Duke Energy Kentucky
Case No. 2009-00202
Forecasted Test Period Filing Requirements
Table of Contents

Duke Energy Kentucky
Case No. 2009-00202
Forecasted Test Period Filing Requirements
Table of Contents

Vol. #	Tab #	Filing Requirement	Description	Sponsoring Witness
1	15	807 KAR 5:001 Section 10 (4)(c)	Except for sewer utilities, applicants with more than twenty (20) customers affected by the proposed general rate adjustment shall give the required notice by one (1) of the following methods: 1. A typewritten notice mailed to all customers no later than the date the application is filed with the commission; 2. Publishing the notice in a trade publication or newsletter which is mailed to all customers no later than the date on which the application is filed with the commission; or 3. Publishing the 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 within seven (7) days of the filing of the application with the commission.	Julia S. Janson
1	16	807 KAR 5:001 Section 10 (4)(d)	If notice is published, an affidavit from the publisher verifying that the notice was published, including the dates of the publication with an attached copy of the published notice, shall be filed with the Commission no later than forty-five (45) days of the filed date of the application.	Julia S. Janson
1	17	807 KAR 5:001 Section 10 (4)(e)	If notice is mailed, a written statement signed by the utility's chief officer in charge of Kentucky operations verifying the notice was mailed shall be filed with the Commission no later than thirty (30) days of the filed date of the application.	Julia S. Janson
1	18	807 KAR 5:001 Section 10 (4)(f)	All utilities, in addition to the above notification, shall post a sample copy of the required notification at their place of business no later than the date on which the application is filed which shall remain posted until the commission has finally determined the utility's rates.	Julia S. Janson
1	19	807 KAR 5:001 Section 10 (5)	Notice of hearing scheduled by the commission upon application by a utility for a general adjustment in rates shall be advertised by the utility by newspaper publication in the areas that will be affected in compliance with KRS 424.300.	Julia S. Janson
1	20	807 KAR 5:001 Section 10 (8)(a)	Financial data for forecasted period presented as pro forma adjustments to base period.	Robert M. Parsons, Jr.
1	21	807 KAR 5:001 Section 10 (8)(b)	Forecasted adjustments shall be limited to the 12 months immediately following the suspension period.	Robert M. Parsons, Jr.
1	22	807 KAR 5:001 Section 10 (8)(c)	Capitalization and net investment rate base shall be based on a 13 month average for the forecasted period.	Robert M. Parsons, Jr.

Duke Energy Kentucky
Case No. 2009-00202
Forecasted Test Period Filing Requirements
Table of Contents

Duke Energy Kentucky
Case No. 2009-00202
Forecasted Test Period Filing Requirements
Table of Contents

Vol. #	Tab #	Filing Requirement	Description	Sponsoring Witness
			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.	
1	32	807 KAR 5:001 Section 10 (9)(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.	Gary J. Hebbeler
1	33	807 KAR 5:001 Section 10 (9)(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.	Stephen R. Lee Stephen G. De May #6, #13, #16 & #17 Not applicable
1	34	807 KAR 5:001 Section 10 (9)(i)	Most recent FERC or FCC audit reports.	Brenda R. Melendez
1	35	807 KAR 5:001 Section 10 (9)(j)	Prospectuses of most recent stock or bond offerings.	Stephen G. De May
1	36	807 KAR 5:001 Section 10 (9)(k)	Most recent FERC Form 1 (electric), FERC Form 2 (gas), or the Automated Reporting Management Information System Report (telephone) and PSC Form T (telephone).	Brenda R. Melendez
2	37	807 KAR 5:001 Section 10 (9)(l)	Annual report to shareholders or members and statistical supplements for the most recent 5 years prior to application filing date.	Stephen G. De May
2	38	807 KAR 5:001 Section 10 (9)(m)	Current chart of accounts if more detailed than Uniform System of Accounts charts.	Brenda R. Melendez

Duke Energy Kentucky
Case No. 2009-00202
Forecasted Test Period Filing Requirements
Table of Contents

Duke Energy Kentucky
Case No. 2009-00202
Forecasted Test Period Filing Requirements
Table of Contents

Duke Energy Kentucky
Case No. 2009-00202
Forecasted Test Period Filing Requirements
Table of Contents

Duke Energy Kentucky
Case No. 2009-00202
Forecasted Test Period Filing Requirements
Table of Contents

STANDARD FILING REQUIREMENT SCHEDULES

KENTUCKY PUBLIC SERVICE COMMISSION

GAS CASE NO. 2009-00202

DATE: July 1, 2009

GENERAL APPLICATION FOR CHANGE IN
GAS RATES BEFORE KENTUCKY PUBLIC
SERVICE COMMISSION

NAME: DUKE ENERGY KENTUCKY
ADDRESS: 1697-A MONMOUTH STREET
NEWPORT, KENTUCKY 41071

MAILING
ADDRESS: P. O. BOX 960
CINCINNATI, OHIO 45201

TELEPHONE: AREA CODE 513 NUMBER 419-5908

COMPANY OFFICIAL TO BE CONTACTED
PERTAINING TO RATE CASE MATTERS William Don Wathen Jr.

FILING DATE: July 1, 2009

ATTORNEYS FOR APPLICANT:

NAME: Rocco D'Ascenzo

ADDRESS: P. O. Box 960
Cincinnati, Ohio 45202
TELEPHONE: (513) 419-1852

* * * FOR COMMISSION USE ONLY * * *

DATE RECEIVED BY COMMISSION ________________

DOCKET NUMBER ASSIGNED ____________________

RECEIVED BY __________________________________

DATE ACCEPTED ______________________________

ACCEPTED BY _________________________________

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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

CASE NO. 2009-00202

FILING REQUIREMENTS

VOLUME 9

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN ADJUSTMENT	)	
OF GAS RATES OF	)	CASE NO. 2009-00202
DUKE ENERGY KENTUCKY, INC.	)	

DIRECT TESTIMONY OF

JULIA S. JANSON

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

July 1, 2009

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TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Julia S. Janson, and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

Q. WHAT IS YOUR POSITION WITH DUKE ENERGY KENTUCKY, INC.?

A. I am President of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company). Duke Energy Kentucky is a wholly-owned subsidiary of Duke Energy Ohio, Inc. (Duke Energy Ohio), and Duke Energy Ohio's parent company is Duke Energy Corporation (Duke Energy).

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

A. I earned a Bachelor of Arts degree in American Studies from Georgetown College in Georgetown, Kentucky. I earned my Juris Doctor degree from the University of Cincinnati, College of Law. I am a member of the Ohio Bar and the Kentucky Bar.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A. My current position is President, Duke Energy Ohio and Duke Energy Kentucky. I previously served as Senior Vice President of Ethics and Compliance, and Corporate Secretary for Duke Energy, where I directed Duke Energy's ethics and compliance program. Prior to that, I served as Corporate Secretary and Chief Compliance Officer for Cinergy Corp. (Cinergy), where I directed Cinergy's corporate compliance program. I was appointed Chief Compliance Officer in 2004 and Corporate Secretary in 2000. From 1998 to 2004, I served as Senior Counsel, providing advice on executive compensation, benefits, transactions, corporate governance, securities, and general corporate matters. From 1996 to 1998, I served as Counsel for Cinergy, providