost of Capital, Chapter 4 (2006); Richard A Brealey, *et al.*, Principles of Corporate Finance (8th ed. 2006).

geometric and arithmetic means are two ways of converting series of numbers to a single, representative figure.

Q. IF BOTH ARE "REPRESENTATIVE" OF THE SERIES, WHAT IS THE DIFFERENCE BETWEEN THE TWO MEANS?

A. Each mean represents different information about the series. The geometric mean of a series of numbers is the value which, if compounded over the period examined, would have made the starting value to grow to the ending value. The arithmetic mean is simply the average of the numbers in the series. Where there is any annual variation (volatility) in a series of numbers, the arithmetic mean of the series, which reflects volatility, will always exceed the geometric mean, which ignores volatility. Because investors require higher expected returns to invest in a company whose earnings are volatile than one whose earnings are stable, the geometric mean is not useful in estimating the expected rate of return which investors require to make an investment.

Q. CAN YOU PROVIDE A NUMERICAL EXAMPLE TO ILLUSTRATE THIS DIFFERENCE BETWEEN GEOMETRIC AND ARITHMETIC MEANS?

A. Yes. Table 3 below compares the geometric and arithmetic mean returns of a hypothetical Stock A, whose yearly returns over a ten-year period are very volatile, with those of a hypothetical Stock B, whose yearly returns are perfectly stable during that period. Consistent with the point that geometric returns ignore volatility, the geometric mean returns for the two series are identical (11.6% in both cases), whereas the arithmetic mean return of the volatile stock (26.7%) is much higher than the arithmetic mean return of the stable stock (11.6%).

If relying on geometric means, investors would require the same expected return to invest in both of these stocks, even though the volatility of returns in Stock A is very high while Stock B exhibits perfectly stable returns. That is clearly contrary to the most basic financial theory, that is, the higher the risk the higher the expected return.

Table 3. Arithmetic vs Geometric Mean Returns

Year	***Stock A***	***Stock B***
2006	50.0%	11.6%
2007	-54.7%	11.6%
2008	98.5%	11.6%
2009	42.2%	11.6%
2010	-32.3%	11.6%
2011	-39.2%	11.6%
2012	153.2%	11.6%
2013	-10.0%	11.6%
2014	38.9%	11.6%
2015	20.0%	11.6%
Std. Deviation	64.9%	0.0%
Arith Mean	26.7%	11.6%
Geom Mean	11.6%	11.6%

Chapter 4 Appendix A of my book The New Regulatory Finance contains a detailed and rigorous discussion of the impropriety of using geometric averages in estimating the cost of capital. Briefly, the disparity between the arithmetic average return and the geometric average return raises the question as to what purposes should these different return measures be used. The answer is that the

geometric average return should be used for measuring historical returns that are compounded over multiple time periods. The arithmetic average return should be used for future-oriented analysis, where the use of expected values is appropriate. It is inappropriate to average the arithmetic and geometric average return; they measure different quantities in different ways.

Q. WHAT IS YOUR ESTIMATE OF DUKE ENERGY KENTUCKY'S COST OF EQUITY USING THE CAPM APPROACH?

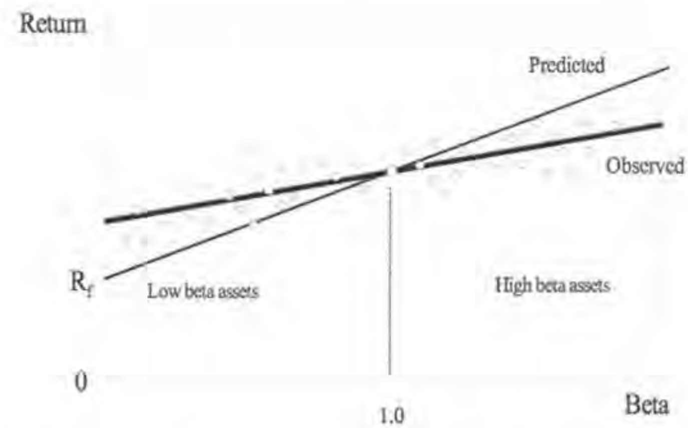
A. Inserting those input values into the CAPM equation, namely a risk-free rate of 4.2%, a beta of 0.75, and a MRP of 7.0%, the CAPM estimate of the cost of common equity is: 4.2% + 0.75 x 7.0% = 9.5%. This estimate becomes 9.7% with flotation costs, discussed later in my testimony.

Q. CAN YOU DESCRIBE YOUR APPLICATION OF THE EMPIRICAL VERSION OF THE CAPM?

A. There have been countless empirical tests of the CAPM to determine to what extent security returns and betas are related in the manner predicted by the CAPM. This literature is summarized in Chapter 6 of my latest book, <u>The New Regulatory Finance</u>. The results of the tests support the idea that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the risk-return tradeoff is not as steeply sloped as the predicted CAPM. That is, empirical research has long shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.

A CAPM-based estimate of cost of capital underestimates the return required from low-beta securities and overstates the return required from high-beta securities, based on the empirical evidence. This is one of the most well-known results in finance, and it is displayed graphically below.

CAPM: Predicted vs Observed Returns



A number of variations on the original CAPM theory have been proposed to explain this finding. The ECAPM makes use of these empirical findings. The ECAPM estimates the cost of capital with the equation:

$$K = R_F + \alpha + \beta \ x \ (MRP - \alpha)$$

where the symbol alpha, α, represents the "constant" of the risk-return line, MRP is the market risk premium (R_M - R_F), and the other symbols are defined as usual.

Inserting the long-term risk-free rate as a proxy for the risk-free rate, an alpha in the range of 1% - 2%, and reasonable values of beta and the MRP in the above equation produces results that are indistinguishable from the following more tractable ECAPM expression:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,\beta \quad (R_M - R_F)$$

An alpha range of 1% - 2% is somewhat lower than that estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. In other words, the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version which has been tested. This is also because the use of adjusted betas rather than the use of raw betas also incorporates some of the desired effect of using the ECAPM.[8] Thus, it is reasonable to apply a conservative alpha adjustment.

Please see Appendix A for a discussion of the ECAPM, including its theoretical and empirical underpinnings.

In short, the following equation provides a viable approximation to the observed relationship between risk and return, and provides the following cost of equity capital estimate:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75 \text{ x } (R_M - R_F)$$

Inserting the risk-free rate ($R_{F)}$ of 4.2%, a MRP (R_M - R_F) of 7.0%, and a beta of 0.75 in the above equation, the return on common equity is 9.9%. This estimate becomes 10.1% with flotation costs, discussed later in my testimony.

---

[8] The regression tendency of betas to converge to 1.0 over time is very well known and widely discussed in the financial literature. As a result of this beta drift, several commercial beta producers adjust their forecasted betas toward 1.00 in an effort to improve their forecasts. Value Line, Bloomberg, and Merrill Lynch betas are adjusted for their long-term tendency to regress toward 1.0 by giving approximately 66% -weight to the measured raw beta and approximately 33% weight to the prior value of 1.0 for each stock:

$$\beta_{adjusted} = 0.33 + 0.66\ \beta_{raw}$$

Q. IS THE USE OF THE ECAPM CONSISTENT WITH THE USE OF ADJUSTED BETAS?

A. Yes, it is. Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease in beta. The observed return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprise two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to the previous graph, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. Moreover, the use of adjusted betas compensates for interest rate sensitivity of utility stocks not captured by unadjusted betas.

Q. PLEASE SUMMARIZE YOUR CAPM ESTIMATES.

A. Table 4 below summarizes the common equity estimates obtained from the CAPM studies.

Table 4. CAPM Results

CAPM Method	ROE
Traditional CAPM	9.7%
Empirical CAPM	10.1%

C. Historical Risk Premium Estimates

Q. PLEASE DESCRIBE YOUR HISTORICAL RISK PREMIUM ANALYSIS OF THE UTILITY INDUSTRY USING TREASURY BOND YIELDS.

A. A historical risk premium for the utility industry was estimated with an annual time series analysis applied to the utility industry as a whole over the 1931-2017 period, using Standard and Poor's Utility Index (S&P Utility Index) as an industry proxy. The risk premium was estimated by computing the actual realized return on equity capital for the S&P Utility Index for each year, using the actual stock prices and dividends of the index, and then subtracting the long-term Treasury bond return for that year. Please see Duke Energy Kentucky Attachment RAM-10 for this analysis.

As shown on Duke Energy Kentucky Attachment RAM-10, the average risk premium over the period was 5.6% over long-term Treasury bond yields and 6.2% over the income component of bond yields. As discussed previously, the latter is the appropriate risk premium to use. Given the risk-free rate of 4.2%, and using the historical estimate of 6.2% for bond returns, the implied cost of equity is 4.2% + 6.2% = 10.4% without flotation costs and 10.6% with the flotation cost allowance.

Q. ARE YOU CONCERNED ABOUT THE REALISM OF THE ASSUMPTIONS THAT UNDERLIE THE HISTORICAL RISK PREMIUM METHOD?

A. No, I am not, for they are no more restrictive than the assumptions that underlie the DCF model or the CAPM. While it is true that the method looks backward in time and assumes that the risk premium is constant over time, these assumptions are not necessarily restrictive. By employing returns realized over long time periods rather than returns realized over more recent time periods, investor return expectations and realizations converge. Realized returns can be substantially different from prospective returns anticipated by investors, especially when measured over short time periods. By ensuring that the risk premium study encompasses the longest possible period for which data are available, short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge, or else, investors would be reluctant to invest money.

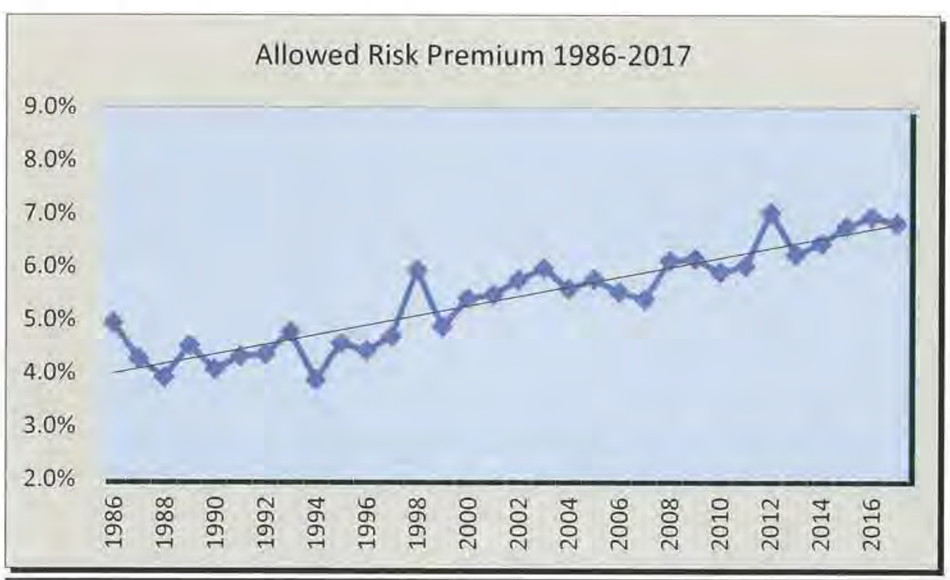
D. <u>Allowed Risk Premium Estimates</u>

Q. PLEASE DESCRIBE YOUR ANALYSIS OF ALLOWED RISK PREMIUMS IN THE GAS UTILITY INDUSTRY.

A. To estimate the gas utility industry's cost of common equity, I also examined the historical risk premiums implied in the ROEs allowed by regulatory commissions for gas utilities over the 1986-2017 period for which data were available, relative to the contemporaneous level of the long-term Treasury bond yield. Please see Duke Energy Kentucky Attachment RAM-11 for this analysis.

This variation of the risk premium approach is reasonable because allowed risk premiums are presumably based on the results of market-based methodologies (DCF, CAPM, Risk Premium, *etc.*) presented to regulators in rate hearings and on the actions of objective unbiased investors in a competitive marketplace. Historical allowed ROE data are readily available over long periods on a quarterly basis from Regulatory Research Associates (now S&P Global Intelligence) and easily verifiable from prior issues of that same publication and past commission decision archives.

The average ROE spread over long-term Treasury yields was 5.4% over the entire 1986-2017 period for which data were available from SNL. The graph below shows the year-by-year allowed risk premium. The escalating trend of the risk premium in response to lower interest rates and rising competition is noteworthy.

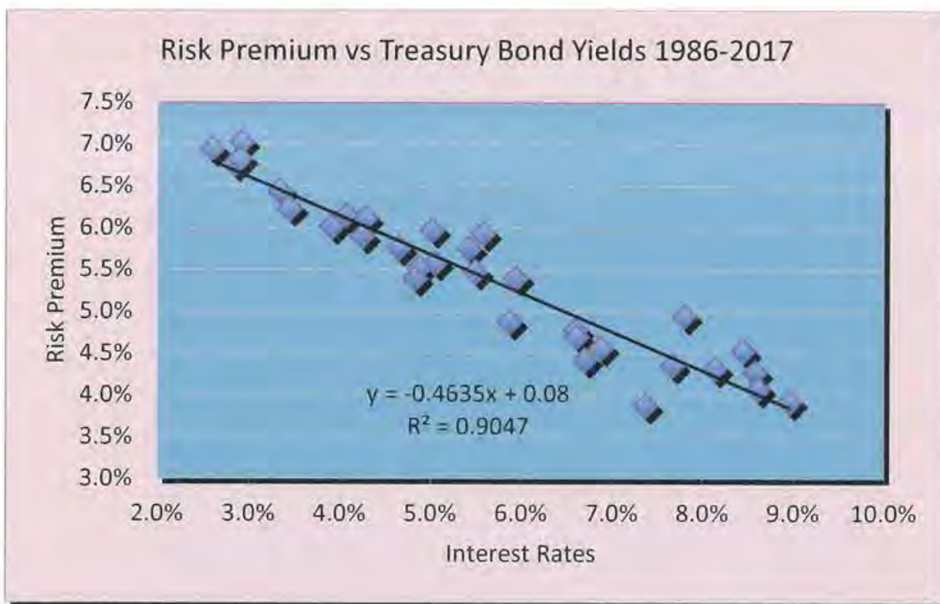


A careful review of these ROE decisions relative to interest rate trends reveals a narrowing of the risk premium in times of rising interest rates, and a widening of the premium as interest rates fall. The following statistical relationship between the risk premium (RP) and interest rates (YIELD) emerges over the 1986-2017 period:

$$RP = 8.0000 - 0.4635\ YIELD$$

$$R^2 = 0.90$$

The relationship is highly statistically significant[9] as indicated by the very high R^2. The graph below shows a clear inverse relationship between the allowed risk premium and interest rates as revealed in past ROE decisions.



Inserting the long-term Treasury bond yield of 4.2% in the above equation suggests a risk premium estimate of 6.0%, implying a cost of equity of 10.3%.

[9] The coefficient of determination R^2, sometimes called the "goodness of fit measure," is a measure of the degree of explanatory power of a statistical relationship. It is simply the ratio of the explained portion to the total sum of squares. The higher R^2 the higher is the degree of the overall fit of the estimated regression equation to the sample data.

Q. DO INVESTORS TAKE INTO ACCOUNT ALLOWED RETURNS IN FORMULATING THEIR RETURN EXPECTATIONS?

A. Yes, they do. Investors do indeed take into account returns granted by various regulators in formulating their risk and return expectations, as evidenced by the availability of commercial publications disseminating such data, including Value Line and SNL (formerly Regulatory Research Associates). Allowed returns, while certainly not a precise indication of a particular company's cost of equity capital, are nevertheless important determinants of investor growth perceptions and investor expected returns.

Q. PLEASE SUMMARIZE YOUR RISK PREMIUM ESTIMATES.

A. Table 5 below summarizes the ROE estimates obtained from the two risk premium studies.

Table 5. Risk Premium Estimates

Risk Premium Method	ROE
Historical Risk Premium Electric	10.6%
Allowed Risk Premium	10.3%

E. Need for Flotation Cost Adjustment

Q. PLEASE DESCRIBE THE NEED FOR A FLOTATION COST ALLOWANCE.

A. All the market-based estimates reported above include an adjustment for flotation costs. The simple fact of the matter is that issuing common equity capital is not free. Flotation costs associated with stock issues are similar to the flotation costs associated with bonds and preferred stocks. Flotation costs are not expensed at the time of issue, and therefore must be recovered via a rate of return adjustment.

This is done routinely for bond and preferred stock issues by most regulatory commissions, including FERC. Clearly, the common equity capital accumulated by the Company is not cost-free. The flotation cost allowance to the cost of common equity capital is discussed and applied in most corporate finance textbooks; it is unreasonable to ignore the need for such an adjustment.

Flotation costs are very similar to the closing costs on a home mortgage. In the case of issues of new equity, flotation costs represent the discounts that must be provided to place the new securities. Flotation costs have a direct and an indirect component. The direct component is the compensation to the security underwriter for marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (e.g., printing, legal, prospectus). The indirect component represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue. The latter component is frequently referred to as "market pressure."

Investors must be compensated for flotation costs on an ongoing basis to the extent that such costs have not been expensed in the past, and therefore the adjustment must continue for the entire time that these initial funds are retained in the firm. Appendix B to my testimony discusses flotation costs in detail, and shows: (1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital; (2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated;

and (3) that flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

By analogy, in the case of a bond issue, flotation costs are not expensed but are amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. The flotation adjustment is also analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the Company issues new debt capital in the future, until recovery is complete, in the same way that the recovery of past investments in plant and equipment through depreciation allowances continues in the future even if no new construction is contemplated. In the case of common stock that has no finite life, flotation costs are not amortized. Thus, the recovery of flotation costs requires an upward adjustment to the allowed return on equity.

Q. CAN YOU PROVIDE A NUMERICAL EXAMPLE TO ILLUSTRATE THE NEED FOR A FLOTATION COST ALLOWANCE?

A. Yes, a simple numerical example will illustrate the concept. A stock is sold for $100, and investors require a 10% return, that is, $10 of earnings. But if flotation costs are 5%, the Company nets $95 from the issue, and its common equity account is credited by $95. In order to generate the same $10 of earnings to the shareholders, from a reduced equity base, it is clear that a return in excess of 10% must be allowed on this reduced equity base, here 10.53%.

Q. WHAT DOES THE EMPIRICAL EVIDENCE HAVE TO SAY ON UTILITY FLOTATION COSTS?

A. According to the empirical finance literature discussed in Appendix B, total flotation costs amount to 4% for the direct component and 1% for the market pressure component, for a total of 5% of gross proceeds. This in turn amounts to approximately 20 basis points, depending on the magnitude of the dividend yield component. To illustrate, dividing the average expected dividend yield of around 4.0% for utility stocks by 0.95 yields 4.2%, which is 20 basis points higher.

Q. SHOULD FLOTATION COSTS BE TREATED LIKE ANY OTHER EXPENSE INCURRED BY THE UTILITY COMPANY?

A. I do not believe they should. In theory, flotation costs could be expensed and recovered through rates as they are incurred. This procedure, although simple in implementation, is not considered appropriate, however, because the equity capital raised in a given stock issue remains on the utility's common equity account and continues to provide benefits to customers indefinitely. It would be unfair to burden the current generation of customers with the full costs of raising capital when the benefits of that capital extend indefinitely. The common practice of capitalizing rather than expensing eliminates the intergenerational transfers that would prevail if today's customers were asked to bear the full burden of flotation costs of bond/stock issues in order to finance capital projects designed to serve future as well as current generations. Moreover, expensing flotation costs requires an estimate of the market pressure effect for each individual issue, which is likely to prove unreliable. A more reliable approach is to estimate market pressure for a large sample of stock offerings rather than for one individual issue.

Sometimes, the argument is also made that flotation costs are real and should be recognized in calculating the fair return on equity, but only at the time when the expenses are incurred. In other words, as the argument goes, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument is valid only if the Company has already been compensated for these costs. If not, the argument is without merit. My own recommendation is that investors be compensated for flotation costs on an on-going basis rather than through expensing and that the flotation cost adjustment continues for the entire time that these initial funds are retained in the firm.

There are several sources of equity capital available to a firm including: common equity issues, conversions of convertible preferred stock, dividend reinvestment plans, employees' savings plans, warrants, and stock dividend programs. Each carries its own set of administrative costs and flotation cost components, including discounts, commissions, corporate expenses, offering spread, and market pressure. The flotation cost allowance is a composite factor that reflects the historical mix of sources of equity. The allowance factor is a build-up of historical flotation cost adjustments associated with and traceable to each component of equity at its source. It is impractical and prohibitively costly to start from the inception of a company and determine the source of all present equity. A practical solution is to identify general categories and assign one factor to each category. My recommended flotation cost allowance is a weighted average cost factor designed to capture the average cost of various equity vintages and types of equity capital raised by the Company.

Q. DR. MORIN, CAN YOU PLEASE ELABORATE ON THE MARKET PRESSURE COMPONENT OF FLOTATION COST?

A. The indirect component, or market pressure component of flotation costs represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue, reflecting the basic economic fact that when the supply of securities is increased following a stock or bond issue, the price falls. The market pressure effect is real, tangible, measurable, and negative. According to the empirical finance literature cited in Appendix B, the market pressure component of the flotation cost adjustment is approximately 1% of the gross proceeds of an issuance. The announcement of the sale of large blocks of stock produces a decline in a company's stock price, as one would expect given the increased supply of common stock.

Q. IS A FLOTATION COST ADJUSTMENT REQUIRED FOR AN OPERATING SUBSIDIARY LIKE DUKE ENERGY KENTUCKY THAT DOES NOT TRADE PUBLICLY?

A. Yes, it is. It is sometimes alleged that a flotation cost allowance is inappropriate if the utility is a subsidiary whose equity capital is obtained from its ultimate owner, in this case, Duke Energy. This objection is unfounded since the parent-subsidiary relationship does not eliminate the costs of a new issue, but merely transfers them to the parent. It would be unfair and discriminatory to subject parent shareholders to dilution while individual company shareholders are absolved from such dilution. Fair treatment must consider that, if the utility-subsidiary had gone to the capital markets directly, flotation costs would have been incurred.

IV. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RESULTS AND RECOMMENDATION.

A. To arrive at my final recommendation, I performed

(i) a DCF analysis on a group of investment-grade dividend-paying natural gas distribution utilities using Value Line's growth forecasts;

(ii) a DCF analysis on a group of investment-grade dividend-paying natural gas distribution utilities using analysts' growth forecasts;

(iii) a DCF analysis on a group of investment-grade dividend-paying combination gas and electric utilities using Value Line's growth forecasts;

(iv) a DCF analysis on a group of investment-grade dividend-paying combination gas and electric utilities using analysts' growth forecasts;

(v) a traditional CAPM using current market data;

(vi) an empirical approximation of the CAPM using current market data;

(vii) historical risk premium data from utility industry aggregate data, using the yield on long-term US Treasury bonds; and

(viii) allowed risk premium data from gas utility industry aggregate data, using the current yield on long-term US Treasury bonds.

Table 6 below summarizes the ROE estimates for Duke Energy Kentucky.

Table 6. Summary of ROE Estimates

Study	ROE
DCF Natural Gas Utility Value Line Growth	10.4%
DCF Natural Gas Utility Analyst Fcst Growth	9.8%
DCF Comb Elec Utilities Value Line Growth	10.0%
DCF Comb Elec Utilities Analyst Fcst Growth	9.2%
Capital Asset Pricing Model	9.7%
Empirical Capital Asset Pricing Model	10.1%
Historical Risk Premium	10.6%
Allowed Risk Premium	10.3%

The results range from 9.2% to 10.6%, with a midpoint of 9.9%. Based on all those results, and assuming the Commission approves the Company's requested weather adjustment clause, as I believe it should, I shall use 9.9% as my recommended ROE for Duke Energy Kentucky. If the Commission does not approve the Company's requested weather adjustment clause, I recommend a ROE in the upper half of the range identified.

I stress that no one individual method provides an exclusive foolproof formula for determining a fair return, but each method provides useful evidence so as to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is unsound when dealing with investor expectations. Moreover, the advantage of using several different approaches is that the results of each one can be used to check the others. Thus, the results shown in Table 6 above must be viewed as a whole rather than each as a stand-alone. It would be inappropriate to select any particular number from Table 6 and infer the cost of common equity from that number alone.

I also point out that I consider my recommended ROE conservative.

Q. DR. MORIN, WHY DO YOU CONSIDER YOUR RECOMMENDED ROE OF 9.9% CONSERVATIVE?

A. I consider my recommended return conservative for two reasons. The first reason is the small relative size of the Company's natural gas business. Duke Energy Kentucky's natural gas distribution business is small relative to that of its peer companies on the basis of revenues, capital base, and number of customers. Investment risk increases as company size diminishes, all else remaining constant. The size phenomenon is well documented in the finance literature, and is fully discussed in Chapter 6 of my book The New Regulatory Finance and is also fully discussed in the Duff & Phelps Valuation 2017 Yearbook which devotes two full chapters and two appendices documenting and quantifying the size effect. The gist of the literature is that small companies have very different returns than large ones and on average those returns have been higher. The greater risk of small stocks does not fully account for their higher returns over many historical periods. The average small stock premium is well in excess of that of the average stock, more than could be expected by risk differences alone, suggesting that the cost of equity for small stocks is considerably larger than for large capitalization stocks. In addition to earning the highest average rates of return, small stocks also have the highest volatility, as measured by the standard deviation of returns.

Q. CAN YOU COMMENT ON THE SECOND REASON?

A. Yes. The second reason is that he Company is very likely to raise very large sums of money in a rising interest rate environment over the next five years. The Company's capital expenditure program for its natural gas business will require approximately $160 million of financing over the next five years for new utility infrastructure investments. To place that number in proper perspective, the Company's common equity balance is approximately the same at $160 million, and its total capitalization base is approximately $310 million. In other words, the company is expected to spend an amount that equals its entire common equity ownership capital and to increase its total capitalization base over the next five years by almost 50%.

Because of the Company's very large construction program relative to its rate base and owners' capital (common equity balance) over the next few years, rate relief requirements and regulatory treatment uncertainty will increase regulatory risks as well. Generally, regulatory risks include approval risks, lags and delays, potential rate base exclusions, and potential disallowances. Continued regulatory support from the Commission will be required. Reviews of the economic and environmental aspects of new construction can consume as much as one year before approval or denial. Regulatory approval for financings required for new construction will also be required, injecting additional risks.

Q. DR. MORIN, WHAT IS YOUR FINAL CONCLUSION REGARDING DUKE ENERGY KENTUCKY'S ROE?

A. Based on the results of all my analyses, the application of my professional judgment, and the current circumstances in capital markets, it is my opinion that a just and reasonable and conservative ROE for Duke Energy Kentucky's natural gas utility operations in the State of Kentucky is 9.9% if the Company's requested weather normalization clause is approved. Otherwise, my recommended ROE would be in the upper portion of the 9.9% - 10.6%, range of results.

Q. IF CAPITAL MARKET CONDITIONS CHANGE SIGNIFICANTLY BETWEEN THE DATE OF FILING YOUR PREPARED TESTIMONY AND THE DATE ORAL TESTIMONY IS PRESENTED, WOULD THIS CAUSE YOU TO REVISE YOUR ESTIMATED COST OF EQUITY?

A. Yes. Interest rates and security prices do change over time, and risk premiums change also, although much more sluggishly. If substantial changes were to occur between the filing date and the time my oral testimony is presented, I will update my testimony accordingly.

Q. WERE ATTACHMENTS RAM-1 THROUGH RAM-11 AND APPENDICES A AND B PREPARED BY YOU AND UNDER YOUR DIRECTIONAND CONTROL?

A. Yes, they were.

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

A. Yes.

VERIFICATION

PROVINCE OF NOVA SCOTIA)
) **SS:**
COUNTY OF HALIFAX)

The undersigned, Dr. Roger A. Morin, Professor of Finance and a Principal in Utility Research International, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

Roger A. Morin

Dr. Roger A. Morin Affiant

Subscribed and sworn to before me by Dr. Roger A. Morin on this 7 day of AUGUST, 2018.

NOTARY PUBLIC

My Commission Expires: N/A

TRACEY D. KENNEDY
A Barrister of the Supreme
Court of Nova Scotia

RESUME OF ROGER A. MORIN

(Winter 2017)

NAME: Roger A. Morin

ADDRESS: 9 King Ave.
Jekyll Island, GA 31527, USA

132 Paddys Head Rd
Indian Harbour
Nova Scotia, Canada B3Z 3N8

TELEPHONE: (912) 635-2920 business office
(404) 229-2857 cellular
(902) 823-0000 summer office

E-MAIL ADDRESS: profmorin@mac.com

EMPLOYER 1980-2015: Georgia State University
Robinson College of Business
Atlanta, GA 30303

RANK: Emeritus Professor of Finance

HONORS: Distinguished Professor of Finance for Regulated Industry,
Director Center for the Study of Regulated Industry,
Robinson College of Business, Georgia State University.

EDUCATIONAL HISTORY

- Bachelor of Electrical Engineering, McGill University, Montreal, Canada, 1967.

- Master of Business Administration, McGill University, Montreal, Canada, 1969.

- PhD in Finance & Econometrics, Wharton School of Finance, University of Pennsylvania, 1976.

EMPLOYMENT HISTORY

- Lecturer, Wharton School of Finance, Univ. of Pennsylvania, 1972-3

- Assistant Professor, University of Montreal School of Business, 1973-1976.

- Associate Professor, University of Montreal School of Business, 1976-1979.

- Professor of Finance, Georgia State University, 1979-2011

- Professor of Finance for Regulated Industry and Director, Center for the Study of Regulated Industry, Robinson College of Business, Georgia State University, 1985-2009

- Visiting Professor of Finance, Amos Tuck School of Business, Dartmouth College, Hanover, N.H., 1986

- Emeritus Professor of Finance, Georgia State University, 2007-16

OTHER BUSINESS ASSOCIATIONS

- Communications Engineer, Bell Canada, 1962-1967.

- Member Board of Directors, Financial Research Institute of Canada, 1974-1980.

- Co-founder and Director Canadian Finance Research Foundation, 1977.

- Vice-President of Research, Garmaise-Thomson & Associates, Investment Management Consultants, 1980-1981.

- Member Board of Directors, Executive Visions Inc., 1985-2016

- Board of External Advisors, College of Business, Georgia State University, Member 1987-1991.

- Member Board of Directors, Hotel Equities Inc., 2009-2016

PROFESSIONAL CLIENTS

AGL Resources
AT & T Communications
Alagasco - Energen
Alaska Anchorage Municipal Light & Power
Alberta Power Ltd.
Allete
Alliant Energy
AmerenUE
American Water
Ameritech
Arkansas Western Gas
ATC Transmission
Baltimore Gas & Electric – Constellation Energy
Bangor Hydro-Electric
B.C. Telephone
B C GAS
Bell Canada
Bellcore
Bell South Corp.
Bruncor (New Brunswick Telephone)

Burlington-Northern
C & S Bank
California Pacific
Cajun Electric
Canadian Radio-Television & Telecomm. Commission
Canadian Utilities
Canadian Western Natural Gas
Cascade Natural Gas
Centel
Centra Gas
Central Illinois Light & Power Co
Central Telephone
Central & South West Corp.
CH Energy
Chattanooga Gas Company
Cincinnatti Gas & Electric
Cinergy Corp.
Citizens Utilities
City Gas of Florida
CN-CP Telecommunications
Commonwealth Telephone Co.
Columbia Gas System
Consolidated Edison
Consolidated Natural Gas
Constellation Energy
Delmarva Power & Light Co
Deerpath Group
Detroit Edison Company
Dayton Power & Light Co.
DPL Energy
Duke Energy Indiana
Duke Energy Kentucky
Duke Energy Ohio
DTE Energy
Edison International
Edmonton Power Company
Elizabethtown Gas Co.
Emera
Energen
Engraph Corporation
Entergy Corp.
Entergy Arkansas Inc.
Entergy Gulf States, Inc.
Entergy Louisiana, Inc.
Entergy Mississippi Power
Entergy New Orleans, Inc.

First Energy
Florida Water Association
Fortis
Garmaise-Thomson & Assoc., Investment Consultants
Gaz Metropolitain
General Public Utilities
Georgia Broadcasting Corp.
Georgia Power Company
GTE California - Verizon
GTE Northwest Inc. - Verizon
GTE Service Corp. - Verizon
GTE Southwest Incorporated - Verizon
Gulf Power Company
Havasu Water Inc.
Hawaiian Electric Company
Hawaiian Elec & Light Co
Heater Utilities – Aqua - America
Hope Gas Inc.
Hydro-Quebec
ICG Utilities
Illinois Commerce Commission
Island Telephone
ITC Holdings
Jersey Central Power & Light
Kansas Power & Light
KeySpan Energy
Maine Public Service
Manitoba Hydro
Maritime Telephone
Maui Electric Co.
Metropolitan Edison Co.
Minister of Natural Resources Province of Quebec
Minnesota Power & Light
Mississippi Power Company
Missouri Gas Energy
Mountain Bell
National Grid PLC
Nevada Power Company
New Brunswick Power
Newfoundland Power Inc. - Fortis Inc.
New Market Hydro
New Tel Enterprises Ltd.
New York Telephone Co.
NextEra Energy
Niagara Mohawk Power Corp
Norfolk-Southern

Northeast Utilities
Northern Telephone Ltd.
Northwestern Bell
Northwestern Utilities Ltd.
Nova Scotia Power
Nova Scotia Utility and Review Board
NUI Corp.
NV Energy
NYNEX
Oklahoma G & E
Ontario Telephone Service Commission
Orange & Rockland
PNM Resources
PPL Corp
Pacific Northwest Bell
People's Gas System Inc.
People's Natural Gas
Pennsylvania Electric Co.
Pepco Holdings
Potomac Electric Power Co.
Price Waterhouse
PSI Energy
Public Service Electric & Gas
Public Service of New Hampshire
Public Service of New Mexico
Puget Sound Energy
Quebec Telephone
Regie de l'Energie du Quebec
Rockland Electric
Rochester Telephone
SNL Center for Financial Execution
San Diego Gas & Electric
SaskPower
Sempra
Sierra Pacific Power Company
Source Gas
Southern Bell
Southern States Utilities
Southern Union Gas
South Central Bell
Sun City Water Company
TECO Energy
The Southern Company
Touche Ross and Company
TransEnergie
Trans-Quebec & Maritimes Pipeline

TXU Corp
US WEST Communications
Union Heat Light & Power
Utah Power & Light
Vermont Gas Systems Inc.
Wisconsin Power & Light

MANAGEMENT DEVELOPMENT AND PROFESSIONAL EXECUTIVE EDUCATION

- Canadian Institute of Marketing, Corporate Finance, 1971-73
- Hydro-Quebec, "Capital Budgeting Under Uncertainty," 1974-75
- Institute of Certified Public Accountants, Mergers & Acquisitions, 1975-78
- Investment Dealers Association of Canada, 1977-78
- Financial Research Foundation, bi-annual seminar, 1975-79
- Advanced Management Research (AMR), faculty member, 1977-80
- Financial Analysts Federation, Educational chapter: "Financial Futures Contracts" seminar
- Exnet Inc. a.k.a. The Management Exchange Inc., faculty member 1981-2008:

National Seminars: *Risk and Return on Capital Projects*
Cost of Capital for Regulated Utilities
Capital Allocation for Utilities
Alternative Regulatory Frameworks
Utility Directors' Workshop
Shareholder Value Creation for Utilities
Fundamentals of Utility Finance
Contemporary Issues in Utility Finance

- SNL Center for Financial Education. faculty member 2008-2016. National Seminars: *Essentials of Utility Finance*
- Georgia State University College of Business, Management Development Program, faculty member, 1981-1994.

EXPERT TESTIMONY & UTILITY CONSULTING AREAS OF EXPERTISE

Corporate Finance
Rate of Return
Capital Structure
Generic Cost of Capital
Costing Methodology
Depreciation
Flow-Through vs Normalization

Revenue Requirements Methodology
Utility Capital Expenditures Analysis
Risk Analysis
Capital Allocation
Divisional Cost of Capital, Unbundling
Incentive Regulation & Alternative Regulatory Plans
Shareholder Value Creation
Value-Based Management

REGULATORY BODIES

Alabama Public Service Commission
Alaska Regulatory Commission
Alberta Public Service Board
Arizona Corporation Commission
Arkansas Public Service Commission
British Columbia Board of Public Utilities
California Public Service Commission
Canadian Radio-Television & Telecommunications Comm.
City of New Orleans Council
Colorado Public Utilities Commission
Delaware Public Service Commission
District of Columbia Public Service Commission
Federal Communications Commission
Federal Energy Regulatory Commission
Florida Public Service Commission
Georgia Public Service Commission
Georgia Senate Committee on Regulated Industries
Hawaii Public Utilities Commission
Illinois Commerce Commission
Indiana Utility Regulatory Commission
Iowa Utilities Board
Kentucky Public Service Commission
Louisiana Public Service Commission
Maine Public Utilities Commission
Manitoba Board of Public Utilities
Maryland Public Service Commission
Michigan Public Service Commission
Minnesota Public Utilities Commission
Mississippi Public Service Commission
Missouri Public Service Commission
Montana Public Service Commission
National Energy Board of Canada
Nebraska Public Service Commission
Nevada Public Utilities Commission
New Brunswick Board of Public Commissioners
New Hampshire Public Utilities Commission

New Jersey Board of Public Utilities
New Mexico Public Regulation Commission
New Orleans City Council
New York Public Service Commission
Newfoundland Board of Commissioners of Public Utilities
North Carolina Utilities Commission
Nova Scotia Board of Public Utilities
Ohio Public Utilities Commission
Oklahoma Corporation Commission
Ontario Telephone Service Commission
Ontario Energy Board
Oregon Public Utility Service Commission
Pennsylvania Public Utility Commission
Quebec Regie de l'Energie
Quebec Telephone Service Commission
South Carolina Public Service Commission
South Dakota Public Utilities Commission
Tennessee Regulatory Authority
Texas Public Utility Commission
Utah Public Service Commission
Vermont Department of Public Services
Virginia State Corporation Commission
Washington Utilities & Transportation Commission
West Virginia Public Service Commission

SERVICE AS EXPERT WITNESS

Southern Bell, So. Carolina PSC, Docket #81-201C
Southern Bell, So. Carolina PSC, Docket #82-294C
Southern Bell, North Carolina PSC, Docket #P-55-816
Metropolitan Edison, Pennsylvania PUC, Docket #R-822249
Pennsylvania Electric, Pennsylvania PUC, Docket #R-822250
Georgia Power, Georgia PSC, Docket # 3270-U, 1981
Georgia Power, Georgia PSC, Docket # 3397-U, 1983
Georgia Power, Georgia PSC, Docket # 3673-U, 1987
Georgia Power, F.E.R.C., Docket # ER 80-326, 80-327
Georgia Power, F.E.R.C., Docket # ER 81-730, 80-731
Georgia Power, F.E.R.C., Docket # ER 85-730, 85-731
Bell Canada, CRTC 1987
Northern Telephone, Ontario PSC
GTE-Quebec Telephone, Quebec PSC, Docket 84-052B
Newtel., Nfld. Brd of Public Commission PU 11-87
CN-CP Telecommunications, CRTC
Quebec Northern Telephone, Quebec PSC
Edmonton Power Company, Alberta Public Service Board
Kansas Power & Light, F.E.R.C., Docket # ER 83-418

NYNEX, FCC generic cost of capital Docket #84-800
Bell South, FCC generic cost of capital Docket #84-800
American Water Works - Tennessee, Docket #7226
Burlington-Northern - Oklahoma State Board of Taxes
Georgia Power, Georgia PSC, Docket # 3549-U
GTE Service Corp., FCC Docket #84-200
Mississippi Power Co., Miss. PSC, Docket U-4761
Citizens Utilities, Ariz. Corp. Comm., Docket U2334-86020
Quebec Telephone, Quebec PSC, 1986, 1987, 1992
Newfoundland L & P, Nfld. Brd. Publ Comm. 1987, 1991
Northwestern Bell, Minnesota PSC, Docket P-421/CI-86-354
GTE Service Corp., FCC Docket #87-463
Anchorage Municipal Power & Light, Alaska PUC, 1988
New Brunswick Telephone, N.B. PUC, 1988
Trans-Quebec Maritime, Nat'l Energy Brd. of Cda, '88-92
Gulf Power Co., Florida PSC, Docket #88-1167-EI
Mountain States Bell, Montana PSC, #88-1.2
Mountain States Bell, Arizona CC, #E-1051-88-146
Georgia Power, Georgia PSC, Docket # 3840-U, l989
Rochester Telephone, New York PSC, Docket # 89-C-022
Noverco - Gaz Metro, Quebec Natural Gas PSC, #R-3164-89
GTE Northwest, Washington UTC, #U-89-3031
Orange & Rockland, New York PSC, Case 89-E-175
Central Illinois Light Company, ICC, Case 90-0127
Peoples Natural Gas, Pennsylvania PSC, Case
Gulf Power, Florida PSC, Case # 891345-EI
ICG Utilities, Manitoba BPU, Case 1989
New Tel Enterprises, CRTC, Docket #90-15
Peoples Gas Systems, Florida PSC
Jersey Central Pwr & Light, N.J. PUB, Case ER 89110912J
Alabama Gas Co., Alabama PSC, Case 890001
Trans-Quebec Maritime Pipeline, Cdn. Nat'l Energy Board
Mountain Bell, Utah PSC,
Mountain Bell, Colorado PUB
South Central Bell, Louisiana PS
Hope Gas, West Virginia PSC
Vermont Gas Systems, Vermont PSC
Alberta Power Ltd., Alberta PUB
Ohio Utilities Company, Ohio PSC
Georgia Power Company, Georgia PSC
Sun City Water Company
Havasu Water Inc.
Centra Gas (Manitoba) Co.
Central Telephone Co. Nevada
AGT Ltd., CRTC 1992
BC GAS, BCPUB 1992

California Water Association, California PUC 1992
Maritime Telephone 1993
BCE Enterprises, Bell Canada, 1993
Citizens Utilities Arizona gas division 1993
PSI Resources 1993-5
CILCORP gas division 1994
GTE Northwest Oregon 1993
Stentor Group 1994-5
Bell Canada 1994-1995
PSI Energy 1993, 1994, 1995, 1999
Cincinnati Gas & Electric 1994, 1996, 1999, 2004
Southern States Utilities, 1995
CILCO 1995, 1999, 2001
Commonwealth Telephone 1996
Edison International 1996, 1998
Citizens Utilities 1997
Stentor Companies 1997
Hydro-Quebec 1998
Entergy Gulf States Louisiana 1998, 1999, 2001, 2002, 2003
Detroit Edison, 1999, 2003
Entergy Gulf States, Texas, 2000, 2004
Hydro Quebec TransEnergie, 2001, 2004
Sierra Pacific Company, 2000, 2001, 2002, 2007, 2010
Nevada Power Company, 2001
Mid American Energy, 2001, 2002
Entergy Louisiana Inc. 2001, 2002, 2004
Mississippi Power Company, 2001, 2002, 2007
Oklahoma Gas & Electric Company, 2002 -2003
Public Service Electric & Gas, 2001, 2002
NUI Corp (Elizabethtown Gas Company), 2002
Jersey Central Power & Light, 2002
San Diego Gas & Electric, 2002, 2012, 2014
New Brunswick Power, 2002
Entergy New Orleans, 2002, 2008
Hydro-Quebec Distribution 2002
PSI Energy 2003
Fortis – Newfoundland Power & Light 2002
Emera – Nova Scotia Power 2004
Hydro-Quebec TransEnergie 2004
Hawaiian Electric 2004
Missouri Gas Energy 2004
AGL Resources 2004
Arkansas Western Gas 2004
Public Service of New Hampshire 2005
Hawaiian Electric Company 2005, 2008, 2009
Delmarva Power & Light Company 2005, 2009

Union Heat Power & Light 2005
Puget Sound Energy 2006, 2007, 2009
Cascade Natural Gas 2006
Entergy Arkansas 2006-7
Bangor Hydro 2006-7
Delmarva 2006, 2007, 2009
Potomac Electric Power Co. 2006, 2007, 2009
Duke Energy Ohio, 2007, 2008, 2009
Duke Energy Kentucky 2009
Consolidated Edison 2007 Docket 07-E-0523
Duke Energy Ohio Docket 07-589-GA-AIR
Hawaiian Electric Company Docket 05-0315
Sierra Pacific Power Docket ER07-1371-000
Public Service New Mexico Docket 06-00210-UT
Detroit Edison Docket U-15244
Potomac Electric Power Docket FC-1053
Delmarva, Delaware, Docket 09-414
Atlantic City Electric, New Jersey, Docket ER-09080664
Maui Electric Co, Hawaii, Docket 2009-0163, 2011
Niagara Mohawk, New York, Docket 10E-0050
Sierra Pacific Power Docket No. 10-06001
Gaz Metro, Regie de l'Energie (Quebec), Docket 2012 R-3752-2011
California Pacific Electric Company, LLC, California PUC, Docket A-12-02-014
Duke Energy Ohio, Ohio Case No. 11-XXXX-EL-SSO
San Diego Gas & Electric, FERC, 2012, 2014
San Diego Gas & Electric, California PUC, 2012, Docket A-12-04
Southern California Gas, California PUC, 2012, Docket A-12-04
Puget Sound Electric
Puget Sound Electric
Duke Energy of Ohio
Duke Energy of Kentucky
Duke Energy of Ohio
Dayton Power & Light
Missouri American Water
California Power Electric Company

PROFESSIONAL AND LEARNED SOCIETIES

- Engineering Institute of Canada, 1967-1972
- Canada Council Award, recipient 1971 and 1972
- Canadian Association Administrative Sciences, 1973-80
- American Association of Decision Sciences, 1974-1978
- American Finance Association, 1975-2002
- Financial Management Association, 1978-2002

ACTIVITIES IN PROFESSIONAL ASSOCIATIONS AND MEETINGS

- Chairman of meeting on "New Developments in Utility Cost of Capital", Southern Finance Association, Atlanta, Nov. 1982
- Chairman of meeting on "Public Utility Rate of Return", Southeastern Public Utility Conference, Atlanta, Oct. 1982
- Chairman of meeting on "Current Issues in Regulatory Finance", Financial Management Association, Atlanta, Oct. 1983
- Chairman of meeting on "Utility Cost of Capital", Financial Management Association, Toronto, Canada, Oct. 1984.
- Committee on New Product Development, FMA, 1985
- Discussant, "Tobin's Q Ratio", paper presented at Financial Management Association, New York, N.Y., Oct. 1986
- Guest speaker, "Utility Capital Structure: New Developments", National Society of Rate of Return Analysts 18th Financial Forum, Wash., D.C. Oct. 1986
- Opening address, "Capital Expenditures Analysis: Methodology vs Mythology," Bellcore Economic Analysis Conference, Naples Fl, 1988.
- Guest speaker, "Mythodology in Regulatory Finance", Society of Utility Rate of Return Analysts (SURFA), Annual Conference, Wash., D.C. February 2007.

PAPERS PRESENTED:

"An Empirical Study of Multi-Period Asset Pricing," annual meeting of Financial Management Assoc., Las Vegas Nevada, 1987.

"Utility Capital Expenditures Analysis: Net Present Value vs Revenue Requirements", annual meeting of Financial Management Assoc., Denver, Colorado, October 1985.

"Intervention Analysis and the Dynamics of Market Efficiency", annual meeting of Financial Management Assoc., San Francisco, Oct. 1982

"Intertemporal Market-Line Theory: An Empirical Study," annual meeting of Eastern Finance Assoc., Newport, R.I. 1981

"Option Writing for Financial Institutions: A Cost-Benefit Analysis", 1979 annual meeting Financial Research Foundation

"Free-lunch on the Toronto Stock Exchange", annual meeting of Financial Research Foundation of Canada, l978.

"Simulation System Computer Software SIMFIN", HP International Business Computer Users Group, London, 1975.

"Inflation Accounting: Implications for Financial Analysis." Institute of Certified Public Accountants Symposium, 1979.

OFFICES IN PROFESSIONAL ASSOCIATIONS

- President, International Hewlett-Packard Business Computers Users Group, 1977
- Chairman Program Committee, International HP Business Computers Users Group, London, England, 1975
- Program Coordinator, Canadian Assoc. of Administrative Sciences, 1976
- Member, New Product Development Committee, Financial Management Association, 1985-1986
- Reviewer: Journal of Financial Research
  Financial Management
  Financial Review
  Journal of Finance

PUBLICATIONS

"Risk Aversion Revisited", Journal of Finance, Sept. 1983

"Hedging Regulatory Lag with Financial Futures," Journal of Finance, May 1983. (with G. Gay, R. Kolb)

"The Effect of CWIP on Cost of Capital," Public Utilities Fortnightly, July 1986.

"The Effect of CWIP on Revenue Requirements" Public Utilities Fortnightly, August 1986.

"Intervention Analysis and the Dynamics of Market Efficiency," Time-Series Applications, New York: North Holland, 1983. (with K. El-Sheshai)

"Market-Line Theory and the Canadian Equity Market," Journal of Business Administration, Jan. l982, M. Brennan, editor

"Efficiency of Canadian Equity Markets," International Management Review, Feb. 1978.

"Intertemporal Market-Line Theory: An Empirical Test," Financial Review, Proceedings of the Eastern Finance Association, 1981.

BOOKS

Utilities' Cost of Capital, Public Utilities Reports Inc., Arlington, Va., 1984.

Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 2004

Driving Shareholder Value, McGraw-Hill, January 2001.

The New Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 2006.

MONOGRAPHS

Determining Cost of Capital for Regulated Industries, Public Utilities Reports, Inc., and The Management Exchange Inc., 1982 - 1993. (with V.L. Andrews)

Alternative Regulatory Frameworks, Public Utilities Reports, Inc., and The Management Exchange Inc., 1993. (with V.L. Andrews)

Risk and Return in Capital Projects, The Management Exchange Inc., 1980. (with B. Deschamps)

Utility Capital Expenditure Analysis, The Management Exchange Inc., 1983.

Regulation of Cable Television: An Econometric Planning Model, Quebec Department of Communications, 1978.

“An Economic & Financial Profile of the Canadian Cablevision Industry,” Canadian Radio-Television & Telecommunication Commission (CRTC), 1978.

Computer Users' Manual: Finance and Investment Programs, University of Montreal Press, 1974, revised 1978.

Fiber Optics Communications: Economic Characteristics, Quebec Department of Communications, 1978.

"Canadian Equity Market Inefficiencies", Capital Market Research Memorandum, Garmaise & Thomson Investment Consultants, 1979.

MISCELLANEOUS CONSULTING REPORTS

“Operational Risk Analysis: California Water Utilities,” Calif. Water Association, 1993.

"Cost of Capital Methodologies for Independent Telephone Systems", Ontario Telephone Service Commission, March 1989.

"The Effect of CWIP on Cost of Capital and Revenue Requirements", Georgia Power Company, 1985.

"Costing Methodology and the Effect of Alternate Depreciation and Costing Methods on Revenue Requirements and Utility Finances", Gaz Metropolitan Inc., 1985.

"Simulated Capital Structure of CN-CP Telecommunications: A Critique", CRTC, 1977.

"Telecommunications Cost Inquiry: Critique," CRTC, 1977.

"Social Rate of Discount in the Public Sector", CRTC Policy Statement, 1974.

"Technical Problems in Capital Projects Analysis", CRTC Policy Statement, 1974.

RESEARCH GRANTS

"Econometric Planning Model of the Cablevision Industry," International Institute of Quantitative Economics, CRTC.

"Application of the Averch-Johnson Model to Telecommunications Utilities," Canadian Radio-Television Commission. (CRTC)

"Economics of the Fiber Optics Industry", Quebec Dept. of Communications.

"Intervention Analysis and the Dynamics of Market Efficiency", Georgia State Univ. College of Business, 1981.

"Firm Size and Beta Stability", Georgia State University College of Business, 1982.

"Risk Aversion and the Demand for Risky Assets", Georgia State University College of Business, 1981.

Value Line's Natural Gas Distribution Group

	Company	Ticker
1	Atmos	ATO
2	Chesapeake Util	CPK
3	NJ Res	NJR
4	NISource	NI
5	Northwest Nat Gas	NWN
6	ONE Gas	OGS
7	So Jersey Ind	SJI
8	Southwest Gas	SWX
9	Spire	SR
10	UGI	UGI
11	WGL Holdings	WGL

Source: Value Line Investment Survey 7/18

Natural Gas Distribution Utilities
DCF Analysis Value Line Growth Rates

	Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Projected EPS Growth	(4) % Expected Divid Yield	(5) Cost of Equity	(6) ROE
ATO	1	Atmos	2.11	7.50	2.27	9.77	9.89
CPK	2	Chesapeake Util	1.75	8.50	1.90	10.40	10.50
NJR	3	NJ Res	2.38	9.50	2.61	12.11	12.24
NI	4	NISource	2.98	5.50	3.14	8.64	8.81
NWN	5	Northwest Nat Gas	2.94	4.30	3.07	7.37	7.53
OGS	6	ONE Gas	2.40	7.00	2.57	9.57	9.70
SJI	7	So Jersey Ind	3.31	9.50	3.62	13.12	13.32
SWX	8	Southwest Gas	2.63	9.00	2.87	11.87	12.02
SR	9	Spire	3.10	7.50	3.33	10.83	11.01
UGI	10	UGI	1.96	7.50	2.11	9.61	9.72
WGL	11	WGL Holdings	2.30	6.50	2.45	8.95	9.08
	13	**AVERAGE**	**2.53**	**7.48**	**2.72**	**10.20**	**10.35**

Notes:

16 Column 2: Zacks Investment Research July 2018
17 Column 3: Value Line Investment Reports July 2018
18 Column 4 = Column 2 times (1 + Column 3/100)
19 Column 5 = Column 4 + Column 3
20 Column 6 = Column 4/0.95 + Column 3

Note: Value Line growth rates not available
for NISource and Northwest Nat Gas.
Used Zacks analysts forecasts.

Natural Gas Distribution Utilities
DCF Analysis Analysts' Growth Forecasts

	Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Analysts' Growth Forecast	(4) % Expected Divid Yield	(5) Cost of Equity	(6) ROE
ATO	1	Atmos	2.11	7.00	2.26	9.26	9.38
CPK	2	Chesapeake Util	1.75	6.00	1.86	7.86	7.95
NJR	3	NJ Res	2.38	6.00	2.52	8.52	8.66
NI	4	NISource	2.98	5.50	3.14	8.64	8.81
NWN	5	Northwest Nat Gas	2.94	4.30	3.07	7.37	7.53
OGS	6	ONE Gas	2.40	5.70	2.54	8.24	8.37
SJI	7	So Jersey Ind	3.31	12.40	3.72	16.12	16.32
SWX	8	Southwest Gas	2.63	4.00	2.74	6.74	6.88
SR	9	Spire	3.10	4.00	3.22	7.22	7.39
UGI	10	UGI	1.96	8.00	2.12	10.12	10.23
WGL	11	WGL Holdings	2.30	13.20	2.60	15.80	15.94
	13	**AVERAGE**	**2.53**	**6.92**	**2.71**	**9.63**	**9.77**

Notes:

16 Column 2, 3: Zacks Investment Research July 2018

17 Column 4 = Column 2 times (1 + Column 3/100)

18 Column 5 = Column 4 + Column 3

19 Column 6 = Column 4/0.95 + Column 3

Note: Zacks growth rates not available for Southwest Gas. Used Value Line forecast.

Investment-Grade Dividend-Paying Combination Gas and Electric Utilities Covered in Value Line's Electric Utility

	(1) Company	(2) Ticker	(3)	(4) Note
1	Alliant Energy	LNT		
2	Ameren Corp.	AEE		
3	Avista Corp.	AVA	x	Acquired by HydroOne
4	Black Hills	BKH		Acquired SourceGas, completed 2/2016
5	CenterPoint Energy	CNP	x	Acquiring Vectren
6	Chesapeake Utilities	CPK		
7	CMS Energy Corp.	CMS		
8	Consol. Edison	ED		
9	Dominion Resources	D		Merged with Questar, completed 9/16
10	DTE Energy	DTE		
11	Duke Energy	DUK		Acquired Piedmont Natual Gas, completed 10/16
12	Empire Dist. Elec.	EDE	x	Acquired by Algonquin Power & Util
13	Entergy Corp	ETR	x	Nuclear exposure, corporate reorganization
14	Eversource Energy	ES		
15	Fortis	FTS		Owns several US combination gas & elec utilities
16	Exelon Corp	EXC		
17	MDU Resource	MDU	x	Reg. Revenues < 50%
18	MGE Energy	MGEE		
19	NorthWestern Corp.	NWE		
20	Pepco Holdings	POM	x	Merged with Exelon
21	PG&E Corp.	PCG	x	Suspended dividends
22	Public Serv. Enterprise	PEG		
23	SCANA Corp.	SCG	x	nuclear exposure
24	Unitil Corp	UTL	x	Market cap < $1B; not covered by VL
25	Sempra Energy	SRE		Acquisition of Oncor approved by regulators and boards of directors
26	TECO Energy	TE	x	Acquired by Emera
27	Vectren Corp.	VVC	x	Acquired by CenterPoint
28	WEC Energy Group	WEC		
29	Xcel Energy Inc.	XEL		

Source: Value Line Investment Survey 07/18

Second Proxy Group for Duke Energy Ky

	Company	Ticker
1	Alliant Energy	LNT
2	Ameren Corp.	AEE
3	Black Hills	BKH
4	Chesapeake Utilities	CPK
5	CMS Energy Corp.	CMS
6	Consol. Edison	ED
7	Dominion Resources	D
8	DTE Energy	DTE
9	Duke Energy	DUK
10	Eversource Energy	ES
11	Exelon Corp	EXC
12	Fortis	FTS
13	MGE Energy	MGEE
14	NorthWestern Corp.	NWE
15	Public Serv. Enterprise	PEG
16	Sempra	SRE
17	WEC Energy Group	WEC
18	Xcel Energy Inc.	XEL

Combination Elec & Gas Utilities
DCF Analysis Value Line Growth Rates

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Projected EPS Growth	(4) % Expected Divid Yield	(5) Cost of Equity	(6) ROE
1	Alliant Energy	3.12	6.50	3.32	9.82	10.00
2	Ameren Corp.	2.97	7.50	3.19	10.69	10.86
3	Black Hills	3.12	5.00	3.28	8.28	8.45
4	Chesapeake Utilities	1.75	8.50	1.90	10.40	10.50
5	CMS Energy Corp.	2.99	7.00	3.20	10.20	10.37
6	Consol. Edison	3.63	3.00	3.74	6.74	6.94
7	Dominion Resources	4.64	6.50	4.94	11.44	11.70
8	DTE Energy	3.29	7.00	3.52	10.52	10.71
9	Duke Energy	4.38	5.50	4.62	10.12	10.36
10	Eversource Energy	3.41	5.50	3.60	9.10	9.29
11	Exelon Corp	3.27	8.00	3.53	11.53	11.72
12	Fortis	4.08	8.00	4.41	12.41	12.64
13	MGE Energy	2.02	7.50	2.17	9.67	9.79
14	NorthWestern Corp.	3.77	3.50	3.90	7.40	7.61
15	Public Serv. Enterprise	3.45	4.00	3.59	7.59	7.78
16	Sempra	3.10	8.50	3.36	11.86	12.04
17	WEC Energy Group	3.39	7.00	3.63	10.63	10.82
18	Xcel Energy Inc.	3.31	5.50	3.49	8.99	9.18
20	**AVERAGE**	**3.32**	**6.33**	**3.52**	**9.86**	**10.04**

Notes:

23 Column 2: Zacks Investment Research July 2018

24 Column 3: Value Line Investment Reports July 2018

25 Column 4 = Column 2 times (1 + Column 3/100)

26 Column 5 = Column 4 + Column 3

27 Column 6 = Column 4/0.95 + Column 3

Combination Elec & Gas Utilities
DCF Analysis Analysts' Growth Forecasts

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Analysts' Growth Forecast	(4) % Expected Divid Yield	(5) Cost of Equity	(6) ROE
1	Alliant Energy	3.12	5.60	3.29	8.89	9.07
2	Ameren Corp.	2.97	6.50	3.16	9.66	9.83
3	Black Hills	3.12	4.30	3.25	7.55	7.73
4	Chesapeake Utilities	1.75	6.00	1.86	7.86	7.95
5	CMS Energy Corp.	2.99	6.40	3.18	9.58	9.75
6	Consol. Edison	3.63	4.00	3.78	7.78	7.97
7	Dominion Resources	4.64	6.10	4.92	11.02	11.28
8	DTE Energy	3.29	5.30	3.46	8.76	8.95
9	Duke Energy	4.38	4.60	4.58	9.18	9.42
10	Eversource Energy	3.41	5.80	3.61	9.41	9.60
11	Exelon Corp	3.27	5.70	3.46	9.16	9.34
12	Fortis	4.08	5.50	4.30	9.80	10.03
13	MGE Energy	2.02	7.50	2.17	9.67	9.79
14	NorthWestern Corp.	3.77	2.30	3.86	6.16	6.36
15	Public Serv. Enterprise	3.45	6.10	3.66	9.76	9.95
16	Sempra	3.10	8.50	3.36	11.86	12.04
17	WEC Energy Group	3.39	4.10	3.53	7.63	7.81
18	Xcel Energy Inc.	3.31	5.70	3.50	9.20	9.38
20	**AVERAGE**	**3.32**	**5.56**	**3.50**	**9.05**	**9.24**

Notes:

23 Column 2, 3: Zacks Investment Research July 2018

24 Column 4 = Column 2 times (1 + Column 3/100)

25 Column 5 = Column 4 + Column 3

26 Column 6 = Column 4/0.95 + Column 3

Natural Gas Utilities Beta Estimates

	(1)	(2)
Line No.	Company Name	Beta
1	Atmos	0.70
2	Chesapeake Util	0.70
3	NJ Res	0.80
4	NISource	0.60
5	Northwest Nat Gas	0.70
6	ONE Gas	0.70
7	So Jersey Ind	0.85
8	Southwest Gas	0.80
9	Spire	0.70
10	UGI	0.90
11	WGL Holdings	0.75
13	**AVERAGE**	**0.75**

15 Source: Value Line Reports July 2018

2018 Utility Industry Historical Risk Premium

Line No.	Year	(1) Long-Term Government Bond Yield	Long-Term Government Income Component Bond Yield	(2) 20 year Maturity Bond Value	(3) Gain/Loss	(4) Interest	(5) Bond Total Return	(6) S&P Utility Index Return	(7) Utility Equity Risk Premium Over Bond Returns	(8) Utility Equity Risk Premium Over Bond Return Income Component
1	1931	4.07%	3.33%	1,000.00						
2	1932	3.15%	3.69%	1,135.75	135.75	40.70	17.64%	-0.54%	-18.18%	-4.23%
3	1933	3.36%	3.12%	969.60	-30.40	31.50	0.11%	-21.87%	-21.98%	-24.99%
4	1934	2.93%	3.10%	1,064.73	64.73	33.60	9.83%	-20.41%	-30.24%	-23.51%
5	1935	2.76%	2.81%	1,025.99	25.99	29.30	5.53%	76.63%	71.10%	73.82%
6	1936	2.56%	2.77%	1,031.15	31.15	27.60	5.88%	20.69%	14.81%	17.92%
7	1937	2.73%	2.66%	973.93	-26.07	25.60	-0.05%	-37.04%	-36.99%	-39.70%
8	1938	2.52%	2.64%	1,032.83	32.83	27.30	6.01%	22.45%	16.44%	19.81%
9	1939	2.26%	2.40%	1,041.65	41.65	25.20	6.68%	11.26%	4.58%	8.86%
10	1940	1.94%	2.23%	1,052.84	52.84	22.60	7.54%	-17.15%	-24.69%	-19.38%
11	1941	2.04%	1.94%	983.64	-16.36	19.40	0.30%	-31.57%	-31.87%	-33.51%
12	1942	2.46%	2.46%	933.97	-66.03	20.40	-4.56%	15.39%	19.95%	12.93%
13	1943	2.48%	2.44%	996.86	-3.14	24.60	2.15%	46.07%	43.92%	43.63%
14	1944	2.46%	2.46%	1,003.14	3.14	24.80	2.79%	18.03%	15.24%	15.57%
15	1945	1.99%	2.34%	1,077.23	77.23	24.60	10.18%	53.33%	43.15%	50.99%
16	1946	2.12%	2.04%	978.90	-21.10	19.90	-0.12%	1.26%	1.38%	-0.78%
17	1947	2.43%	2.13%	951.13	-48.87	21.20	-2.77%	-13.16%	-10.39%	-15.29%
18	1948	2.37%	2.40%	1,009.51	9.51	24.30	3.38%	4.01%	0.63%	1.61%
19	1949	2.09%	2.25%	1,045.58	45.58	23.70	6.93%	31.39%	24.46%	29.14%
20	1950	2.24%	2.12%	975.93	-24.07	20.90	-0.32%	3.25%	3.57%	1.13%
21	1951	2.69%	2.38%	930.75	-69.25	22.40	-4.69%	18.63%	23.32%	16.25%
22	1952	2.79%	2.68%	984.75	-15.25	26.90	1.17%	19.25%	18.08%	16.57%
23	1953	2.74%	2.84%	1,007.66	7.66	27.90	3.56%	7.85%	4.29%	5.01%
24	1954	2.72%	2.79%	1,003.07	3.07	27.40	3.05%	24.72%	21.67%	21.93%
25	1955	2.95%	2.75%	965.44	-34.56	27.20	-0.74%	11.26%	12.00%	8.51%
26	1956	3.45%	2.99%	928.19	-71.81	29.50	-4.23%	5.06%	9.29%	2.07%
27	1957	3.23%	3.44%	1,032.23	32.23	34.50	6.67%	6.36%	-0.31%	2.92%
28	1958	3.82%	3.27%	918.01	-81.99	32.30	-4.97%	40.70%	45.67%	37.43%
29	1959	4.47%	4.01%	914.65	-85.35	38.20	-4.71%	7.49%	12.20%	3.48%
30	1960	3.80%	4.26%	1,093.27	93.27	44.70	13.80%	20.26%	6.46%	16.00%
31	1961	4.15%	3.83%	952.75	-47.25	38.00	-0.92%	29.33%	30.25%	25.50%
32	1962	3.95%	4.00%	1,027.48	27.48	41.50	6.90%	-2.44%	-9.34%	-6.44%
33	1963	4.17%	3.89%	970.35	-29.65	39.50	0.99%	12.36%	11.37%	8.47%
34	1964	4.23%	4.15%	991.96	-8.04	41.70	3.37%	15.91%	12.54%	11.76%
35	1965	4.50%	4.20%	964.64	-35.36	42.30	0.69%	4.67%	3.98%	0.47%
36	1966	4.55%	4.49%	993.48	-6.52	45.00	3.85%	-4.48%	-8.33%	-8.97%

2018 Utility Industry Historical Risk Premium

Line No.	Year	(1) Long-Term Government Bond Yield	Long-Term Government Income Component Bond Yield	(2) 20 year Maturity Bond Value	(3) Gain/Loss	(4) Interest	(5) Bond Total Return	(6) S&P Utility Index Return	(7) Utility Equity Risk Premium Over Bond Returns	(8) Utility Equity Risk Premium Over Bond Return Income Component
37	1967	5.56%	4.59%	879.01	-120.99	45.50	-7.55%	-0.63%	6.92%	-5.22%
38	1968	5.98%	5.50%	951.38	-48.62	55.60	0.70%	10.32%	9.62%	4.82%
39	1969	6.87%	5.96%	904.00	-96.00	59.80	-3.62%	-15.42%	-11.80%	-21.38%
40	1970	6.48%	6.74%	1,043.38	43.38	68.70	11.21%	16.56%	5.35%	9.82%
41	1971	5.97%	6.32%	1,059.09	59.09	64.80	12.39%	2.41%	-9.98%	-3.91%
42	1972	5.99%	5.87%	997.69	-2.31	59.70	5.74%	8.15%	2.41%	2.28%
43	1973	7.26%	6.51%	867.09	-132.91	59.90	-7.30%	-18.07%	-10.77%	-24.58%
44	1974	7.60%	7.27%	965.33	-34.67	72.60	3.79%	-21.55%	-25.34%	-28.82%
45	1975	8.05%	7.99%	955.63	-44.37	76.00	3.16%	44.49%	41.33%	36.50%
46	1976	7.21%	4.89%	1,088.25	88.25	80.50	16.87%	31.81%	14.94%	26.92%
47	1977	8.03%	7.14%	919.03	-80.97	72.10	-0.89%	8.64%	9.53%	1.50%
48	1978	8.98%	7.90%	912.47	-87.53	80.30	-0.72%	-3.71%	-2.99%	-11.61%
49	1979	10.12%	8.86%	902.99	-97.01	89.80	-0.72%	13.58%	14.30%	4.72%
50	1980	11.99%	9.97%	859.23	-140.77	101.20	-3.96%	15.08%	19.04%	5.11%
51	1981	13.34%	11.55%	906.45	-93.55	119.90	2.63%	11.74%	9.11%	0.19%
52	1982	10.95%	13.50%	1,192.38	192.38	133.40	32.58%	26.52%	-6.06%	13.02%
53	1983	11.97%	10.38%	923.12	-76.88	109.50	3.26%	20.01%	16.75%	9.63%
54	1984	11.70%	11.74%	1,020.70	20.70	119.70	14.04%	26.04%	12.00%	14.30%
55	1985	9.56%	11.25%	1,189.27	189.27	117.00	30.63%	33.05%	2.42%	21.80%
56	1986	7.89%	8.98%	1,166.63	166.63	95.60	26.22%	28.53%	2.31%	19.55%
57	1987	9.20%	7.92%	881.17	-118.83	78.90	-3.99%	-2.92%	1.07%	-10.84%
58	1988	9.19%	8.97%	1,000.91	0.91	92.00	9.29%	18.27%	8.98%	9.30%
59	1989	8.16%	8.10%	1,100.73	100.73	91.90	19.26%	47.80%	28.54%	39.70%
60	1990	8.44%	8.19%	973.17	-26.83	81.60	5.48%	-2.57%	-8.05%	-10.76%
61	1991	7.30%	8.22%	1,118.94	118.94	84.40	20.33%	14.61%	-5.72%	6.39%
62	1992	7.26%	7.26%	1,004.19	4.19	73.00	7.72%	8.10%	0.38%	0.84%
63	1993	6.54%	7.17%	1,079.70	79.70	72.60	15.23%	14.41%	-0.82%	7.24%
64	1994	7.99%	6.59%	856.40	-143.60	65.40	-7.82%	-7.94%	-0.12%	-14.53%
65	1995	6.03%	7.60%	1,225.98	225.98	79.90	30.59%	42.15%	11.56%	34.55%
66	1996	6.73%	6.18%	923.67	-76.33	60.30	-1.60%	3.14%	4.74%	-3.04%
67	1997	6.02%	6.64%	1,081.92	81.92	67.30	14.92%	24.69%	9.77%	18.05%
68	1998	5.42%	5.83%	1,072.71	72.71	60.20	13.29%	14.82%	1.53%	8.99%
69	1999	6.82%	5.57%	848.41	-151.59	54.20	-9.74%	-8.85%	0.89%	-14.42%
70	2000	5.58%	6.50%	1,148.30	148.30	68.20	21.65%	59.70%	38.05%	53.20%
71	2001	5.75%	5.53%	979.95	-20.05	55.80	3.57%	-30.41%	-33.98%	-35.94%
72	2002	4.84%	5.59%	1,115.77	115.77	57.50	17.33%	-30.04%	-47.37%	-35.63%

2018 Utility Industry Historical Risk Premium

		(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Year	Long-Term Government Bond Yield	Long-Term Government Income Component Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	S&P Utility Index Return	Utility Equity Risk Premium Over Bond Returns	Utility Equity Risk Premium Over Bond Return Income Component
73	2003	5.11%	4.80%	966.42	-33.58	48.40	1.48%	26.11%	24.63%	21.31%
74	2004	4.84%	5.02%	1,034.35	34.35	51.10	8.54%	24.22%	15.68%	19.20%
75	2005	4.61%	4.69%	1,029.84	29.84	48.40	7.82%	16.79%	8.97%	12.10%
76	2006	4.91%	4.68%	962.06	-37.94	46.10	0.82%	20.95%	20.13%	16.27%
77	2007	4.50%	4.86%	1,053.70	53.70	49.10	10.28%	19.36%	9.08%	14.50%
78	2008	3.03%	4.45%	1,219.28	219.28	45.00	26.43%	-28.99%	-55.42%	-33.44%
79	2009	4.58%	3.47%	798.39	-201.61	30.30	-17.13%	11.94%	29.07%	8.47%
80	2010	4.14%	4.25%	1,059.45	59.45	45.80	10.52%	5.49%	-5.03%	1.24%
81	2011	2.48%	3.81%	1,260.50	260.50	41.40	30.19%	19.88%	-10.31%	16.07%
82	2012	2.41%	2.40%	1,011.06	11.06	24.80	3.59%	1.99%	-1.60%	-0.41%
83	2013	3.67%	2.86%	822.57	-177.43	24.10	-15.33%	13.26%	28.59%	10.40%
84	2014	2.40%	3.12%	1,200.79	200.79	36.70	23.75%	28.61%	4.86%	25.49%
85	2015	2.60%	2.84%	968.96	-31.04	24.00	-0.70%	1.38%	2.08%	-1.46%
86	2016	2.60%	2.63%	1,000.00	0.00	26.00	2.60%	11.93%	9.33%	9.30%
87	2017	2.90%	2.89%	954.71	-45.29	26.00	-1.93%	12.11%	14.04%	9.22%
87	**Mean**								**5.6%**	**6.2%**

89 Source: Bloomberg Web site: Standard & Poors Utility Stock Index % Annual Change, Jan. to Dec.
90 Bond yields from Duff & Phelps Classic Yearbooks Table A-9 Long-Term Government Bonds Yields and Fed Reserve H-15 Data Release

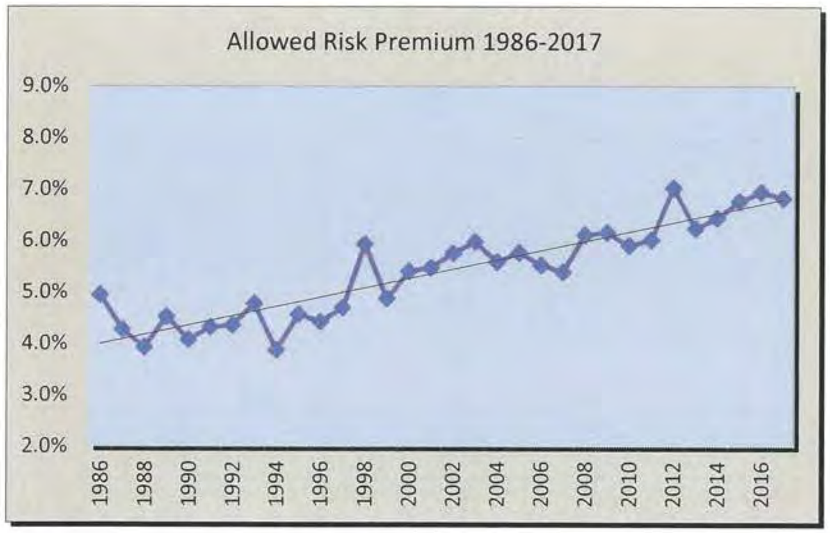
Equity Risk Premium - Treasury Bond

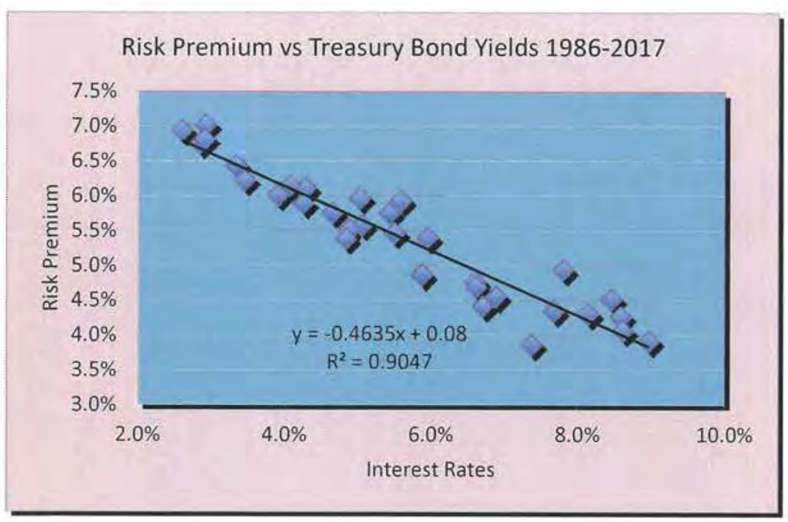
Line	Date	Treasury Bond Yield[1]	Authorized Gas Returns[2]	Indicated Risk Premium
		(1)	(2)	(3)
1	1986	7.80%	12.74%	4.9%
2	1987	8.58%	12.85%	4.3%
3	1988	8.96%	12.88%	3.9%
4	1989	8.45%	12.97%	4.5%
5	1990	8.61%	12.68%	4.1%
6	1991	8.14%	12.45%	4.3%
7	1992	7.67%	12.02%	4.4%
8	1993	6.60%	11.37%	4.8%
9	1994	7.37%	11.24%	3.9%
10	1995	6.88%	11.44%	4.6%
11	1996	6.70%	11.12%	4.4%
12	1997	6.61%	11.30%	4.7%
13	1998	5.58%	11.51%	5.9%
14	1999	5.87%	10.74%	4.9%
15	2000	5.94%	11.34%	5.4%
16	2001	5.49%	10.96%	5.5%
17	2002	5.42%	11.17%	5.8%
18	2003	5.02%	10.99%	6.0%
19	2004	5.05%	10.63%	5.6%
20	2005	4.65%	10.41%	5.8%
21	2006	4.88%	10.40%	5.5%
22	2007	4.83%	10.22%	5.4%
23	2008	4.28%	10.39%	6.1%
24	2009	4.07%	10.22%	6.2%
25	2010	4.25%	10.15%	5.9%
26	2011	3.91%	9.92%	6.0%
27	2012	2.92%	9.94%	7.0%
28	2013	3.45%	9.68%	6.2%
29	2014	3.34%	9.78%	6.4%
30	2015	2.84%	9.60%	6.8%
31	2016	2.60%	9.54%	6.9%
32	2017	2.90%	9.72%	6.8%
34	**Average**	**5.61%**	**11.01%**	**5.40%**

Sources:

1 Fed Reserve Board of Governors H.15 Release, 30-Yr Treasury ate

2 S&P Global Intelligence (Regulatory Research Associates)
Major Rate Case Decisions 1986-2017





IF YIELD =	4.20%
THEN RP =	6.05%
Ke =	10.25%

APPENDIX A
CAPM, EMPIRICAL CAPM

The Capital Asset Pricing Model (CAPM) is a fundamental paradigm of finance. Simply put, the fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that their:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is:

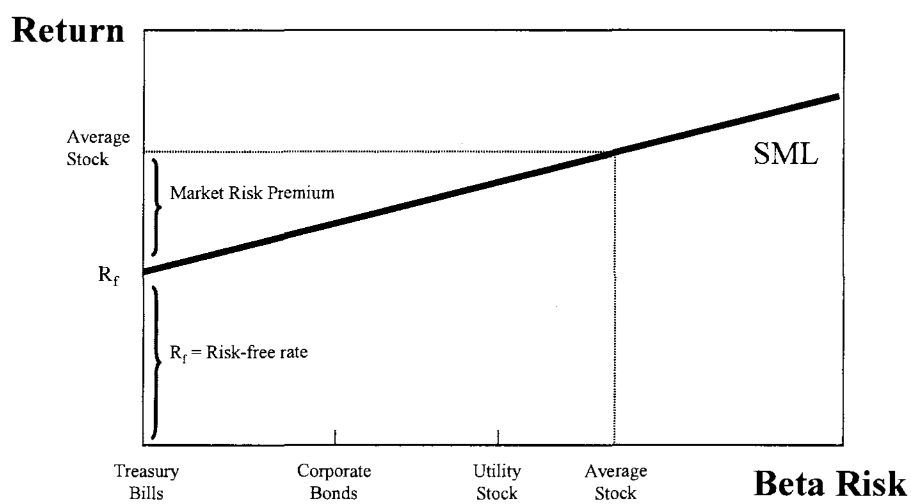
$$K = R_F + \beta(R_M - R_F) \tag{1}$$

Equation 1 is the CAPM expression which asserts that an investor expects to earn a return, K, that could be gained on a risk-free investment, R_F, plus a risk premium for assuming risk, proportional to the security's market risk, also known as beta, β, and the market risk premium, $(R_M - R_F)$, where R_M is the market return . The market risk premium $(R_M - R_F)$ can be abbreviated MRP so that the CAPM becomes:

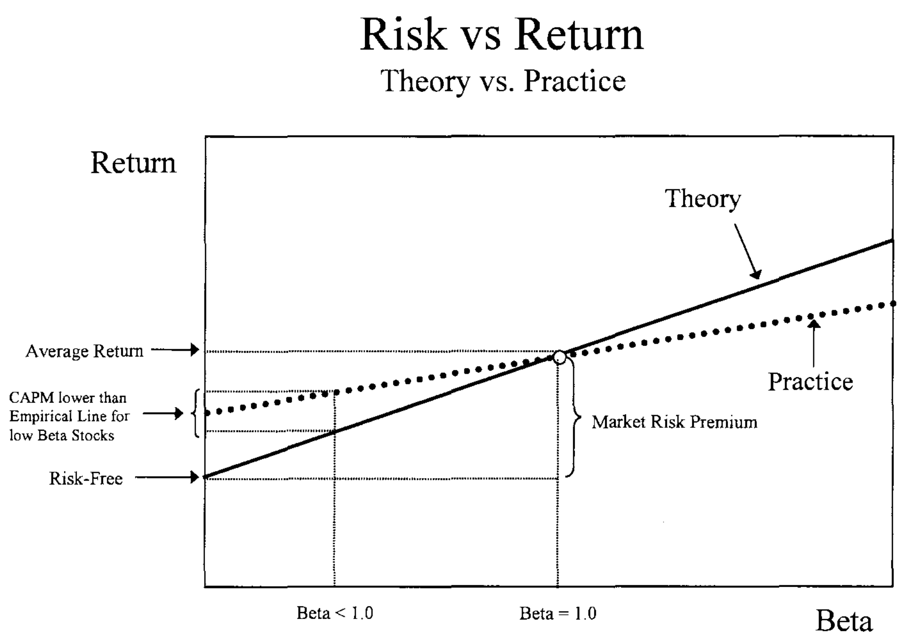
$$K = R_F + \beta \times MRP \tag{2}$$

The CAPM risk-return relationship is depicted in the figure below and is typically labeled as the Security Market Line (SML) by the investment community.

CAPM and Risk - Return
in Capital Markets



A myriad empirical tests of the CAPM have shown that the risk-return tradeoff is not as steeply sloped as that predicted by the CAPM, however. That is, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher returns and high-beta stocks tend to have lower risk returns than predicted by the CAPM. The difference between the CAPM and the type of relationship observed in the empirical studies is depicted in the figure below. This is one of the most widely known empirical findings of the finance literature. This extensive literature is summarized in Chapter 13 of Dr. Morin's book [The New Regulatory Finance, Public Utilities Report Inc., Arlington, VA, 2006].



A number of refinements and expanded versions of the original CAPM theory have been proposed to explain the empirical findings. These revised CAPMs typically produce a risk-return relationship that is flatter than the standard CAPM prediction. The following equation makes use of these empirical findings by flattening the slope of the risk-return relationship and increasing the intercept:

$$K = R_F + \alpha + \beta\ (MRP - \alpha) \qquad (3)$$

where α is the "alpha" of the risk-return line, a constant determined empirically, and the other symbols are defined as before. Alternatively, Equation 3 can be written as follows:

$$K = R_F + a\,MRP + (1\text{-}a)\,\beta\,MRP \qquad (4)$$

where a is a fraction to be determined empirically. Comparing Equations 3 and 4, it is easy to see that alpha equals 'a' times MRP, that is, $\alpha = a \times MRP$

Theoretical Underpinnings

The obvious question becomes what would produce a risk return relationship which is flatter than the CAPM prediction, or in other words, how do you explain the presence of "alpha" in the above equation. The exclusion of variables aside from beta would produce this result. Three such variables are noteworthy: dividend yield, skewness, and hedging potential.

The dividend yield effects stem from the differential taxation on corporate dividends and capital gains. The standard CAPM does not consider the regularity of dividends received by investors. Utilities generally maintain high dividend payout ratios relative to the market, and by ignoring dividend yield, the CAPM provides biased cost of capital estimates. To the extent that dividend income is taxed at a higher rate than capital gains, investors will require higher pre-tax returns in order to equalize the after-tax returns provided by high-yielding stocks (e.g. utility stocks) with those of low-yielding stocks. In other words, high-yielding stocks must offer investors higher pre-tax returns. Even if dividends and capital gains are undifferentiated for tax purposes, there is still a tax bias in favor of earnings retention (lower dividend payout), as capital gains taxes are paid only when gains are realized.

Empirical studies by Litzenberger and Ramaswamy (1979) and Litzenberger et al. (1980) find that security returns are positively related to dividend yield as well as to beta. These results are consistent with after-tax extensions of the CAPM developed by Breenan (1973) and Litzenberger and Ramaswamy (1979) and suggest that the relationship between return, beta, and dividend yield should be estimated and employed to calculate the cost of equity capital.

As far as skewness is concerned, investors are more concerned with losing money than with total variability of return. If risk is defined as the probability of loss, it appears more logical to measure risk as the probability of achieving a return which is below the expected return. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant. As shown by Kraus and Litzenberger (1976), expected return depends on both on a stock's systematic risk (beta) and the systematic skewness. Empirical studies by Kraus and Litzenberger (1976), Friend, Westerfield, and Granito (1978), and Morin (1981) found that, in addition to beta, skewness of returns has a significant negative relationship with security returns. This result is consistent with the skewness version of the CAPM developed by Rubinstein (1973) and Kraus and Litzenberger (1976).

This is particularly relevant for public utilities whose future profitability is constrained by the regulatory process on the upside and relatively unconstrained on the downside in the face of socio-political realities of public utility regulation. The process of regulation, by restricting the upward potential for returns and responding sluggishly on the downward side, may impart some asymmetry to the distribution of returns, and is more likely to result in utilities earning less, rather than more, than their cost of capital. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant.

As far as hedging potential is concerned, investors are exposed to another kind of risk, namely, the risk of unfavorable shifts in the investment opportunity set. Merton (1973) shows that investors will hold portfolios consisting of three funds: the risk-free asset, the market portfolio, and a portfolio whose returns are perfectly negatively correlated with the riskless asset so as to hedge against unforeseen changes in the future risk-free rate. The higher the degree of protection offered by an asset against unforeseen changes in interest rates, the lower the required return, and conversely. Merton argues that low beta assets, like utility stocks, offer little protection against changes in interest rates, and require higher returns than suggested by the standard CAPM.

Another explanation for the CAPM's inability to fully explain the process determining security returns involves the use of an inadequate or incomplete market index. Empirical studies to validate the CAPM invariably rely on some stock market index as a proxy for the true market portfolio. The exclusion of several asset categories from the definition of market index mis-specifies the CAPM and biases the results found using only stock market data. Kolbe and Read (1983) illustrate the biases in beta estimates which result from applying the CAPM to public utilities. Unfortunately, no comprehensive and easily accessible data exist for several classes of assets, such as mortgages and business investments, so that the exact relation between return and stock betas predicted by the CAPM does not exist. This suggests that the empirical relationship between returns and stock betas is best estimated empirically (ECAPM) rather than by relying on theoretical and elegant CAPM models expanded to include missing assets effects. In any event, stock betas may be highly correlated with the true beta measured with the true market index.

Yet another explanation for the CAPM's inability to fully explain the observed risk-return tradeoff involves the possibility of constraints on investor borrowing that run counter to the assumptions of the CAPM. In response to this inadequacy, several versions of the CAPM have been developed by researchers. One of these versions is the so-called zero-beta, or two-factor, CAPM which provides for a risk-free return in a market where borrowing and lending rates are divergent. If borrowing rates and lending rates differ, or there is no risk-free borrowing or lending, or there is risk-free lending but no risk-free borrowing, then the CAPM has the following form:

$$K = R_Z + \beta(R_m - R_F)$$

The model, christened the zero-beta model, is analogous to the standard CAPM, but with the return on a minimum risk portfolio which is unrelated to market returns, R_Z, replacing the risk-free rate, R_F. The model has been empirically tested by Black, Jensen, and Scholes (1972), who found a flatter than predicted CAPM, consistent with the model and other researchers' findings.

The zero-beta CAPM cannot be literally employed in cost of capital projections, since the zero-beta portfolio is a statistical construct difficult to replicate.

Empirical Evidence

A summary of the empirical evidence on the magnitude of alpha is provided in the table below.

Empirical Evidence on the Alpha Factor		
Author	**Range of alpha**	**Period relied**
Black (1993)	-3.6% to 3.6%	1931-1991
Black, Jensen and Scholes (1972)	-9.61% to 12.24%	1931-1965
Fama and McBeth (1972)	4.08% to 9.36%	1935-1968
Fama and French (1992)	10.08% to 13.56%	1941-1990
Litzenberger and Ramaswamy (1979)	5.32% to 8.17%	
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 5.04%	1926-1978
Pettengill, Sundaram and Mathur (1995)	4.6%	
Morin (1994)	2.0%	1926-1984
Harris, Marston, Mishra, and O'Brien (2003)	2.0%	1983-1998

Given the observed magnitude of alpha, the empirical evidence indicates that the risk-return relationship is flatter than that predicted by the CAPM. Typical of the empirical evidence is the findings cited in Morin (1989) over the period 1926-1984 indicating that the observed expected return on a security is related to its risk by the following equation:

$$K = .0829 + .0520\,\beta$$

Given that the risk-free rate over the estimation period was approximately 6 percent, this relationship implies that the intercept of the risk-return relationship is higher than the 6 percent risk-free rate, contrary to the CAPM's prediction. Given that the average return on an average risk stock exceeded the risk-free rate by about 8.0 percent in that period, that is, the market risk premium $(R_M - R_F) = 8$ percent, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2 percent, suggesting an alpha factor of 2 percent.

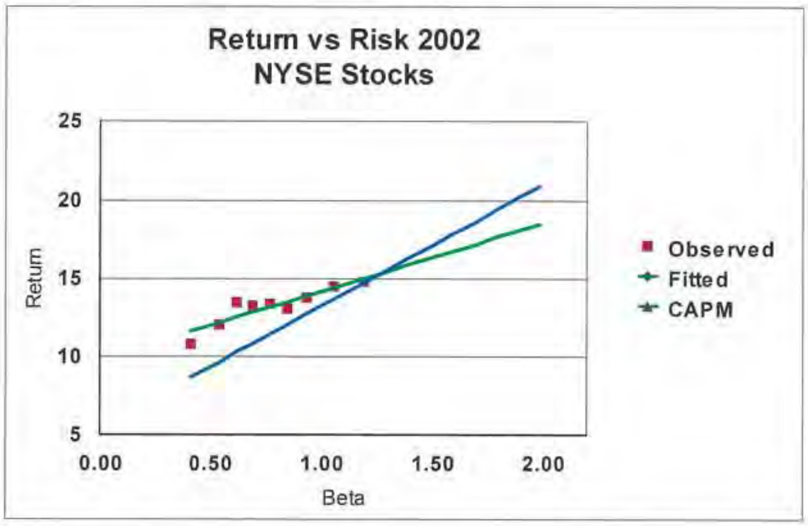
Most of the empirical studies cited in the above table utilize raw betas rather than Value Line adjusted betas because the latter were not available over most of the time periods covered in these studies. A study of the relationship between return and adjusted beta is reported on Table 6-7 in Ibbotson Associates Valuation Yearbook 2001. If we exclude the portfolio of very small cap stocks from the relationship due to significant size effects, the relationship between the arithmetic mean return and beta for the remaining portfolios is flatter than predicted and the intercept slightly higher than predicted by the CAPM, as shown on the graph below. It is noteworthy that the Ibbotson study relies on adjusted betas as stated on page 95 of the aforementioned study.

CAPM vs ECAPM

Another study by Morin in May 2002 provides empirical support for the ECAPM. All the stocks covered in the Value Line Investment Survey for Windows for which betas and returns data were available were retained for analysis. There were nearly 2000 such stocks. The expected return was measured as the total shareholder return ("TSR") reported by Value Line over the past ten years. The Value Line adjusted beta was also retrieved from the same data base. The nearly 2000 companies for which all data were available were ranked in ascending order of beta, from lowest to highest. In order to palliate measurement error, the nearly 2000 securities were grouped into ten portfolios of approximately 180 securities for each portfolio. The average returns and betas for each portfolio were as follows:

Portfolio #	Beta	Return
portfolio 1	0.41	10.87
portfolio 2	0.54	12.02
portfolio 3	0.62	13.50
portfolio 4	0.69	13.30
portfolio 5	0.77	13.39
portfolio 6	0.85	13.07
portfolio 7	0.94	13.75
portfolio 8	1.06	14.53
portfolio 9	1.19	14.78
portfolio 10	1.48	20.78

It is clear from the graph below that the observed relationship between DCF returns and Value Line adjusted betas is flatter than that predicted by the plain vanilla CAPM. The observed intercept is higher than the prevailing risk-free rate of 5.7 percent while the slope is less than equal to the market risk premium of 7.7 percent predicted by the plain vanilla CAPM for that period.



In an article published in Financial Management, Harris, Marston, Mishra, and O'Brien ("HMMO") estimate ex ante expected returns for S&P 500 companies over the period 1983-1998[1]. HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P 500 for each month from January 1983 to August 1998 by using the constant growth DCF model. They then investigate the relation between the risk premium (expected return over the 20-year U.S. Treasury Bond yield) estimates for each month to equity betas as of that same month (5-year raw betas).

The table below, drawn from HMMO Table 4, displays the average estimate prospective risk premium (Column 2) by industry and the corresponding beta estimate for that industry, both in raw form (Column 3) and adjusted form (Column 4). The latter were calculated with the traditional Value Line – Merrill Lynch – Bloomberg adjustment methodology by giving 1/3 weight of to a beta estimate of 1.00 and 2/3 weight to the raw beta estimate.

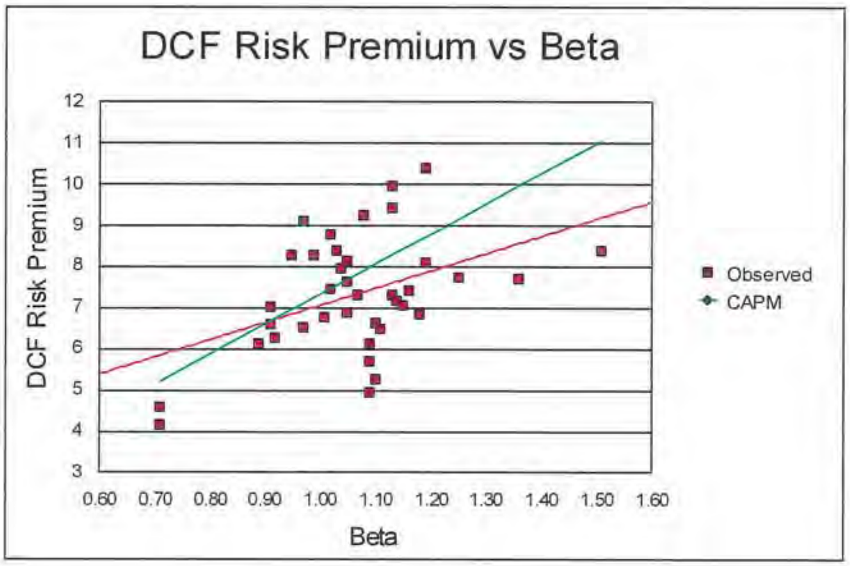
Table A-1 Risk Premium and Beta Estimates by Industry

	Industry	DCF Risk Premium	Raw Industry Beta	Adjusted Industry Beta
	(1)	(2)	(3)	(4)
1	Aero	6.63	1.15	1.10
2	Autos	5.29	1.15	1.10
3	Banks	7.16	1.21	1.14
4	Beer	6.60	0.87	0.91
5	BldMat	6.84	1.27	1.18
6	Books	7.64	1.07	1.05
7	Boxes	8.39	1.04	1.03
8	BusSv	8.15	1.07	1.05
9	Chems	6.49	1.16	1.11
10	Chips	8.11	1.28	1.19
11	Clths	7.74	1.37	1.25
12	Cnstr	7.70	1.54	1.36
13	Comps	9.42	1.19	1.13
14	Drugs	8.29	0.99	0.99
15	ElcEq	6.89	1.08	1.05
16	Energy	6.29	0.88	0.92
17	Fin	8.38	1.76	1.51
18	Food	7.02	0.86	0.91
19	Fun	9.98	1.19	1.13
20	Gold	4.59	0.57	0.71
21	Hlth	10.40	1.29	1.19
22	Hsld	6.77	1.02	1.01
23	Insur	7.46	1.03	1.02
24	LabEq	7.31	1.10	1.07
25	Mach	7.32	1.20	1.13
26	Meals	7.98	1.06	1.04
27	MedEq	8.80	1.03	1.02
28	Pap	6.14	1.13	1.09
29	PerSv	9.12	0.95	0.97
30	Retail	9.27	1.12	1.08
31	Rubber	7.06	1.22	1.15
32	Ships	1.95	0.95	0.97
33	Stee	4.96	1.13	1.09

[1] Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66.

34	Telc	6.12	0.83	0.89
35	Toys	7.42	1.24	1.16
36	Trans	5.70	1.14	1.09
37	Txtls	6.52	0.95	0.97
38	Util	4.15	0.57	0.71
39	Whlsl	8.29	0.92	0.95
	MEAN	**7.19**		

The observed statistical relationship between expected return and **adjusted beta** is shown in the graph below along with the CAPM prediction:



If the plain vanilla version of the CAPM is correct, then the intercept of the graph should be zero, recalling that the vertical axis represents returns in excess of the risk-free rate. Instead, the observed intercept is approximately 2 percent, that is approximately equal to 25 percent of the expected market risk premium of 7.2 percent shown at the bottom of Column 2 over the 1983-1998 period, as predicted by the ECAPM. The same is true for the slope of the graph. If the plain vanilla version of the CAPM is correct, then the slope of the relationship should equal the market risk premium of 7.2 percent. Instead, the observed slope of close to 5 percent is approximately equal to 75 percent of the expected market risk premium of 7.2 percent, as predicted by the ECAPM.

In short, the HMMO empirical findings are quite consistent with the predictions of the ECAPM.

Practical Implementation of the ECAPM

The empirical evidence reviewed above suggests that the expected return on a security is related to its risk by the following relationship:

$$K = R_F + \alpha + \beta\ (MRP - \alpha) \tag{5}$$

or, alternatively by the following equivalent relationship:

$$K = R_F + a\,MRP + (1\text{-}a)\,\beta\,MRP \tag{6}$$

The empirical findings support values of α from approximately 2 percent to 7 percent. If one is using the short-term U.S. Treasury Bills yield as a proxy for the risk-free rate, and given that utility stocks have lower than average betas, an alpha in the lower range of the empirical findings, 2 percent - 3 percent is reasonable, albeit conservative.

Using the long-term U.S. Treasury yield as a proxy for the risk-free rate, a lower alpha adjustment is indicated. This is because the use of the long-term U.S. Treasury yield as a proxy for the risk-free rate partially incorporates the desired effect of using the ECAPM[2]. An alpha in the range of 1 percent - 2 percent is therefore reasonable.

To illustrate, consider a utility with a beta of 0.80. The risk-free rate is 5 percent, the MRP is 7 percent, and the alpha factor is 2 percent. The cost of capital is determined as follows:

$$\begin{aligned} K &= R_F + \alpha + \beta\ (MRP - \alpha) \\ K &= 5\% + 2\% + 0.80(7\% - 2\%) \\ &= 11\% \end{aligned}$$

[2] The Security Market Line (SML) using the long-term risk-free rate has a higher intercept and a flatter slope than the SML using the short-term risk-free rate

A practical alternative is to rely on the second variation of the ECAPM:

$$K = R_F + a\,MRP + (1\text{-}a)\,\beta\,MRP$$

With an alpha of 2 percent, a MRP in the 6 percent - 8 percent range, the 'a" coefficient is 0.25, and the ECAPM becomes[3]:

$$K = R_F + 0.25\,MRP + 0.75\,\beta\,MRP$$

Returning to the numerical example, the utility's cost of capital is:

$$\begin{aligned} K &= 5\% + 0.25 \times 7\% + 0.75 \times 0.80 \times 7\% \\ &= 11\% \end{aligned}$$

For reasonable values of beta and the MRP, both renditions of the ECAPM produce results that are virtually identical[4].

---

[3] Recall that alpha equals 'a' times MRP, that is, alpha = a MRP, and therefore a = alpha/MRP. If alpha is 2 percent, then a = 0.25

[4] In the Morin (1994) study, the value of "a" was actually derived by systematically varying the constant "a" in equation 6 from 0 to 1 in steps of 0.05 and choosing that value of 'a' that minimized the mean square error between the observed relationship between return and beta:

$$K = 0.0829 + .0520\,\beta$$

The value of a that best explained the observed relationship was 0.25.

REFERENCES

Black, Fischer, "Beta and Return," The Journal of Portfolio Management, Fall 1993, 8-18.

Black, Fischer, Michael C. Jensen and Myron Scholes, "The Capital Asset Pricing Model: Some Empirical Tests, from Jensen, M. (ed.) Studies in the Theory of Capital Markets, Praeger, New York, 1972, 79-121.

Breenan, M. (1973) "Taxes, Market Valuation, and Corporate Financial Policy," National Tax Journal, 23, 417-427.

Fama, Eugene F. and James D. MacBeth, "Risk, Returns and Equilibrium: Empirical Tests," Journal of Political Economy, September 1972, pp. 607-636.

Fama, Eugene F. and Kenneth R. French, "The Cross-Section of Expected Stock Returns," Journal of Finance, Vol. 47, June 1992, pp. 427-465.

Friend, I., Westerfield, R., and Granito, M. (1978) "New Evidence on the Capital Asset Pricing Model, Journal of Finance, 23, 903-916.

Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "Ex Ante Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66.

Kraus, A. and Litzenberger, R.H. (1976) "Skewness Preference and the Valuation of Risk Assets, Journal of Finance, 31, 1085-99.

Litzenberger, R. H. and Ramaswamy, K. "The Effect of Personal Taxes and Dividends on Capital Asset Prices: Theory and Empirical Evidence." Journal of Financial Economics, June 1979, 163-196.

Litzenberger, R. H., Ramaswamy, K. and Sosin, H. (1980) "On the CAPM Approach to the Estimation of a Public Utility's Cost of Equity Capital, Journal of Finance, 35, May 1980, 369-83.

Merton, R.C. (1973) "An Intertemporal Capital Asset Pricing Model", Econometrica, 41, 867-887.

Morin, R.A. (1981) "Intertemporal Market-Line Theory: An Empirical Test," Financial Review, Proceedings of the Eastern Finance Association, 1981.

Morin, R.A. (1989) Arizona Corporation Commission, Rebuttal Testimony of Dr. Ra. Morin on behalf of US West Communications, Appendix B, 1989.

Pettengill, Glenn N., Sridhar Sundaram and Ike Mathur, "The Conditional Relation between Beta and Returns," Journal of Financial and Quantitative Analysis, Vol. 30, No. 1, March 1995, pp. 101-116.

Rubinstein, M.E. (1973) "A Mean-Variance Synthesis of Corporate Financial Theory, Journal of Financial Economics, March 1973, 167-82.

APPENDIX B

FLOTATION COST ALLOWANCE

To obtain the final cost of equity financing from the investors' expected rate of return, it is necessary to make allowance for underpricing, which is the sum of market pressure, costs of flotation, and underwriting fees associated with new issues. Allowance for market pressure should be made because large blocks of new stock may cause significant pressure on market prices even in stable markets. Allowance must also be made for company costs of flotation (including such items as printing, legal and accounting expenses) and for underwriting fees.

1. MAGNITUDE OF FLOTATION COSTS

According to empirical studies, underwriting costs and expenses average at least 4% of gross proceeds for utility stock offerings in the U.S. (See Logue & Jarrow: "Negotiations vs. Competitive Bidding in the Sale of Securities by Public Utilities", Financial Management, Fall 1978.) A study of 641 common stock issues by 95 electric utilities identified a flotation cost allowance of 5.0%. (See Borum & Malley: "Total Flotation Cost for Electric Company Equity Issues", Public Utilities Fortnightly, Feb. 20, 1986.)

Empirical studies suggest an allowance of 1% for market pressure in U.S. studies. Logue and Jarrow found that the absolute magnitude of the relative price decline due to market pressure was less than 1.5%. Bowyer and Yawitz examined 278 public utility stock issues and found an average market pressure of 0.72%. (See Bowyer & Yawitz, "The Effect of New Equity Issues on Utility Stock Prices", Public Utilities Fortnightly, May 22, 1980.)

Eckbo & Masulis ("Rights vs. Underwritten Stock Offerings: An Empirical Analysis", University of British Columbia, Working Paper No. 1208, Sept., 1987) found an average flotation cost of 4.175% for utility common stock offerings. Moreover, flotation costs increased progressively for smaller size issues. They also found that the relative price decline due to market pressure in the days surrounding the announcement amounted to slightly more than 1.5%. In a classic and monumental study published in the prestigious Journal of Financial Economics by a prominent scholar, a market pressure effect of 3.14% for industrial stock issues and 0.75% for utility common stock issues was found (see Smith, C.W., "Investment Banking and the Capital Acquisition Process," Journal of Financial Economics 15, 1986). Other studies of market pressure are reported in Logue ("On the Pricing of Unseasoned Equity Offerings, Journal of Financial and Quantitative Analysis, Jan. 1973), Pettway ("The Effects of New Equity Sales Upon Utility Share Prices," Public Utilities Fortnightly, May 10 1984), and Reilly and Hatfield ("Investor Experience with New Stock Issues," Financial Analysts' Journal, Sept.- Oct. 1969). In the Pettway study, the market pressure effect for a sample of 368 public utility equity sales was in the range of 2% to 3%. Adding the direct and indirect effects of utility common stock issues, the indicated total flotation cost allowance is above 5.0%, corroborating the results of earlier studies.

As shown in the table below, a comprehensive empirical study by Lee, Lochhead, Ritter, and Zhao, "The Costs of Raising Capital," Journal of Financial Research, Vol. XIX, NO. 1, Spring 1996, shows average direct flotation costs for equity offerings of 3.5% - 5% for stock issues between $60 and $500 million. Allowing for market pressure costs raises the flotation cost allowance to well above 5%.

FLOTATION COSTS: RAISING EXTERNAL CAPITAL
(Percent of Total Capital Raised)

Amount Raised in $ Millions	Average Flotation Cost: Common Stock	Average Flotation Cost: New Debt
$ 2 - 9.99	13.28%	4.39%
10 - 19.99	8.72	2.76
20 - 39.99	6.93	2.42
40 - 59.99	5.87	1.32
60 - 79.99	5.18	2.34
80 - 99.99	4.73	2.16
100 - 199.99	4.22	2.31
200 - 499.99	3.47	2.19
500 and Up	3.15	1.64

Note: Flotation costs for IPOs are about 17 percent of the value of common stock issued if the amount raised is less than $10 million and about 6 percent if more than $500 million is raised. Flotation costs are somewhat lower for utilities than others.

Source: Lee, Inmoo, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *The Journal of Financial Research,* Spring 1996.

As far as Canadian studies are concerned, Shutt, T. and Williams, H. "Going to Market: The Cost of IPOs in Canada and the United States," The Conference Board of Canada, June 2000, report a 5.8% weighted average cost for a sample of Toronto Stock Exchange issues. Kooli, M. and Suret, J.M., "How Cost Effective are Canadian IP Markets?" *Canadian Investment Review* 16, no. 4, Winter 2003, found flotation costs of 7.3% for equity issues of $100 million or more. These results are for IPOs only and would presumably be lower for seasoned equity issues.

Therefore, based on empirical studies, total flotation costs including market pressure amount to approximately 5% of gross proceeds. I have therefore assumed a 5% gross total flotation cost allowance in my cost of capital analyses.

2. APPLICATION OF THE FLOTATION COST ADJUSTMENT

The section below shows: 1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital, and 2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

Flotation costs are just as real as costs incurred to build utility plant. Fair regulatory treatment absolutely must permit the recovery of these costs. An analogy with bond issues is useful to understand the treatment of flotation costs in the case of common stocks.

In the case of a bond issue, flotation costs are not expensed but are rather amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. This is analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the company issues new debt capital in the future, until recovery is complete. In the case of common stock that has no finite life, flotation costs are not amortized. Therefore, the recovery of flotation cost requires an upward adjustment to the allowed return on equity. Roger A. Morin, Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994, provides numerical illustrations that show that even if a utility does not contemplate any additional common stock issues, a flotation cost adjustment is still permanently required. Examples there also demonstrate that the allowance applies to retained earnings as well as to the original capital.

From the standard DCF model, the investor's required return on equity capital is expressed as:

$$K = D_1/P_0 + g$$

If P_0 is regarded as the proceeds per share actually received by the company from which dividends and earnings will be generated, that is, P_o equals B_o, the book value per share, then the company's required return is:

$$r = D_1/B_o + g$$

Denoting the percentage flotation costs 'f', proceeds per share B_o are related to market price P_o as follows:

$$P - fP = B_o$$

$$P(1 - f) = B_o$$

Substituting the latter equation into the above expression for return on equity, we obtain:

$$r = D_1/P(1\text{-}f) + g$$

that is, the utility's required return adjusted for underpricing. For flotation costs of 5%, dividing the expected dividend yield by 0.95 will produce the adjusted cost of equity capital. For a dividend yield of 6% for example, the magnitude of the adjustment is 32 basis points: .06/.95 = .0632.

In deriving DCF estimates of fair return on equity, it is therefore necessary to apply a conservative after-tax allowance of 5% to the dividend yield component of equity cost.

Even if no further stock issues are contemplated, the flotation adjustment is still permanently required to keep shareholders whole. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years, even if no future financing is contemplated. This is demonstrated by the numerical example contained in pages 7-9 of this Appendix. Moreover, even if the stock price, hence the DCF estimate of equity return, fully reflected the lack of permanent allowance, the company always nets less than the market price. Only the net proceeds from an equity issue are used to add to the rate base on which the investor earns. A permanent allowance for flotation costs must be authorized in order to insure that in each year the investor earns the required return on the total amount of capital actually supplied.

The example shown on pages 7-9 shows the flotation cost adjustment process using illustrative, yet realistic, market data. The assumptions used in the computation are shown on page 7. The stock is selling in the market for \$25, investors expect the firm to pay a dividend of \$2.25 that will grow at a rate of 5% thereafter. The traditional DCF cost of equity is thus k = D/P + g = 2.25/25 + .05 = 14%. The firm sells one share stock, incurring a flotation cost of 5%. The traditional DCF cost of equity adjusted for flotation cost is thus ROE = D/P(1-f) + g = .09/.95 + .05 = 14.47%.

The initial book value (rate base) is the net proceeds from the stock issue, which are \$23.75, that is, the market price less the 5% flotation costs. The example demonstrates that only if the company is allowed to earn 14.47% on rate base will investors earn their cost of equity of 14%. On page 8, Column 1 shows the initial common stock account, Column 2 the cumulative retained earnings balance, starting at zero, and steadily increasing from the retention of earnings. Total equity in Column 3 is the sum of common stock capital and retained earnings. The stock price in Column 4 is obtained from the seminal DCF formula: $D_1/(k - g)$. Earnings per share in Column 6 are simply the allowed return of 14.47% times the total common equity base. Dividends start at \$2.25 and grow at 5% thereafter, which they must do if investors are to earn a 14% return. The dividend payout ratio remains constant, as per the assumption of the DCF model. All quantities, stock price, book value, earnings, and dividends grow at a 5% rate, as shown at the bottom of the relevant columns. Only if the company is allowed to earn 14.47% on equity do investors earn 14%. For example, if the company is allowed only 14%, the stock price drops from \$26.25 to \$26.13 in the second year, inflicting a loss on shareholders. This is shown on page 9. The growth rate drops from 5% to 4.53%. Thus, investors only earn 9% + 4.53% = 13.53% on their investment. It is noteworthy that the adjustment is always required each and every year, whether or not new stock issues are sold in the future, and that the allowed return on equity must be earned on total equity, including retained earnings, for investors to earn the cost of equity.

ASSUMPTIONS:

ISSUE PRICE =	$25.00
FLOTATION COST =	5.00%
DIVIDEND YIELD =	9.00%
GROWTH =	5.00%
EQUITY RETURN =	**14.00%**
(D/P + g)	
ALLOWED RETURN ON EQUITY =	**14.47%**
(D/P(1-f) + g)	

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET / BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
--------	--------	--------	--------	--------	--------	--------	--------	--------
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.438	$2.250	65.45%
2	$23.75	$1.188	$24.938	$26.250	1.0526	$3.609	$2.363	65.45%
3	$23.75	$2.434	$26.184	$27.563	1.0526	$3.790	$2.481	65.45%
4	$23.75	$3.744	$27.494	$28.941	1.0526	$3.979	$2.605	65.45%
5	$23.75	$5.118	$28.868	$30.388	1.0526	$4.178	$2.735	65.45%
6	$23.75	$6.562	$30.312	$31.907	1.0526	$4.387	$2.872	65.45%
7	$23.75	$8.077	$31.827	$33.502	1.0526	$4.607	$3.015	65.45%
8	$23.75	$9.669	$33.419	$35.178	1.0526	$4.837	$3.166	65.45%
9	$23.75	$11.340	$35.090	$36.936	1.0526	$5.079	$3.324	65.45%
10	$23.75	$13.094	$36.844	$38.783	1.0526	$5.333	$3.490	65.45%
			5.00%	5.00%		5.00%	5.00%	

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET/ BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
------	--------	--------	--------	--------	--------	--------	--------	--------
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.325	$2.250	67.67%
2	$23.75	$1.075	$24.825	$26.132	1.0526	$3.476	$2.352	67.67%
3	$23.75	$2.199	$25.949	$27.314	1.0526	$3.633	$2.458	67.67%
4	$23.75	$3.373	$27.123	$28.551	1.0526	$3.797	$2.570	67.67%
5	$23.75	$4.601	$28.351	$29.843	1.0526	$3.969	$2.686	67.67%
6	$23.75	$5.884	$29.634	$31.194	1.0526	$4.149	$2.807	67.67%
7	$23.75	$7.225	$30.975	$32.606	1.0526	$4.337	$2.935	67.67%
8	$23.75	$8.627	$32.377	$34.082	1.0526	$4.533	$3.067	67.67%
9	$23.75	$10.093	$33.843	$35.624	1.0526	$4.738	$3.206	67.67%
10	$23.75	$11.625	$35.375	$37.237	1.0526	$4.952	$3.351	67.67%
			4.53%	**4.53%**		**4.53%**	**4.53%**	

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 a Decoupling Mechanism; 3) Approval of New Tariffs; and 4) All Other Required Approvals, Waivers, and Relief.	)))))))	Case No. 2018-00261

DIRECT TESTIMONY OF

JOHN R. PANIZZA

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

August 31, 2018

TABLE OF CONTENTS

PAGE

I.	**INTRODUCTION AND PURPOSE**	**1**
II.	**SCHEDULES SPONSORED BY WITNESS**	**3**
III.	**TAX ACT**	**4**
IV.	**INCOME TAX EXPENSE**	**9**
V.	**PROPERTY TAX EXPENSE**	**10**
VI.	**CONCLUSION**	**11**

Attachment:

JRP-1 Amortization of EDITs

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. No.

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 Mr. Robert Beau Pratt with the property tax expense for the forecasted financial data. These expenses are based on projected property tax rates applied to the most recent valuations as approved by the Kentucky Department of Revenue (KDR), updated for projected additions, retirements, and additional depreciation.

I also provided Mr. Pratt with the income tax rates and the amortization of the investment tax credit for both the forecasted portion of the base period consisting of the six months ending November 30, 2018, and the forecasted test period ending March 31, 2020.

I reviewed Mr. Pratt's calculation of deferred income taxes for the base period and the forecasted period, I provided the amount of tax depreciation he used for this calculation, and I support the methodology he used for calculating deferred income taxes. I also provided Duke Energy Kentucky witness Mr. Pratt with the accumulated deferred investment tax credit balance for his use on Schedules J-1, J-1.1 and J-1.2.

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 brings comprehensive change to the individual, corporate and international tax law. The headline change to the corporate tax code is a reduction of the statutory corporate tax rate from 35 percent to 21 percent, but this reduction in rate is 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 ARE 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 will 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 excess ADITs resulting from the Tax Act.

Q. HAS DUKE ENERGY KENTUCKY INCORPORATED THE IMPACTS OF THE TAX ACT IN ITS RATES?

A. Duke Energy Kentucky's electric rates already reflect the full impact of the Tax Act. With this case, Duke Energy Kentucky is incorporating the impacts of the Tax Act into its natural gas base rates. In this case, the Company is adjusting its base rates to reflect the reduction in the federal corporate tax rate to 21 percent effective with new rates. In addition, the Company is also incorporating the credit related to the creation of EDITs stemming from the Tax Act. The Company is also proposing a pro-forma adjustment to reflect the lower corporate tax rate as it relates to the Company's Accelerated Service Replacement Program Rider (Rider ASRP) for the 2018 related revenue requirement. Duke Energy Kentucky witness Ms. Sarah Lawler discusses this adjustment in her testimony.

Q. PLEASE FURTHER DISCUSS THE CONCEPT OF ADITS.

A. Many timing differences exist between when income taxes are collected from customers in rates and when a company pays those taxes in cash to the IRS. Sometimes the taxed are paid sooner than when they are collected from customers (which creates a deferred tax asset on a company's books), and sometimes they are paid later (creating a deferred tax liability). Deferred taxes balances, therefore, result from book/tax timing differences between the recognition of income and expenses. All deferred tax balances, whether they are assets or liabilities, reverse over time and coverage to zero over the life of the underlying item giving rise to the "deferred" tax balance.

Q. HOW DOES THE TAX ACT ADDRESS THE ACCOUNTING TREATMENT OF EDITS?

A. Because of the passage of the Tax Act, the deferred tax assets and liabilities on the Company's books as of December 31, 2017, which were established at a rate of 35 percent, will be revalued at a rate of 21 percent creating EDITs.

Under the Tax Act, the protected EDIT reserve may be reduced with a corresponding reduction in the revenue that the utility collects from ratepayers no more rapidly than the reserve would be reduced under the Average Rate Assumption Method (ARAM).[1]

The property-related EDITs that are derived from tax versus book depreciation differences are considered "protected." These protected EDITs are subject to explicit normalization rules that utilities must follow. For this reason, the Company must use the ARAM[2] to amortize the balance of protected EDITs. Non-property-related EDITs and property-related EDITs that did not result from depreciation differences are considered "unprotected" and the Company is not required to follow strict normalization principles.

Q. HAS THE COMPANY QUANTIFIED THE BALANCE OF THE PROTECTED AND UNPROTECTED EXCESS ADITS FOR NATURAL GAS OPERATIONS?

A. Yes. The total projected balance of the EDITs for the Company's natural gas operations as of March 31, 2019 is as follows:

Protected EDITs (Federal)	$31,271,875
Unprotected EDITs (Federal)	$ 304,947
Unprotected EDITs (State)	$ 745,885
Total EDITs	$32,322,707

[1] AVERAGE RATE ASSUMPTION METHOD.—The average rate assumption method is the method under which the excess in the reserve for deferred taxes is reduced over the remaining lives of the property as used in its regulated books of account which gave rise to the reserve for deferred taxes. Under such method, during the time period in which the timing differences for the property reverse, the amount of the adjustment to the reserve for the deferred taxes is calculated by multiplying—(i) the ratio of the aggregate deferred taxes for the property to the aggregate timing differences for the property as of the beginning of the period in question, by (ii) the amount of the timing differences which reverse during such period.

The protected EDITs represent the remeasurement of property related deferred tax liabilities resulting from accelerated tax depreciation. The unprotected EDITs represent the remeasurement of all other property and non-property related deferred tax liabilities and assets. EDIT balances arising from the change in the Kentucky state income tax rate from 6% to 5% are all considered unprotected.

As I previously stated, the reversal of the EDITs related to accelerated depreciation should follow ARAM normalization accounting principles consistent with the Tax Act.

The amortization for these protected EDITs is dynamic and will change annually. The ARAM method, as set forth in the Tax Act, reduces the excess tax reserve over the remaining regulatory lives of the property that gave rise to the reserve for deferred taxes during the years in which the deferred tax reserve related to such property is reversing. The reversal of timing differences generally occurs when the amount of the tax depreciation is less than the amount of book depreciation for any given asset. Therefore, the ARAM calculation is calculated on each individual asset and is dependent on the remaining book and tax bases for that asset.

The unprotected EDITs are not required to be normalized in the same manner as the protected EDITs. Therefore, I have prepared an amortization schedule for this balance using a ten-year amortization period in compliance with this Commission's Order in the Company's recent electric base rate case, Case

No. 2017-00321, where the Commission directed Duke Energy Kentucky to amortize the balance over ten years.

Attachment JRP-1 contains an amortization schedule for the protected and unprotected EDITs. I provided this information to Mr. Pratt and Ms. Lawler for their use in factoring the impact of this reversal in the Company's revenue requirement.

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. Lawler for her use in calculating the revenue requirement. I also provided her with the amount of income tax expense for the base period and the forecasted test period, based on these income tax rates.

Q. WHY DID YOU USE THE STATUTORY KENTUCKY INCOME TAX RATE INSTEAD OF THE EFFECTIVE KENTUCKY INCOME TAX RATE TO CALCULATE DUKE ENERGY KENTUCKY'S INCOME TAX EXPENSE?

A. In my opinion, Duke Energy Kentucky should use the income tax rate that most accurately reflects the actual state income tax for its business on a stand-alone basis, which is the composite statutory rate of 5.0%. These are the proper tax rates to apply to Duke Energy Kentucky's natural gas business operations.

V. PROPERTY TAX EXPENSE

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 and Ohio with adjustments for anticipated property tax rate increases, additions including the power plant transfers, 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 2018 tax year so the Commission can determine whether to adjust Duke Energy Kentucky's property tax expense for the forecasted test period. The Ohio real property is assessed on a triennial basis, with the next re-assessment expected to occur in 2017. The Ohio personal property assessment for the 2017 tax year will be available in the fall of 2018.

VI. <u>CONCLUSION</u>

Q. WAS THE TAX INFORMATION YOU SUPPLIED FOR SCHEDULE B-6 AND SCHEDULES E-1 AND E-2, THE AMORTIZATION SCHEDULE CONTAINED IN ATTACHMENT JRP-1, 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.

VERIFICATION

STATE OF NORTH CAROLINA	)	
	)	**SS:**
COUNTY OF MECKLENBURG	)	

The undersigned, John R. Panizza, Director, Tax Operations, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

John R. Panizza

John R. Panizza Affiant

Subscribed and sworn to before me by John R. Panizza on this 14th day of August, 2018.

Natalie W Polk
NOTARY PUBLIC
Cabarrus County, NC
My Commission Expires 4-29-2023

Natalie W. Polk

NOTARY PUBLIC

My Commission Expires: 4-29-2023

AMORTIZATION OF EDITS

		Total	Federal	State
Protected ADITs		31,411,585	31,411,585	0
Year 1 Estimated ARAM		1.7791%	1.7791%	
		558,842	558,842	
Amortization 9 months ended 12/31/19	9/12	419,131	419,131	
Moved to Unprotected	3/12	139,710	139,710	
Remaining Amortization		30,852,743	30,852,743	
Year 2 Estimated ARAM		1.7674%	1.7674%	
Amortization 3 months ended 03/31/20	3/12	136,326	136,326	
Total TY Amortization Protected Excess ADITs		555,458	555,458	
Unprotected Excess ADITs		911,122	165,237	745,885
Moved from Protected		139,710	139,710	
Total Unprotected ADITs		1,050,832	304,947	745,885
No. of Years		10	10	10
Total TY Amortization Unprotected Excess ADITs		105,083	30,495	74,589
Total Amortization of Excess ADITs in Test Year		660,541	585,952	74,589

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 a Decoupling Mechanism; 3) Approval of New Tariffs; and 4) All Other Required Approvals, Waivers, and Relief.	)))))))	Case No. 2018-00261

DIRECT TESTIMONY OF

BENJAMIN WALTER BOHDAN PASSTY, PH.D.

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

August 31, 2018

TABLE OF CONTENTS

		PAGE
I.	INTRODUCTION AND PURPOSE	1
II.	LOAD FORECAST	3
III.	DEGREE DAY DATA USED IN THE FORECAST	7
IV.	WEATHER NORMALIZATION ADJUSTMENT	12
V.	FILING REQUIREMENTS AND INFORMATION SPONSORED BY WITNESS	14
VI.	CONCLUSION	15

Attachments:

BWP-1 – Duke Kentucky Gas Sales History and Forecast

BWP-2 – Comparison of Weather Normal Forecasts to Actual Heating Degree Day forecasts, Annual, 2013-2016; Annual Degree Days, 1981-2015 Heating and Cooling

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 SENIOR 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. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE ANY OTHER REGULATORY AGENCIES?

A. Yes. I have presented testimony on several occasions before the Indiana Utility Regulatory Commission.

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 2018 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 Mr. Robert "Beau" Pratt and Mr. Bruce Sailers for their use in preparing additional testimony.

II. LOAD FORECAST

Q. DID YOU PREPARE THE COMPANY'S GAS VOLUME FORECAST?

A. Yes, I did.

Q. HOW IS DUKE ENERGY KENTUCKY'S GAS VOLUME FORECAST DEVELOPED?

A. Generally speaking, the Gas Volume Forecast is developed in four steps: first, a service area economic forecast is obtained; second, a customer forecast is obtained; next, an energy forecast is prepared; and finally, using the energy forecast, summer and winter peak demand forecasts are developed.

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

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

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

Q. HOW IS THE CUSTOMER FORECAST OBTAINED?

A. The customer forecast is delivered to me by Duke Energy's Natural Gas Residential and Commercial Sales group that calculates the forecast.

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 factors 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 and real energy prices. For the commercial sector, the key factors include total employment and real energy prices. The governmental sector model includes government employment, as well as energy prices. In the industrial sector, the key factors include 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 always statistically significant.

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

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

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

A. While many economic and weather variables are relevant to the entire greater Cincinnati area, the Duke Energy Kentucky sales forecast is developed by maintaining specific forecasting models for sales only to Duke Energy Kentucky customers in the residential, commercial, industrial, government or OPA.

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

A. The Company may adjust the forecast for anticipated increases in load due to a major new customer or a significant expansion at a current customer's site.

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 many too few years 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, but with so few data points, it is impossible to reject the statistical hypothesis that the expected errors are equal.

IV. WEATHER NORMALIZATION ADJUSTMENT

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSAL TO IMPLEMENT A WEATHER NORMALIZATION ADJUSTMENT MECHANISM.

A. Duke Energy Kentucky Witness Mr. Bruce Sailers describes the weather normalization adjustment (WNA) in detail in his testimony. In short, the Company proposes a normalized level of revenues and expenses for a test year, 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 calculation of normal weather conditions to eliminate the impact of weather-related fluctuations in the test period. Were this not accounted-for, rates might be set too high or too low. Specifically, test year weather related sales volumes reflect normal levels of heating degree days. As I previously described, 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 customer's bills to fluctuate significantly from

However, for the 2018 Load Forecast there were no adjustments for new customer loads or expansion at a current customer's site.

Q. IS DUKE ENERGY KENTUCKY'S LOAD FORECASTING METHODOLOGY SIMILAR TO THAT EMPLOYED AT THE TIME OF THE COMPANY'S LAST BASE NATURAL GAS 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. One important difference is the use of a rolling thirty-year weather normalization period, which I will discuss below.

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. These commonly used factors include: weather data, population, income forecasts, industrial production or output measures, employment, and price information. In addition, price forecasts for alternate fuels including natural gas and fuel oil are 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 gas sales forecast and five-year growth rates forecast. The projected annualized rate of growth in total retail sales for the five-year period 2018 to 2023 is 0.6% per year.

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

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

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

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

A. Yes. NOAA is responsible for monitoring climate conditions in the United States. Additional information about NOAA is available at their web site at www.noaa.gov. The standard time period prescribed by the United Nations World Meteorological Organization for measuring climate conditions is 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 next 30-year normal weather period will be released several years from now and will encompass the period spanning 1991-2020.

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 at the time of the forecast.

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

A. The years 1986-2015 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.

Q. WHAT HAS BEEN THE LONG-TERM TREND IN HDD AND CDD FOR COVINGTON, KENTUCKY?

A. With respect to cooling, the years 1986-2015 appear to hint at a slight upward trend. Basic econometric analysis fails to confirm that this trend is caused by anything other than random variation. The slight decreasing trend in heating degree days over the same period—while visually hinted at—also fails to hold up under statistical testing. 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. Because 2007 was a particularly warm year, the last ten years suggest a slight cooling of summer weather; once again, statistical work cannot distinguish any trend from random 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 LAST TEN YEARS FOR COVINGTON, KENTUCKY, COMPARE TO 30-YEAR NORMALS?

A. See Attachment BWP-2 for a graph comparing the annual degree days in heating/cooling 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 more extreme weather than the thirty-year normal. Annual weather is much more variable than the degree to which the various forecasts vary from each other. This is also the case in two out of four recent years for heating degree days.

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 month to month and can result in 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 WNA mechanism will adjust the volumetric component of base delivery charges on customer bills to reflect the impact of weather conditions that diverge from what is expected.

Q. PLEASE EXPLAIN HOW THE NORMALIZATION ADJUSTMENT IS CALCULATED.

A. Again, Mr. Sailers describes this in greater detail in his direct testimony. In summary, 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) that I calculated for purposes of this proceeding.

Q. PLEASE EXPLAIN YOUR CALCULATION OF THE BL and HSF FOR THE MECHANISM.

A. This calculation depends on estimating a linear model that predicts how volume sales vary with weather. The model is exposed to data on monthly observations of sales billed to customers and weather measured in degree days; the factors that Mr. Sailers presents were based on forty-one monthly observations from January 2015 through May 2018. Rate classes are computed separately. The weather is calculated based on the meter read cycle for the appropriate class of customers rather than the calendar month, so as to match up with the time period of the sales.

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. Mr. Sailers also requested a "Correlation Factor"—sometimes referred to as the "R-Squared"—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 Mr. Pratt with the gas Mcf and electric kWh sales for the forecasted portion of the base period, consisting of the twelve months ending November 30, 2018, and the forecasted test period, consisting of the twelve months ending March 31, 2020.

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 MR. PRATT AND ATTACHMENTS BWP-1 THROUGH BWP-5 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

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

A. Yes.

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

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

Benjamin W B Passty
Benjamin Walter Bohdan Passty Affiant

Subscribed and sworn to before me by Benjamin Walter Bohdan Passty on this 9th day of August, 2018.

Deborah E Hampton
NOTARY PUBLIC

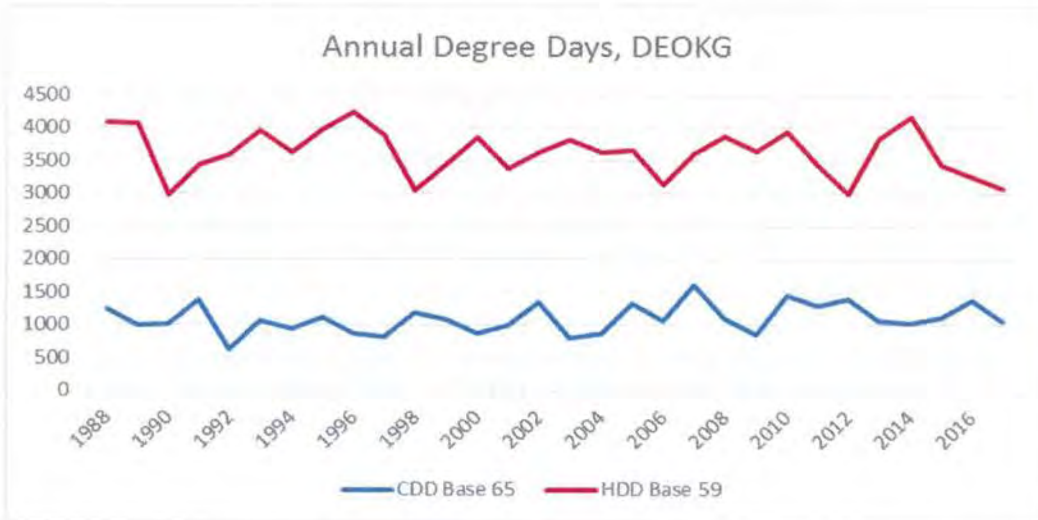
DEBORAH E HAMPTON
Notary Public
Mecklenburg Co., North Carolina
My Commission Expires Aug. 16, 2021

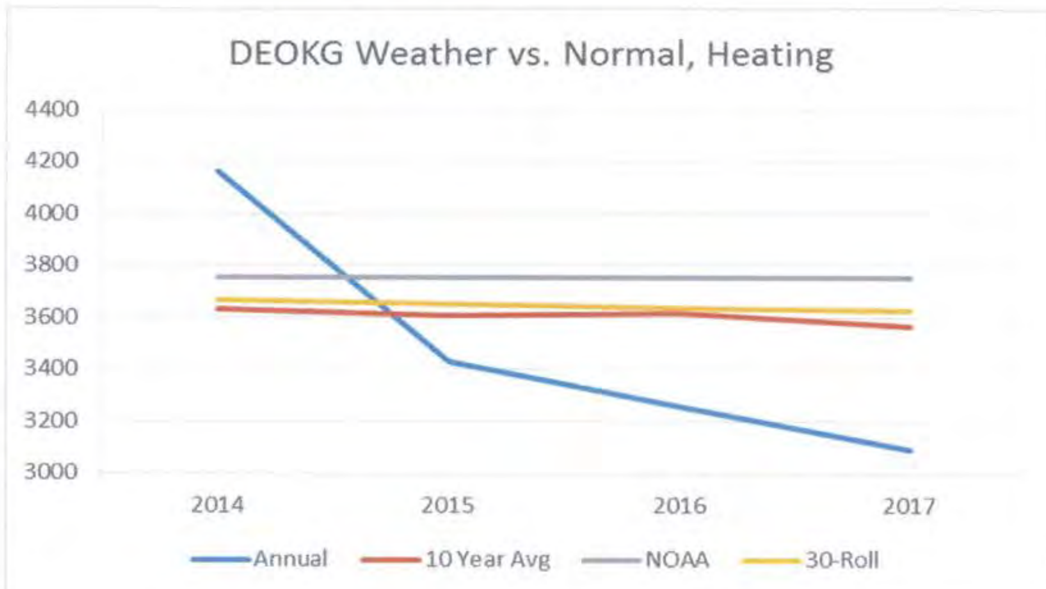
My Commission Expires: August 16, 2021

DUKE ENERGY KENTUCKY
SERVICE AREA ENERGY FORECAST (Volume in MCF) (a)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2							(1+2+3+4+5+6)
	YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET-HWY LIGHTING/ID /OEU	OPA	OTHER	TOTAL CONSUMPTION
-5	2013	6,178,997	3,382,935	1,631,370	1,513,013	572,089		13,278,404
-4	2014	6,240,687	3,643,573	1,769,232	1,339,151	593,573		13,586,216
-3	2015	6,152,682	3,452,335	1,929,493	1,343,566	574,342		13,452,418
-2	2016	5,594,915	3,339,845	1,805,038	1,515,518	527,900		12,783,216
-1	2017	5,770,315	3,352,552	1,815,524	1,553,210	526,874		13,018,475
0	2018	5,737,782	3,439,100	1,884,369	1,484,537	521,378		13,067,165
1	2019	5,805,630	3,464,146	1,911,401	1,484,490	521,105		13,186,772
2	2020	5,882,108	3,484,953	1,945,278	1,484,708	525,080		13,322,128
3	2021	5,914,518	3,464,051	1,981,060	1,485,196	528,800		13,373,625
4	2022	5,903,376	3,454,462	2,023,977	1,485,777	537,617		13,405,208
5	2023	5,895,332	3,457,955	2,075,256	1,486,295	544,336		13,459,174

(a) Figures in years -5 through -1 are weather-normalized


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
CDD Base 65
HDD Base 59


DEOKG Weather vs. Normal, Heating
4400
4200
4000
3800
3600
3400
3200
3000
2014
2015
2016
2017
Annual
10 Year Avg
NOAA
30-Roll

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 a Decoupling Mechanism; 3) Approval of New Tariffs; and 4) All Other Required Approvals, Waivers, and Relief.	)))))))	Case No. 2018-00261

DIRECT TESTIMONY OF

ROBERT H. "BEAU" PRATT

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

August 31, 2018

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND PURPOSE 1

II. DUKE ENERGY KENTUCKY'S FINANCIAL OBJECTIVES 4

III. CREDIT QUALITY & CREDIT RATINGS 5

IV. CAPITAL STRUCTURE AND COST OF CAPITAL 9

V. DUKE ENERGY KENTUCKY'S CAPITAL REQUIREMENTS 13

VI. THE BUDGETING AND FORECASTING PROCESS 14

VII. METHODOLOGY FOR THE FORECASTED DATA 17

A. INCOME STATEMENT 17
B. BALANCE SHEET STATEMENT 23
C. CASH FLOW STATEMENT 24

VIII. REASONABLENESS OF THE FORECASTED TEST PERIOD DATA 24

IX. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS 25

X. CONCLUSION 35

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert H. "Beau" Pratt, 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, Regional Financial Forecasting. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

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

A. I graduated from the University of North Carolina at Chapel Hill in 2006 with a Bachelor of Science in Business Administration. I started my employment with Progress Energy, Inc. (Progress Energy) in 2006 as a financial specialist in the Treasury and Enterprise Risk Management Department, performing risk reporting and analytics supporting utility and non-utility fuel procurement and trading operations. Subsequently, I held various positions at Progress Energy, including Coal Procurement Agent within the Fuels and Power Optimization Department and Continuous Business Excellence Leader within the Corporate Planning Department. After the merger with Duke Energy was announced in 2011, I performed a dual financial support role within the Investor Relations Department and Fuels and Power Optimization Department. After the merger between Progress Energy and Duke Energy closed in 2012, I became Sr. Financial Analyst within the Investor Relations Department, where I was later promoted to Manager. In March 2015, I became Manager, Regional Financial Forecasting within the Financial Planning and Analysis Department, where I was later promoted to Director, Regional Financial Forecasting. I currently lead forecasting for Duke Energy's Midwest electric utilities, including Duke Energy Kentucky, Duke Energy Ohio, Inc., (Duke Energy Ohio) and Duke Energy Indiana, LLC., in addition to Duke Energy's other gas utilities and ventures.

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

A. I am responsible for preparing the budgets and forecasts as well as performing financial analysis for Duke Energy Kentucky and Duke Energy Ohio.

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

A. Yes.

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

A. My testimony will address Duke Energy Kentucky's 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 then describe the budgeting and forecasting process underlying the projected data for the test period proposed in this Application. I also discuss the budget variance reports, which provide the variance analysis for the test period. I sponsor and support the forecasted operating revenues and expenses prior to proforma adjustments and the long-term financial forecast that were prepared under my direction and control.

I sponsor Filing Requirements (FR) 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), 16(6)(a), 16(6)(b), 16(6)(d), 16(6)(e), 16(7)(b), 16(7)(c), 16(7)(d), 16(7)(f), 16(7)(g), 16(7)(h), FR 16(7)(j), FR 16(7)(l), 16(7)(o), 16(7)(r). 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 supported by Duke Energy Kentucky witness Ms. Cynthia Lee. I sponsor the information contained in B-5 and B-5.1 and certain information contained in Schedule B-8 that is supported by Duke Energy Kentucky witness Mr. Michael Covington. 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 sponsor Schedules J-1 through J-4 in response to Filing Requirement (FR) 16(8)(j). Finally, 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. 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 within the rating agencies' guidelines for Duke Energy Kentucky's credit rating; 2) maintaining strong credit quality; 3) ensuring timely recovery of prudently incurred costs; 4) maintaining sufficient cash flows to meet obligations; and 5) 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. There are many reasons why our customers will benefit from the credit rating objectives that we have established. The benefits of achieving and maintaining a strong, investment-grade, credit rating are discussed in the pre-filed testimony of Duke Energy Kentucky witness Dr. Roger A. Morin. These benefits 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 $10,542,199, equating to an approximate 11.05 percent increase in overall rates. As part of this request, supported by the analysis and testimony of Duke Energy Kentucky witness Dr. Roger Morin, the Company is requesting an allowed ROE of 9.9 percent. The proposed capitalization in this request is comprised of 50.755 percent equity and 49.245 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 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	A-	Baa1
Outlook	Stable	Stable

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. S&P affirmed its A- rating and stable outlook in March 2018. Moody's affirmed its Baa1 rating and stable outlook in January 2018.

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 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 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 last affirmation of the Company's ratings, 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. 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;
- Credit supportive regulatory environment in Kentucky; and
- Support from the Duke Energy corporate family.

Credit Challenges:

- Limited recent regulatory track record
- Increasing capital expenditures, and;
- Relatively small size compared to other integrated utilities.

The rating agencies speak to the importance of a constructive regulatory framework and Duke Energy Kentucky's limited activity with base rate cases in recent years. Such comments highlight the importance of this proceeding's outcome in supporting credit quality and the Company's financial objectives.

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 49.245 percent debt and 50.755 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 Dr. Roger Morin testifies that the Company's cost of equity is in the range of 9.2 percent to 10.6 percent, with a midpoint of 9.9 percent. The Company supports Dr. Morin's analysis and is requesting 9.9 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 November 2018)	**Forecast Period** (Avg of Mar 2019 thru Mar 2020)
Short-Term Debt (Schedule J-2)	4.375 percent	4.250 percent
Long-Term Debt (Schedule J-3)	4.331 percent	4.398 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 April 2018. 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 May 2018 plus a 75 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 May 2018.

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 May 2018 plus a 25 basis point credit spread. Two long-term, senior unsecured, debt issuances each totaling $50 million are forecasted for September 2018 based on company projections. The interest rates on these future issuances were estimated using Bloomberg's forward curves for the 10-year and 30-year US Treasury yield, respectively, as of May 2018 plus a 120 basis point credit spread for the 10 year debt offering and a 140 basis point credit spread for the 30 year debt offering. Another $130 million long-term debt issuance is forecasted for September 2019 based on company projections. The interest rate on this future issuance was estimated using a blended average of Bloomberg's forward curves for the 10-year and 30-year US Treasury yield as of May 2018 plus a blended average credit spread.

Q. DID DUKE ENERGY COMPANY TAKE ANY STEPS SINCE ITS LAST NATURAL GAS RATE CASE IN 2009 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 2009. In that rate case, the average cost of long-term debt for the forecasted period was expected to be approximately 4.70 percent. In this rate case, the average cost of long-term debt is expected to be approximately 4.40 percent. In Duke Energy Kentucky's most recent debt offering, the Company priced $90 million of debt through the traditional private placement market. The transaction was well received by the market and achieved efficient pricing across three series of notes at a weighted-average cost of approximately 3.90 percent and a weighted average life of 27 years.

V. <u>DUKE ENERGY KENTUCKY'S CAPITAL REQUIREMENTS</u>

Q. WHAT ARE DUKE ENERGY KENTUCKY'S CAPITAL REQUIREMENTS DURING THE 2018-2020 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 $612 million during the period – 2018-2020. This amount consists of approximately $511 million in projected capital expenditures and approximately $101 million in debt maturities.

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

A. Duke Energy Kentucky's capital requirements are expected to be funded from internal cash generation, the issuance of debt, and equity contributions. 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. 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 2017 actual data and its 2018 annual budget. This is because the Company is using a base period that spans two calendar years and is comprised of actual data for 2017 and both actual and budgeted data for 2018. The Company is also using a fully forecasted test period that, for this proceeding, spans the twelve-month period ending March 31, 2020. I supervised the coordination and development of this budget and forecast data, and it was reviewed and approved by Duke Energy Kentucky's executive management and Duke Energy's Board of Directors.

Q. HOW DID YOU USE THE 2018 ANNUAL BUDGET RESULTS FOR THE BASE AND FORECASTED PERIODS IN THIS PROCEEDING?

A. The base period is the twelve months ending November 30, 2018, and consists of six months of actual data through May 2018 and the remaining six months of budgeted data. The forecasted test period is the twelve months ending March 31, 2020. The Company's 2017 actual data and 2018 budget were the starting point for the preparation of both the base and forecasted periods. A simplistic high-level summary of that approach is as follows. First, I revised the 2018 Annual Budget for a limited number of updated assumptions, as I describe in detail later in my testimony. Next, I extended the revised 2018 budget to March 2020 using the Company's standard forecasting methodology, which I also 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 May 2018.

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 non-union labor expenses and indirect labor and fringe benefit loading rates, and how to handle staff additions or deletions. Individual employees and certain associated costs of the employees are included or excluded in any given center's budget according to the expected future reporting assignment for that employee. 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, and guidelines for identifying a capital versus expense item. Budget coordinators are required to use these assumptions and/or instructions in projecting their future departmental expenses. These operating and maintenance (O&M) budgeting guidelines are reflected in the budgets and forecasts that are submitted to Duke Energy Kentucky's executive management and Duke Energy's Board of Directors for approval and are also reflected in the forecasted financial data in these proceedings.

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

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

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

VII. 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 2018 annual budget was to obtain a forecast of the projected gas sales on a thousand cubic feet basis

(MCF) and electric kilowatt per hour (kWh) sales from Duke Energy Kentucky witness Benjamin Walter Bohdan Passty, Ph.D., Lead Load Forecasting Analyst, who prepared the load forecasts on a monthly basis for each customer class over a five-year period. 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 and kWh sales were calculated by applying the tariff charges to these sales forecast numbers for all gas customers and for residential electric customers. The projected revenue for electric non-residential customers was calculated by applying average realizations to their respective kWh sales forecasts.

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

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

Q. HOW WERE OTHER REVENUES PROJECTED?

A. Other revenue categories, such as PJM reactive revenues, reconnection charges, late payment fees, *etc.*, for Duke Energy Kentucky's 2018 and 2019 annual budgets are projected based on historical trends or are provided by the individual budget centers.

Q. HOW DID YOU OBTAIN THE FUEL, PURCHASED POWER AND PURCHASED GAS EXPENSE FOR THE INCOME STATEMENT PORTION OF THE ANNUAL BUDGET?

A. The level of fuel, purchased power and purchased gas expense are derived from the projected cost per unit of the fuel consumed and the volume of the consumption determined by the gas and electric sales forecasts. The Business Development and Analytics Department provided the electric fuel and purchased power expense by combining forecasted sales and pricing of various inputs and simulating generation output and associated costs with their business model. Duke Energy Kentucky witness Mr. Gary J. Hebbeler provided the gas supply mixture and purchased gas expense. Both Mr. Hebbeler and the Business Development and Analytics Department also provided this information for the five-year forecast.

Q. HOW DID YOU OBTAIN THE REMAINING OPERATING EXPENSES FOR THE INCOME STATEMENT PORTION OF THE ANNUAL BUDGET?

A. The individual budget centers provide the operation and maintenance (O&M) expenses, including payroll taxes and other revenue taxes, for all of Duke Energy Kentucky. Duke Energy Kentucky was also allocated Administrative and General (A&G) expenses and O&M expenses from DEBS and other affiliates, as discussed by Duke Energy Kentucky witness Mr. Jeffrey Setser. The regulatory assets were amortized using the amortization schedules approved by the Kentucky Public Service Commission.

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

A. The forecasted depreciation for current and projected new gas plant was calculated by multiplying the original cost of current and projected new gas plant by the composite depreciation rates. This calculation was performed for the base and forecasted periods. Duke Energy Kentucky witness Ms. Cynthia Lee provided me with the original cost of the current gas and electric plant along with the current depreciation rates. Then various groups within the Company supply budgeted capital expenditures for all types of property held by Duke Energy Kentucky. 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 2018 and 2019 Annual Budget by the various responsibility centers, using the bottom-up approach that I previously described. 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 Ms. Renee Metzler to budget 2018 and 2019 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, while non-union labor cost increases were assumed to be 3.5 percent. I also used the fringe benefit loading rates (21.1 percent) and payroll tax (7.65 percent) loadings. Non-labor expenses for 2018 and 2019 were forecasted by the responsibility centers based on their knowledge and expectations for various costs.

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

A. As mentioned above, O&M budgets were supplied by the responsibility centers for 2018 and 2019 per the company's Budget Guidelines. The basis for the 2020 budget is the 2019 budget adjusted for various O&M expenses that are expected to diverge from general escalation assumptions. Apart from these adjustments, O&M expense is assumed to escalate one percent in 2020 from projected 2019 levels.

In certain instances, new or revised information emerged which supported the need for revisions to previously supplied O&M budgets and projections. An example includes O&M reductions, or savings, from the corporation's efficiency efforts. These savings were added to, or credited against, the original budgets and projections from the responsibility centers.

Q. HOW DID YOU OBTAIN THE PROPERTY TAX EXPENSE?

A. The property tax expense was obtained from the 2018 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 test period data, based on the capital projections.

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

A. The "other income and expense" is a below-the-line item, and is derived from a combination of sources. The amount of funds for the AFUDC was derived from the gas and electric capital forecasts prepared for the 2018 annual budget. These capital forecasts were supplied by Duke Energy Kentucky's gas operations businesses.

Q. HOW DID YOU OBTAIN THE INTEREST EXPENSE?

A. Duke Energy's Treasury Department provided the long-term debt balances and long- and short-term interest rates for the revised 2018 annual budget and the 2019 and 2020 forecasts.

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). The income tax expense was derived using Utilities International (UI) Planner or "proprietary forecasting" software for each month of the revised 2018 annual budget period and the 2019 and 2020 forecasts, by applying statutory income tax rates to applicable taxable book income and adjusting the resulting applicable income taxes by the ITC 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 May 2018 balances. Duke Energy Kentucky witness, Ms. Cynthia A. Lee supplied the net book value for the existing gas, electric and common plant and construction work in progress for the period ending May 2018 for the local natural gas distribution property. I used the proprietary forecasting software to calculate the depreciation expense and net gas, electric, 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. Hebbeler 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 2018 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 revised 2018 annual budget and the 2019 and 2020 forecasts. In addition, Ms. Lee supplied the Plant inventories.

C. CASH FLOW STATEMENT

Q. HOW DID YOU PREPARE THE CASH FLOW STATEMENT FOR THE 2018 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.

VIII. REASONABLENESS OF THE FORECASTED TEST PERIOD DATA

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

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

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

A. Yes.

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

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

IX. 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 June 30, 2018.

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

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

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

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

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

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

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

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

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

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

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 FR 16(7)(r).

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

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

A. I provided Ms. Lee with the forecasted data contained in those schedules.

Q. PLEASE DESCRIBE SCHEDULE B-5.

A. Schedule B-5 is a summary of the jurisdictional working capital calculation based on the Commission's traditional methodology. The calculation includes a cash element of working capital, and material and supplies inventory.

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 $1,143,072.

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 $1,284,114 and $2,958,880, respectively.

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

A. Cash working capital was computed for both the base and forecasted periods. It represents the financing incurred to bridge the gap between the time when expenditures are incurred to provide service and the time when payment is received for that service. The cash working capital computation is based upon the traditional methodology used by this Commission, which is one-eighth of O&M expense, as adjusted, excluding purchased gas costs. For the base period, the resulting jurisdictional cash working capital is $2,978,574 and for the forecasted period cash working capital is $3,021,735.

Q. PLEASE EXPLAIN THE INFORMATION YOU SUPPORT IN SCHEDULE B-8.

A. Schedule B-8 includes the comparative Balance Sheets for the total Company. I sponsor the forecast period and budget information in the base period on this schedule.

Q. PLEASE DESCRIBE SCHEDULE D-2.1.

A. Schedule D-2.1 adjusts base period revenue to the level included in the forecasted test period. The adjustment results in a net revenue decrease of $7,916,529.

Q. PLEASE DESCRIBE SCHEDULE D-2.2.

A. Schedule D-2.2 adjusts base period purchased gas expenses to the level included in the forecasted test period. The effect of the adjustment on Duke Energy Kentucky's natural gas operations is a decrease in pre-tax operating expenses of $8,901,897.

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 natural gas operations is an increase in pre-tax operating expenses of $839,469.

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 $671,111.

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. There are no transmission expenses in the base period or forecasted period.

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 $1,970,875.

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 a decrease in pre-tax operating expenses of $497,608.

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 a decrease in pre-tax operating expenses of $7,963.

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 $32,237.

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 $593,730.

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 an increase of pre-tax operating expenses of $801,635.

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 $1,303,985.

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 $536,096.

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 a decrease in income tax expense of $1,764,165.

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 increase revenues in the forecasted test period by $1,766,010

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, stock and bond ratings and fixed charge coverage data on page 3, forecasted data on page 4 and the mix of sales and fuel on page 5, for the base period and the forecasted test period.

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 November 30, 2018, and the average of the projected balances and rates for the thirteen-month period ending March 31, 2020. 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 March 31, 2020.

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, November 30, 2018. 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 March 31, 2020.

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 percentage of construction expenditures financed internally, fixed coverage ratios and 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, various credit ratios and the percentage of construction expenditures financed internally. I also provided information relating to consolidated capital structure and common stock related data to Mr. Covington and Ms. Lee for their use in preparing Schedule K.

X. CONCLUSION

Q. WAS THE INFORMATION YOU SPONSOR IN 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(6)(a), FR 16(6)(b), FR 16(6)(d), FR 16(6)(e), FR 16(7)(b), FR 16(7)(c), FR 16(7)(d), FR 16(7)(f), FR 16(7)(g), FR 16(7)(h), FR 16(7)(j), FR 16(7)(l), FR 16(7)(o), FR 16(7)(r), FR 16(8)(b), FR 16(8)(d), FR 16(8)(i), AND FR 16(8)(k), THE INFORMATION YOU PROVIDED TO MS. LEE FOR SCHEDULES B-2, B-2.1, B-2.2, B-2.3, B-2.4, B-2.5, B-2.6, B-2.7, B-3, B-3.1, B-3.2, B-4, SCHEDULES B-5 AND B-5.1, D-2.1 THRU D-2.14, AND D-2.25 AS WELL AS SCHEDULES I-1 THORUGH I-5, J-1 THROUGH J-4 IN RESPONSE TO FR 16(8)(j), AND SCHEDULE K PREPARED BY OR SPONSORED AND SUPPORTED BY YOU?

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.

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Robert H. "Beau" Pratt., Director, Regional Financial Forecasting, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

Robert H. "Beau" Pratt

Robert H. "Beau" Pratt Affiant

Subscribed and sworn to before me by Robert H. "Beau" Pratt on this 7 day of August, 2018.

Virginia M. Adams

NOTARY PUBLIC

VIRGINIA M. ADAMS NOTARY PUBLIC MECKLENBURG COUNTY, NC Exp. 10/02/2021

My Commission Expires:
10/2/21

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 a Decoupling Mechanism; 3) Approval of New Tariffs; and 4) All Other Required Approvals, Waivers, and Relief.	)))))))	Case No. 2018-00261

DIRECT TESTIMONY OF

BRUCE L. SAILERS

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

August 31, 2018

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND PURPOSE 1
II. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS 3
III. RETAIL ELECTRIC RATE SCHEDULES AND RIDERS 8
A. RATE DESIGN AND MAJOR RETAIL ELECTRIC RATE SCHEDULES 8
B. WEATHER NORMALIZATION ADJUSTMENT RIDER (RIDER WNA) 12
C. MISCELLANEOUS NEW OR REVISED RIDERS 16
IV. OTHER TARIFF CHANGES 19
V. CHANGES TO TARIFF LANGUAGE AND SERVICE REGULATIONS. 22
VI. CONCLUSION 23

Attachments:

BLS-1 – Newspaper Notice

BLS-2 – Cost of Service Study Customer Components and Customer Charge Calculation

BLS-3 – WNA Bill Adjustment Example

BLS-4 – WNA Impact Estimates

BLS-5 – Reconnection Charge Calculation

BLS-6 – Meter Pulse Service Charge Calculation

BLS-7 – Rate IMBS Monthly Imbalance Charge Calculation

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bruce L. Sailers. 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 Pricing and Regulatory Solutions 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 received a Bachelor's Degree in Finance and Quantitative Analysis and a Master's Degree in Marketing from the University of Cincinnati. After three years working with Marathon Oil Company as a systems analyst, I began my career with The Cincinnati Gas & Electric Company, a predecessor to Duke Energy Ohio, in Load Forecasting. I worked in the Load Forecasting area for approximately five years in various capacities, and then transferred to Market Research for approximately ten years. In early 2006, I became Manager, Product Development Analytics where I was responsible for demand response product support analysis, certain demand response product operational support functions, demand response product measurement and verification, and demand response product Regional Transmission Organization (RTO) integration for Duke Energy affiliates, including Duke Energy Kentucky. Having these same responsibilities, my title changed to Manager, Retail Energy Desk and then Manager, Demand Response Analytics. I assumed my current role under the title Rates and Regulatory Strategy Manager, Pricing & Rate Options, in January 2014. Having the same responsibilities, my title has since changed to Pricing and Regulatory Solutions Manager.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS PRICING AND REGULATORY SOLUTIONS MANAGER.

A. As Pricing and Regulatory Solutions Manager, 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. Most recently, I provided testimony in Case No. 2017-00321 Duke Energy Kentucky's base electric rates proceeding. In addition, I have also provided testimony in cases before the Indiana Utility Regulatory Commission, the North Carolina Utilities Commission, and the Public Utilities Commission of Ohio.

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

A. I am responsible for Duke Energy Kentucky's proposed 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 President's name, version number, and/or the schedule's filing and effective date. There are no substantive changes to these tariff schedules which include sheet numbers 20, 22, 23, 26, 27, 28, 29, 59, 60, 61, 62, 70, 77, 80, and 82.

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 10.2 percent increase in the Residential service class, a 10.5 percent increase in the General Service class, a 30.7 percent increase in the Firm Transportation-Large service class, and an 8.1 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 March 31, 2020. Schedule M-2.2, pages 2 through 7, 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. Schedules M-2.2 and M-2.3 are also provided for the base period.

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 FR 16(8)(l).

A. FR 16(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 11.3 percent, which breaks down as previously described. (Note that the 11.3 percent value includes the current DSM rider. Excluding the current DSM rider, the percent increase is 11.05 or 11.1 (rounded). This 11.1 percent value is used in other locations in the Company's application.) 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.

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 October 1, 2018 and the dates the proposed rates are expected to be filed are August 31, 2018.

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. FR 17(4)(d) shows the amount of the average usage and the effect on the average bill for each customer classification to which the proposed rates will apply.

Q. PLEASE DESCRIBE FR 17(4)(e) THROUGH (j)

A. FR17(4)(e) through (j) are statements required for inclusion in the Company's notice to customers, including that customers may examine the Company's application at its offices, at the Commission's offices, or on its website. The statements include instructions for submittal of comments to the Commission and that the rates are only proposed and could be changed by the Commission, as well as instructions for intervention. As evidenced by the Company's Notice, Attachment BLS-1, these various statements are included.

III. RETAIL 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 15 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 proposes a Weather Normalization Adjustment (WNA) Rider applicable to Rates RS and GS. This new rider will normalize 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 weather during winter months. To focus on the new Rider WNA, the Company does not propose significant structural changes to the underlying rate schedules.

Q. WHAT ARE THE PROPOSED CUSTOMER CHARGES?

A. The proposed customer charge for each rate is as follows: for Rate RS, $17.50; for Rate GS, $50.00; for Rate IT, $430.00; and for Rate FT-L, $430.00. Attachment BLS-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. For Rate RS, the current customer charge is $16.00 and, combined with the $1.80 per bill current charge for Rider ASRP, represents a total $17.80 fixed component of residential customers' bill. As shown in attachment BLS-2, the cost of service study supports a value of $24.61. However, the Company proposes the customer charge of $17.50. When factoring in the fixed charge of the Rider ASRP, which will actually be terminated as part of this proceeding, the modest $1.50 increase to the RS customer charge actually represents a $0.30 reduction in the overall fixed portion of the residential natural gas customer's bill. This $1.50 increase aligns with the rate design principle of gradualism and as stated above, can be viewed as a slight reduction in residential customer's fixed component of the residential customer bill. Similarly, the Rate GS customer charge is proposed to modestly increase from the current value of $47.50 to $50.00.

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 of $430.00.

Q. HAVE YOU PREPARED RATE SCHEDULES FOR THE COMPANY'S NATURAL GAS RATES?

A. Yes. Again, there are no significant structural changes other than the new Rider WNA discussed below. 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.

Q. ARE THERE ADDITIONAL CHANGES PROPOSED FOR RATE SCHEDULES FT-L AND IT?

A. Yes. Text changes are made in both rate schedules to specify a modification in customer obligations related to remote metering. Customers under both rate schedules will be required to provide electrical service near the meter site instead of telephone service to support the Company's telemetering equipment. The Company is specifically requiring the presence or installation of a dedicated 110v electrical service instead of relying on the current tariff language requiring the customer to provide other utilities or equipment as may be necessary. As more customers are migrating away from traditional land line phone services, the Company has faced obstacles in configuring analog phone line telemetering installations and with equipment obsolescence. After researching best practices within Duke Energy's footprint, the Company is replacing its meter head-end system used for large volume gas transportation customers with a solution that utilizes existing SCADA communications and software. The new telemetering solution and field devices will increase the reliability of daily gas flow data for both large volume customers and their designated pool operators, as well as address the technical obsolescence of current hardware/field devices.

Q. ARE THERE OTHER CHANGES PROPOSED FOR RATE SCHEDULE IT?

A. Yes. The Minimum Bill section of Rate IT is updated to clarify the applicability of Riders when applying summer minimum charges to customers that fail to take delivery of 10,000 CCF per month. Also, the Charges for Unauthorized Deliveries section of Rate IT is updated to clarify the charges that apply to customers taking unauthorized deliveries. This change is for clarification purposes only; no new charges are proposed.

B. WEATHER NORMALIZATION ADJUSTMENT RIDER (RIDER WNA)

Q. DOES THE COMPANY PROPOSE A WEATHER NORMALIZATION ADJUSTMENT RIDER (RIDER WNA) AS PART OF THIS PROCEEDING?

A. Yes. The Company includes the Weather Normalization Adjustment Rider (Rider WNA), Sheet No. 65, available in Schedule L-1.

Q. CAN YOU DESCRIBE RIDER WNA?

A. Yes. 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. Ben 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 proposes a WNA mechanism that adjusts the volumetric component of base delivery charges on customer bills to reflect normal weather conditions.

Q. CAN YOU CONTINUE?

A. 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 proposed 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 proposed 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 Company witness Passty's testimony, the initial values for BL and HSF are 1.106333 Mcf and 0.015283 Mcf/DD, respectively, for Rate RS. For Rate GS, they are 9.745755 Mcf and 0.090515 Mcf/DD, respectively. These proposed values will be updated annually as I discuss below.

Q. PROVIDE A BILL EXAMPLE OF THE WNA RIDER ADJUSTMENT CALCULATION AND THE INFORMATION CUSTOMERS WILL SEE ON THEIR BILL.

A. An example bill calculation is provided in Attachment BLS-3. Customers will see a new line in the gas rider section of their bill during the winter season showing the WNA value, the CCF consumption, and the resulting charge or credit.

Q. WHEN DOES THE COMPANY PROPOSE TO INTIATE RIDER WNA?

A. The Company projects that the Commission will issue an order in this proceeding in March 2019, which would suggest that rates would be effective for the first billing cycle in April 2019. However, given the seasonal nature of this adjustment, and the fact that the Company's new rates would not become effective until after the 2018/2019 winter heating season, the Company requests to initiate the WNA Rider with the first billing cycle of November 2019. This implementation schedule would allow the Company ample time to communicate the rider implementation to customers.

Q. DOES THE COMPANY PROPOSE A PROCEDURE FOR REPORTING RIDER WNA SEASONAL RESULTS TO THE COMMISSION?

A. The Company anticipates the requirement to file an annual report containing Rider WNA impacts to the Commission each year with Duke Energy Kentucky's first report submitted during the summer of 2020. Given that the Commission is experienced with procedures for WNA reporting from other gas utilities in Kentucky, the Company is open to the Commission's direction on the details of Rider WNA reporting requirements. Further, the Company proposes to submit annual updates to the Rider WNA class parameters (*i.e.*, BL and HSF) but remains open to the Commission's direction if it prefers that these parameters are updated only during natural gas base rate case filings.

Q. DOES THE COMPANY HAVE INFORMATION ON RIDER WNA DELIVERY CHARGE MONTHLY REVENUE IMPACT ESTIMATES SINCE 2015?

A. Yes. Using monthly data from Attachment BLS-4, the WNA delivery charge/credit adjustments are estimated for the 2015-2016, 2016-2017, and 2017-2018 winter seasons. The total WNA seasonal adjustments (Rate RS and Rate GS summed) would have been $4,390,971; $4,220,034; and $(1,157,134), respectively, if the WNA Rider was in effect for those periods.

Q. ARE THE ADJUSTMENTS ABOVE CONSISTENT WITH HEATING DEGREE DAY DATA?

A. Yes. For the winter of 2015-2016, actual heating degree days (base 59) totaled 2,762. Normal heating degree days are 3,453. This winter was much warmer than normal and a WNA surcharge would be expected. For the winter of 2016-2017, normal degree days are 3,429 and actual degree days totaled 2,770. This is a similar result as the previous winter. For the winter of 2017-2018, normal degree days are 3,441 and actual degree days totaled 3,625. This winter was colder than normal and a WNA credit would be expected as shown above.

C. REVISED RIDERS AND MISCELLANEOUS CHARGES

Q. DOES THE COMPANY PROPOSE TO ELIMINATE ANY TARIFF SCHEDULES IN THIS CASE?

A. Yes. Duke Energy Kentucky is proposing to eliminate the Spark Spread Interruptible Transportation rate, Rate SSIT, and the Accelerated Service Replacement Program rider, Rider ASRP.

Q. WHY DOES THE COMPANY PROPOSE TO ELIMINATE RATE SSIT?

A. Currently, there are no customers served under Rate SSIT, Sheet No. 53, and in fact, no customers have ever participated on this rate. Further, the Company is not aware of any customers interested in participating in this rate schedule. Therefore, the Company proposes to cancel and withdraw Rate SSIT.

Q. WHY DOES THE COMPANY PROPOSE TO ELIMINATE RIDER ASRP?

A. Rider ASRP is a service replacement program rider that the Company proposes to transition recovery of the associated costs to base rates as more fully explained in Company witness Gary J. Hebbeler's testimony. Therefore, the Company proposes to cancel and withdraw the Rider ASRP schedule, Sheet No. 63.

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 $75.00.

(2) The reconnection charge for service which has been disconnected within the preceding twelve months at the request of the customer shall be $75.00.

(3) The reconnection charge for service which has been disconnected because of fraudulent use shall be $75.00.

Q. ARE THERE ADDITIONAL CHANGES TO THE CHARGES FOR RECONNECTION OF SERVICE SCHEDULE?

A. Yes. Currently, Duke Energy Kentucky incorporates the charge for reconnection of two services, gas and electric, at the premise at the same time in both the electric tariff and the gas tariff. This can lead to a mismatch in the reconnection charges presented to customers in the tariffs when the Company has an electric base rate case without a natural gas base rate case and vice versa. Further, this can be confusing to natural gas and electric service customers that have the capability to have electric service reconnected remotely. For safety, natural gas service is not reconnected remotely. The Company must still deploy a technician to reconnect natural gas service to all customers, even those that have advanced metering capability. To alleviate confusion, the potential mismatch of published charges, and avoid any potential timing discrepancies between the Company's electric and natural gas tariffs, the Company is proposing a simple language change to its natural gas reconnection fee as it relates to combination natural gas and electric customers. Specifically, the Company is proposing to simply reference and direct combination natural gas and electric customers to the Company's electric service Charge for Reconnection of Service, Electric Sheet No. 91, where the charge for reconnecting both services is provided.

Q. WHAT INFORMATION IS USED TO SUPPORT THE SERVICE RECONNECTION COSTS?

A. Attachment BLS-5 shows the calculation of natural gas service reconnection and the Company's proposed value.

Q. DESCRIBE THE INFORMATION PRESENTED IN ATTACHMENT BLS-5, 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.

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 $550.00 and $560.00, respectively, due to the increased cost to provide this equipment as supported in Attachment BLS-6.

IV. <u>OTHER TARIFF CHANGES</u>

Q. WHAT CHANGES ARE PROPOSED FOR THE FULL REQUIREMENTS AGGREGATION SERVICE RATE, RATE FRAS?

A. Text changes are made in Rate FRAS to clarify certain definitions and supplier responsibilities related to city gate receipt points and Operational Flow Order charges. Changes related to city gate receipt points include clarification of Duke Energy Kentucky's authority to direct suppliers to deliver gas at specified city gate receipt points and removal of a three-month limitation on that authority.

Duke Energy Kentucky requests suppliers to deliver at specified receipt points only for operational reasons, which could occur any month of the year.

Q. WHAT CLARIFICATIONS IN OPERATIONAL FLOW ORDER CHARGES ARE PROPOSED?

A. Unauthorized over-deliveries of gas during an Operational Flow Order will result in those over-deliveries being cashed out to the supplier at the lowest cost of gas available to the Company on the date of non-compliance, instead of confiscation by the Company without compensation to the supplier. This revised treatment would be consistent with how unauthorized over-deliveries are charged under Duke Energy Kentucky's interruptible transportation program. Other changes add clarifying details regarding how unauthorized under-delivery and over-delivery charges are calculated, *e.g.*, the applicability of transportation and fuel charges to the Company's city gate.

Q. WHAT CHANGES ARE PROPOSED FOR THE INTERRUPTIBLE MONTHLY BALANCING SERVICE, RATE IMBS?

A. The monthly imbalance carry over tolerance level table for monthly imbalance charges is updated to provide a single level of tolerance and associated rate. The cost differences in the existing three tolerance levels have become insignificant and, therefore, the three levels are condensed to one level. Calculations to support the imbalance charge of $0.1097 / MCF are provided in Attachment BLS-7.

Q. ARE THERE ADDITIONAL CHANGES PROPOSED FOR THE INTERRUPTIBLE MONTHLY BALANCING SERVICE, RATE IMBS?

A. Yes, text changes include clarification of unauthorized overrun/underrun charges, a shortened time period to complete an imbalance trade, and a change in how a customer's or pool operator's monthly imbalance percentage will be determined. Unauthorized overrun/underrun charges are now specifically stated within the Net Monthly Bill provision of Rate IMBS instead of the prior reference to Rate IT, Interruptible Transportation Service. The shortened time period to complete an imbalance trade is addressed in Rate GTS, Gas Trading Service, and is proposed for efficiency and consistency. In addition, the monthly imbalance percentage will be determined by dividing the net monthly imbalance by "pool usage" instead of "pool deliveries." This is a more accurate method to measure the monthly imbalance percentage, since pool usage is the target that pool operators are trying to match on a monthly basis.

Q. WHAT CHANGES ARE PROPOSED FOR THE POOLING SERVICE FOR INTERRUPTIBLE GAS TRANSPORTATION, RATE AS?

A. No changes are made to Rate AS other than to change the name of the rate from Pooling Service for Interruptible Gas Transportation to Aggregation Service for Interruptible Gas Transportation.

Q. WHAT CHANGES ARE PROPOSED FOR THE GAS TRADING SERVICE, RATE GTS?

A. The time period to complete imbalance trades is shortened from four business days from the date that the trade applies to two business days. This change will allow Duke Energy Kentucky efficiency gains in the monthly closing and billing process, as well as to obtain consistency with other Duke Energy jurisdictions.

V. CHANGES TO SERVICE REGULATIONS

Q. IS DUKE ENERGY KENTUCKY PROPOSING ANY TARIFF LANGUAGE CHANGES TO SERVICE REGULATIONS?

A. Yes. Duke Energy Kentucky is proposing to amend Section II Supplying and Taking of Service, Sheet No. 21, to clarify situations whereby sub-metering is permitted in master-meter installations. Currently the Company's tariff prohibits the installation of sub metering. The Company is amending its tariff to allow the installation of sub metering as long as the master meter account is only using the meter to allocate the Company's bill among users and not reselling the Company's delivered natural gas. This situation arises in multi-family premises such as a condominium or apartment complex, where the Company has a single meter for the building, but the interior of the premises is divided into multiple units. The Company would agree to permit such sub metering for allocation of the Company's natural gas bill and not for reselling of the company's delivery of natural gas with a mark-up.

Q. WHAT ADDITIONAL CHANGES ARE MADE TO THE COMPANY'S SERVICE REGULATIONS?

A. The Company makes changes to its service regulations in Section V, Metering, and Section VI, Billing & Payment.

Q. PLEASE DESCRIBE THE ADDITIONAL CHANGES DUKE ENERGY KENTUCKY IS PROPOSING TO ITS SERVICE REGULATIONS.

A. In Section VI, Billing & Payment, the Company revises Section VI.5. In Section VI.5, the Company provides a description of the budget billing plans offered to customers. In addition, in Section V - Metering, Section V.3.1 and V.3.2 are revised to generalize the description of the Hi/Lo customer monthly usage review process. As more detailed data is collected on customers, the Hi/Lo review process can be enhanced. All other changes to the Company's service regulations are cosmetic, spelling, or grammar corrections.

VI. <u>CONCLUSION</u>

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 October 1, 2018, 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 BLS-1, BLS-2, BLS-3, BLS-4, BLS-5, BLS-6, AND BLS-7, 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.

<u>**VERIFICATION**</u>

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, Bruce L. Sailers, Pricing and Regulatory Solutions Manager, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

Bruce L. Sailers

Bruce L. Sailers, Affiant

Subscribed and sworn to before me by Bruce L. Sailers, on this 30th day of August, 2018.

Adele M. Frisch

NOTARY PUBLIC

ADELE M. FRISCH
Notary Public, State of Ohio
My Commission Expires 01-05-2019

My Commission Expires: 1/5/2019

NOTICE

Duke Energy Kentucky, Inc. (Duke Energy Kentucky) hereby gives notice that it will file an application on or about August 31, 2018 seeking approval by the Kentucky Public Service Commission of an adjustment of natural gas rates to become effective on and after October 1, 2018. The Commission has docketed this proceeding as Case No. 2018-00261.

The proposed natural gas rates are applicable to the 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 PRESENT AND PROPOSED RATES

The present and proposed rates charged in all territories served by Duke Energy Kentucky are as follows. The current GCA Rate in effect as of August 1, 2018 is $0.4170 per CCF.

Residential Service - Rate RS

	Present Rates	Proposed Rates
Monthly Customer Charge:	$16.00	$17.50
Base Rate for all Ccf	$0.37213	$0.48677
GCA for all Ccf	$0.41700	$0.41700
Total Rate (Base Rate + GCA) for all Ccf	$0.78913	$0.90377

General Service - Rate GS

	Present Rates	Proposed Rates
Monthly Customer Charge:	$47.50	$50.00
Base Rate – All Ccf	$0.20530	$0.28077
GCA – All Ccf	$0.41700	$0.41700
Total Rate (Base Rate + GCA) for all Ccf	$0.62230	$0.69777

Interruptible Transportation Service - Rate IT

	Present Rates	Proposed Rates
Monthly Customer Charge:	$430.00	$430.00
Base Rate – All Ccf	$0.09493	$0.10369

Firm Transportation Service-Large - Rate FT-L

	Present Rates	Proposed Rates
Monthly Customer Charge:	$430.00	$430.00
Base Rate – All Ccf	$0.17369	$0.23319

Interruptible Monthly Balancing Service - Rate IMBS

Present Rate
Transportation customers who avail themselves of the service under this rate schedule must, with the agreement of their supplier, select a monthly imbalance carry over tolerance level from the following options:

	Allowed Monthly Under-Run %	Allowed Seasonal Monthly Over-Run: May Through November %	Allowed Seasonal Monthly Over-Run: December Through April %	Charge on All Throughput
Option 1	0	5	7	$0.015 per Mcf
Option 2	0	6	8	$0.020 per Mcf
Option 3	0	8	10	$0.025 per Mcf

Proposed Rate
Transportation customers who avail themselves of the service under this rate schedule must conform to the monthly imbalance carry over tolerance level shown below.

	Allowed Monthly Under-Run %	Allowed Seasonal Monthly Over-Run: May Through November %	Allowed Seasonal Monthly Over-Run: December Through April %	Charge on All Throughput
All Pools	0	8	10	$0.1097 per Mcf

Weather Normalization Adjustment Rider – Rider WNA

Present Rate
This is a new tariff schedule.

Proposed Rate
APPLICABILITY
Applicable to all customers receiving service under Rate RS, Residential Service, and Rate GS, General Service.

DETERMINATION OF WNA
The distribution charge per Ccf for gas service as set forth in Rates RS and GS shall be adjusted by an amount herein under described as the Weather Normalization Adjustment (WNA).
The WNA shall apply to all Rate RS and Rate GS bills during the November through April billing periods. The WNA shall increase or decrease accordingly by month. The WNA will not be billed during the billing periods of May through October. Customer base loads and heating sensitivity factors will be determined by rate class and adopted from the most recent order of the Kentucky Public Service Commission (KYPSC) approving such factors to be used in the application of this Rider.
The WNA shall be computed by rate class using the following formula:

$$WNA_i = R_i * \frac{(HSF_i * (\mathrm{NDD} - \mathrm{ADD}))}{(BL_i + (HSF_i * \mathrm{ADD})}$$

Where:

i	=	A rate schedule or billing classification within a rate schedule
WNA_i	=	Weather Normalization Adjustment Factor for the ith rate schedule or classification expressed as a rate per Ccf.
R_i	=	Weighted average rate (distribution charge) of temperature sensitive sales for the ith schedule or classification.
HSF_i	=	Heat sensitivity factor for ith rate schedule or classification.
NDD	=	Normal billing cycle heating degree days (based upon Company's 30-year normal period adopted from the most recent order of the KYPSC approving such normal for use in the application of this Rider.
ADD	=	Actual billing cycle heating degree days.
BL_i	=	Base load for the ith rate schedule or classification.

Charge for Reconnection of Service

Present Rate

The Company may charge and collect in advance the following:

A. The reconnection charge for service which has been disconnected due to enforcement of Rule 3 shall be twenty-five dollars ($25.00).
B. The reconnection charge for service which has been disconnected within the preceding twelve months at the request of the customer shall be twenty-five dollars ($25.00).
C. If service is discontinued because of fraudulent use thereof, the Company may charge and collect in addition to the reconnection charge of twenty-five dollars ($25.00) the expense incurred by the Company by reason of such fraudulent use, plus an estimated bill for gas used, prior to the reconnection of service.
D. If both the gas and electric service are reconnected at one time, the total charge shall not exceed thirty-eight dollars ($38.00).

Proposed Rate

The Company may charge and collect in advance the following:

A. The reconnection charge for service which has been disconnected due to enforcement of Rule 3 shall be seventy-five dollars ($75.00).
B. The reconnection charge for service which has been disconnected within the preceding twelve months at the request of the customer shall be seventy-five dollars ($75.00).
C. If service is discontinued because of fraudulent use thereof, the Company may charge and collect in addition to the reconnection charge of seventy-five dollars ($75.00) the expense incurred by the Company by reason of such fraudulent use, plus an estimated bill for gas used, prior to the reconnection of service.
D. If both the gas and electric service are reconnected at the premise at one time, the total charge is available on Company's Electric Tariff Sheet No. 91, Charge for Reconnection of Service.

Meter Pulse Service - Rate MPS

Present Rates

Rate MPS is an optional service available to customers that request the Company to install gas meter pulse equipment, a meter-related service not otherwise provided by the Company. The gas meter pulse equipment provides an electronic pulse output representing a pre-determined natural gas volume. The volume will vary at different meter installations, and will thus be communicated to the customer at the time of installation. Pressure and temperature correcting factors may need to be applied by the customer. The customer is responsible for providing power and communication links to the meter pulse equipment per the Company's specifications. Customer must provide either a regulated 24 volts DC, or 120 volts AC electric supply, to an area 2' x 2', approximately 20' away from any gas pipeline flanges or gas pressure relief devices.

Installation of meter pulse equipment:	$500.00
If replacement of Meter Index is necessary, additional charge of:	$155.00

Proposed Rates

Rate MPS is an optional service available to customers that request the Company to install gas meter pulse equipment, a meter-related service not otherwise provided by the Company. The gas meter pulse equipment provides an electronic pulse output representing a pre-determined natural gas volume. The volume will vary at different meter installations, and will thus be communicated to the customer at the time of installation. Pressure and temperature correcting factors may need to be applied by the customer. The customer is responsible for providing power and communication links to the meter pulse equipment per the Company's specifications. Customer must provide either a regulated 24 volts DC, or 120 volts AC electric supply, to an area 2' x 2', approximately 20' away from any gas pipeline flanges or gas pressure relief devices.

Installation of meter pulse equipment:	$550.00
If replacement of Meter Index is necessary, additional charge of:	$560.00

In addition, Duke Energy Kentucky proposes to change the text as noted for the following tariffs:

Service Regulations Section II – Supplying and Taking of Service

Present Rate
6. USE OF SERVICE:
Service is supplied directly to Customer through Company's own meter and is to be used by Customer only for the purposes specified in and in accordance with the provisions of the Service Agreement and applicable Rate Schedule. Service is for Customer's use only and under no circumstances may Customer or Customer's agent or any other individual, association or corporation install meters for the purpose of reselling or otherwise disposing of service supplied Customer.

Proposed Rate
6. USE OF SERVICE:
Service is supplied directly to Customer through Company's own meter and is to be used by Customer only for the purposes specified in and in accordance with the provisions of the Service Agreement and applicable Rate Schedule. Service is for Customer's use only and under no circumstances may Customer or Customer's agent or any other individual, association or corporation install meters for the purpose of reselling service supplied Customer to any other individual, association, or corporation on Customer's premises or for use on any other premises. This does not preclude Customer from allocating Company's billing to Customer to any other individual, association, or corporation provided the sum of such allocations does not exceed Company's billing.

Service Regulations Section V – Metering

Present Rate
Each month the Company will monitor the usage of each customer according to the following procedure:
1. The customer's monthly usage is monitored through a "hi-lo" review process. An estimating factor is utilized to provide an expected level of usage. The estimating factor considers the customer's past usage and current variables, such as weather.
2. The actual usage is compared to an estimate based on the previous month's usage, an estimate based on the usage from the same month, one year previous, and an estimate based on the usage from the same month, two years previous.

Proposed Rate
Each month the Company will monitor the usage of each customer according to the following procedure:
1. The customer's monthly usage is monitored through a "hi-lo" review process that will incorporate customer past usage and other related information to provide an expected level of usage.

Service Regulations Section VI – Billing and Payment

Present Rate
The following text is removed from the tariff sheet, "If bills are rendered electronically then a charge not to exceed $0.25 per usage may be assessed."

Proposed Rate
The following description of the budget bill plan is added to the tariff sheet.
<u>Budget Billing Plan Description:</u>
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.

Quarterly Plan:
- The Quarterly Plan provides 3 months of equal payments starting by using 12 months of customer's usage, dividing the usage by 12, and using the result to calculate the bill.
- However, to prevent a settle-up month, reviews occur after 3, 6, 9, and 12 months on the plan and continue every 3 months thereafter.

- The budget bill amount is changed as needed after each review. The change is automatic and the customer does not need to contact Company.
- A bill message is sent after each review with a new bill amount if the budget bill amounts compared to the actual bill amounts exceeds a Company set threshold.

Full Requirements Aggregation Service - Rate FRAS

Present Rate

UPSTREAM CAPACITY REQUIREMENTS

Suppliers participating in the Company's firm transportation program must secure their own upstream pipeline capacity required to meet Supplier's Rate FT-L pool peak day requirements. Due to the physical configuration of the Company's system, and certain upstream interstate pipeline facilities, and to enable the Company to comply with lawful interstate pipeline tariffs and/or to maintain the Company's system integrity, during the months of December, January, and February, the Company reserves the right to direct Supplier to proportionally deliver, with respect to the Systems' (the Duke Energy Ohio and Duke Energy Kentucky, Inc. integrated operating system) northern and southern interstate pipeline interconnects, the Supplier's daily pool requirements. In those instances where the pool operator delivers gas into the Duke Energy Ohio pipeline system and Duke Energy Ohio then delivers said gas to Duke Energy Kentucky, Inc. for delivery to the pool operator's customers located in Kentucky, the pool operator shall pay Duke Energy Kentucky, Inc. for charges from Duke Energy Ohio for delivery of said gas, at the FERC approved rate.

OPERATIONAL FLOW ORDERS:

Over-deliveries

(1) Over-deliveries by Supplier will be confiscated by the Company and used for its general supply requirements, without compensation to Supplier,

Proposed Rate

DEFINITIONS:

"Under-Deliveries" or "Negative Imbalance Volume" is the amount by which the sum of all volumes actually delivered to the Pool customers during the period exceeds the sum of the volumes made available by supplier for redelivery by the Company to the Pool during the same period.

UPSTREAM CAPACITY REQUIREMENTS

Suppliers participating in the Company's firm transportation program must secure their own upstream pipeline capacity required to meet Supplier's Rate FT-L pool peak day requirements. Due to the physical configuration of the Company's system, and certain upstream interstate pipeline facilities, and to enable the Company to comply with lawful interstate pipeline tariffs and/or to maintain the Company's system integrity, the Company reserves the right to direct Supplier to proportionally deliver, with respect to the Systems' (the Duke Energy Ohio and Duke Energy Kentucky, Inc. integrated operating system) northern and southern interstate pipeline interconnects, the Supplier's daily pool requirements. In those instances where the pool operator delivers gas into the Duke Energy Ohio system and Duke Energy Ohio then delivers said gas to Duke Energy Kentucky, Inc. for delivery to the pool operator's customers located in Kentucky, the pool operator shall pay Duke Energy Kentucky, Inc. for charges from Duke Energy Ohio for delivery of said gas, at the FERC approved rate.

OPERATIONAL FLOW ORDERS:

Over-deliveries

(1) Over-deliveries will be cashed out to the Supplier at the lowest cost of gas available to Company on the date of non-compliance, plus transportation and fuel charges to the Company's city gate; and

Spark Spread Interruptible Transportation Rate - Rate SSIT

Proposed Rate

This tariff is hereby cancelled and withdrawn. Any references on individual tariffs were deleted.

Pooling Service for Interruptible Gas Transportation - Rate AS

Proposed Rate

The name of this rate is proposed as Rate AS - Aggregation Service for Interruptible Gas Transportation.

Gas Trading Service - Rate GTS

Present Rate

Daily imbalance trades or transfers must be made within four (4) business days from the date that the trade or transfer applies. Monthly imbalance trades or transfers must be completed within four (4) business days following the end of the month.

Proposed Rate

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.

Accelerated Service Replacement Program Rider - Rider ASRP

Present Rate

The charges for the respective gas service schedules for the revenue month beginning January 2018 are:

Rate RS, Residential Service	$1.80/month
Rate GS, General Service	$1.78/month
Rate DGS, Distributed Generation Service	$0.00045/CCF
Rate FT-L, Firm Transportation Service – Large	$0.00045/CCF
Rate IT, Interruptible Transportation Service	$0.00039/CCF
Rate SSIT, Spark Spread Interruptible Transportation Rate	$0.00039/CCF

Proposed Rate

This tariff is proposed to be incorporated into base rates listed above. This tariff is hereby cancelled and withdrawn.

Curtailment Plan for Management of Available Gas Supplies

Present Rate

Available in entire territory to which tariff Ky.P.S.C. Gas No. 1 applies.

Proposed Rate

Available in entire territory to which tariff Ky.P.S.C. Gas No. 2 applies.

IMPACT OF PROPOSED RATES

The foregoing proposed rates designed to recover Duke Energy Kentucky's revenue deficiency reflect an increase in gas revenues of approximately $10.5 million or 11.1% to Duke Energy Kentucky. The estimated amount of this increase per customer class is as follows:

Customer Class	Revenue Increase Proposed	%
Rate RS – Residential Service	$ 6,448,449	9.8%
Rate GS – Commercial Service	$ 2,041,693	10.3%
Rate GS – Industrial Service	$ 131,405	11.3%
Rate GS – Other Public Authority Service	$ 251,299	11.3%
Rate FT-L – Firm Transportation Service	$ 1,545,442	30.6%
Rate IT – Interruptible Transportation Service	$ 123,931	8.1%
Rate GTS – Gas Trading Service*	$0	0.0%
Rate IMBS – Interruptible Monthly Balancing Service*	$0	0.0%
Rider WNA – Weather Normalization Adjustment*	$0	0.0%
Charge for Reconnection of Service*	$0	0.0%
Rate MPS – Meter Pulse Service*	$0	0.0%

*The revenue deficiency is not allocated to these items.

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

Customer Class	Average Monthly CCF	Average Monthly Bill Increase Proposed	% Increase
Rate RS – Residential Service	53	$ 5.78	10.2%
Rate GS – Commercial Service	336	$ 26.08	10.3%
Rate GS – Industrial Service	683	$ 52.27	11.3%
Rate GS – Other Public Authority Service	733	$ 56.04	11.3%
Rate FT-L – Firm Transportation Service	23,202	$ 1,370.07	30.6%
Rate IT – Interruptible Transportation Service	56,060	$ 469.22	8.1%
Rate GTS – Gas Trading Service**	NA	$0	0.0%
Rate IMBS – Interruptible Monthly Balancing Service**	NA	$0	0.0%
Rider WNA – Weather Normalization Adjustment	NA	$0	0.0%
Charge for Reconnection of Service**	NA	$0	0.0%
Rate MPS – Meter Pulse Service**	NA	$0	0.0%

**These items are optional services not necessarily applicable to customer's average monthly bill.

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.

A person may submit a timely written request for leave to intervene to the Public Service Commission, P.O. Box 615, Frankfort, Kentucky 40602, establishing the grounds for the request including the status and interest of the party. If the Commission does not receive a written request for intervention within thirty (30) days of the initial publication of the notice, the Commission may take final action on the application. Comments regarding the application can be submitted to the Public Service Commission through its website http://psc.ky.gov or by mailing a copy to the Public Service Commission, P.O. Box 615, Frankfort, Kentucky 40602.

Customers may obtain copies of the application and other filings made by the Company by emailing DEKInquiries@duke-energy.com or by telephone at (513) 287-4356. 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 Duke Energy Kentucky offices: 4580 Olympic Boulevard, 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
4580 OLYMPIC BOULEVARD
ERLANGER, KENTUCKY 41018
(513) 287-4356

Duke Energy Kentucky
Cost of Service Study Customer Components and Customer Charge Calculations

		(A)	(B)	(C) = (A) / (B)	(D)
Line	Rate	COSS Customer Component	Test Period Customer Bills	COSS Supported Customer Charge	Proposed Customer Charge
1	RS	$ 27,323,239	1,110,274	$ 24.61	$ 17.50
2	GS	$ 4,349,513	85,245	$ 51.02	$ 50.00
3	FT-L	$ 234,315	1,128	$ 207.73	$ 430.00
4	IT	$ 130,843	264	$ 495.62	$ 430.00

Duke Energy Kentucky
Example Calculation of WNA Rider Adjustment for Rate RS Customer

Line	Calculation Inputs:		Values & Calculations
1	CCF Consumption		100
2	Actual Billing Period HDD (ADD)*		800
3	Normal Billing Period HDD (NDD)*		575
4	Rate RS Class Parameters:		
5	BL - Base Load		1.106333
6	HSF - Heat Sensitivity Factor		0.015283
7	Proposed Rate RS Distribution Charge (R)	$	0.48677
	Calculations:		
8	NDD - ADD		(225.00)
9	HSF * (NDD - ADD)		(3.44)
10	HSF * ADD		12.23
11	BL + (HSF * ADD)		13.33
12	Line 9 / Line 11		(0.26)
13	WNA = R * Line 12		-0.12554
14	Customer Revenue Adjustment =		
15	WNA (Line 13) * CCF (Line 1)	$	(12.55)

*HDD - Heating Degree Days

Duke Energy Kentucky, Inc.
Rider WNA Delivery Charge/Credit Estimate

Line	Month	Rate RS CCF	Rate GS CCF	NDD	ADD	Rate RS WNA	Rate RS WNA Revenue Adjustment	Rate GS Calculated WNA	Rate GS WNA Revenue Adjustment	Total WNA Revenue Adjustment
1	1/1/15	13,307,333	7,088,725	857.5	859.8	(0.00)	$ (12,378)	(0.00)	$ (3,505)	$ (15,883)
2	2/1/15	13,138,816	7,440,806	786.4	894.5	(0.04)	$ (546,356)	(0.02)	$ (164,691)	$ (711,047)
3	3/1/15	12,869,925	6,780,534	595.2	823.0	(0.09)	$ (1,218,247)	(0.05)	$ (340,670)	$ (1,558,917)
4	4/1/15	5,279,541	2,948,852	314.2	277.0	0.04	$ 209,716	0.02	$ 58,695	$ 268,411
5	5/1/15	2,145,884	1,292,626	95.6	71.5					
6	6/1/15	1,330,390	995,102	14.6	13.7					
7	7/1/15	1,119,383	849,428	0.2	-					
8	8/1/15	991,511	780,036	-	-					
9	9/1/15	1,028,565	804,187	2.6	0.1					
10	10/1/15	1,351,520	1,011,491	67.4	42.6					
11	11/1/15	2,918,712	1,657,886	277.3	181.5	0.14	$ 409,973	0.07	$ 112,799	$ 522,772
12	12/1/15	6,400,917	3,403,156	619.4	424.9	0.15	$ 931,567	0.07	$ 255,143	$ 1,186,710
13	1/1/16	10,446,693	5,484,138	861.0	699.9	0.08	$ 810,848	0.04	$ 224,576	$ 1,035,424
14	2/1/16	11,349,788	6,061,511	782.1	753.4	0.01	$ 146,322	0.01	$ 41,346	$ 187,668
15	3/1/16	7,533,309	4,172,021	595.5	442.9	0.11	$ 830,236	0.06	$ 237,409	$ 1,067,645
16	4/1/16	4,711,582	2,434,914	318.0	259.2	0.07	$ 310,689	0.03	$ 80,063	$ 390,752
17	5/1/16	2,217,072	1,339,953	97.6	86.4					
18	6/1/16	1,444,960	951,544	15.4	22.0					
19	7/1/16	1,029,890	799,125	0.3	-					
20	8/1/16	923,072	659,542	-	-					
21	9/1/16	964,659	741,210	2.3	0.1					
22	10/1/16	1,086,213	818,296	64.6	14.9					
23	11/1/16	2,575,105	1,506,231	274.7	156.1	0.19	$ 497,459	0.09	$ 139,058	$ 636,517
24	12/1/16	8,602,222	4,473,290	608.6	603.2	0.00	$ 25,636	0.00	$ 6,990	$ 32,626
25	1/1/17	11,832,981	6,443,107	818.9	752.2	0.03	$ 356,029	0.02	$ 102,562	$ 458,591
26	2/1/17	8,738,793	4,682,961	792.1	566.0	0.13	$ 1,151,615	0.07	$ 322,635	$ 1,474,250
27	3/1/17	7,298,320	3,882,239	610.0	448.7	0.12	$ 840,866	0.06	$ 231,116	$ 1,071,982
28	4/1/17	4,413,021	2,575,771	324.8	243.4	0.10	$ 423,425	0.05	$ 122,643	$ 546,068
29	5/1/17	2,235,095	1,311,712	108.3	71.8					
30	6/1/17	1,274,547	902,299	16.9	13.3					
31	7/1/17	1,039,435	754,572	0.3	-					
32	8/1/17	923,611	730,882	-	-					
33	9/1/17	1,087,491	850,118	1.9	3.4					
34	10/1/17	1,121,891	830,690	60.0	12.1					
35	11/1/17	4,315,235	2,489,239	266.2	276.5	(0.01)	$ (47,414)	(0.01)	$ (13,703)	$ (61,117)
36	12/1/17	8,866,438	4,820,440	593.5	586.0	0.00	$ 37,283	0.00	$ 10,614	$ 47,897
37	1/1/18	15,370,338	8,471,131	859.6	1,070.7	(0.07)	$ (1,056,182)	(0.04)	$ (311,523)	$ (1,367,705)
38	2/1/18	11,758,532	6,359,524	787.5	713.6	0.03	$ 411,227	0.02	$ 117,430	$ 528,657
39	3/1/18	8,139,689	4,630,421	606.5	501.4	0.07	$ 554,588	0.04	$ 163,970	$ 718,558
40	4/1/18	7,782,843	4,507,496	327.4	476.6	(0.10)	$ (787,115)	(0.05)	$ (236,309)	$ (1,023,424)
41	5/1/18	2,964,733	1,809,095	99.9	122.5					
42										
43	Winter									
44	2015-2016						$ 3,439,635		$ 951,336	$ 4,390,971
45	2016-2017						$ 3,295,030		$ 925,004	$ 4,220,034
46	2017-2018						$ (887,613)		$ (269,521)	$ (1,157,134)

WNA RS Factors:	
BL	[illegible]
HSF	[illegible]
R	[illegible]

WNA GS Factors:	
BL	[illegible]
HSF	[illegible]
R	[illegible]

Duke Energy Kentucky, Inc.
Calculation of Gas Service Reconnection Cost

Base Labor		$33.64	
Unproductive (time away - vacations, etc)	23.4%	$7.87	Loads on Base - direct labor
Incentives (annual bonuses)	5.9%	$2.43	Loads on Base plus Unprod
Subtotal		$10.30	
Fringes (benefits - health, retirement, etc)	33.2%		
Payroll Tax	6.2%		
Subtotal	39.3%	17.29	Loads on Base plus Unprod plus Incentive
Fleet (cost of vehicles)	9.4%	3.17	Loads on Base - direct labor
Loaded Labor w/ Fleet		$64.40	
Indirects (allocated costs of support functions)	61.1%	$39.32	Load on Loaded Labor
Total Cost Per Hour		$103.72	

	Approximate Hours	Cost
Gas Service Reconnection	1.00	$103.72
Contracted Rate for Gas Reconnection (Seasonal)		$90.25
Proposed Gas Service Reconnection Charge:		$75.00

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:	$ 126.00
4	Dual Lead Metretek Pulser:	$ 162.00
5	Average Pulser Cost	$ 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	$ 315.00
10	Weather-proof Box	$ 100.00
11	Total Average ISB Cost:	$ 415.00
12	Total Meter Pulse Equipment:	$ 559.00
13	Tariff Sheet Value Proposed:	[redacted]
14	Meter Index if needed (1 or 2 options):	
15	Life Lube Rotary Index	$ 535.00
16	Life Lube Rotary Index Conversion Kit	$ 588.00
17	Average Meter Index Cost	$ 561.50
18	Tariff Sheet Value Proposed:	[redacted]

Duke Energy Kentucky
Rate IMBS Monthly Imbalance Charge Rate Calculation

Line No.	Charges for Daily Balancing		Cost	
1	Demand Charges	$	318,214.20	$
2	Commodity Charges	$	45,928.12	$
3	Total	$	364,142.32	$
4	Rate IT Throughput (Mcf)		3,396,774	Mcf
5	Daily Balancing Cost (All Options) - $/Mcf	$	0.1072	per Mcf
	Carry-Over Amount Charges			
6	Option 1:			
7	Columbia Gas FSS Cost	$	4,046.86	$
8	Throughput (Mcf)		2,408,845	Mcf
9	Charge for Monthly Carry-Over - Option 1	$	0.0017	per Mcf
	Total Charge for Option 1	$	0.1089	per Mcf
10	Option 2:			
11	Columbia Gas FSS Cost	$	196.80	$
12	Throughput (Mcf)		100,000	Mcf
13	Charge for Monthly Carry-Over - Option 2	$	0.0020	per Mcf
	Total Charge for Option 2	$	0.1092	per Mcf
14	Option 3:			
15	Columbia Gas FSS Cost	$	2,513.29	$
16	Throughput (Mcf)	$	987,929	Mcf
17	Charge for Monthly Carry-Over - Option 3	$	0.0025	per Mcf
	Total Charge for Option 3	$	0.1097	per Mcf
18	Proposed Charge for a Single Option	$	0.1097	per Mcf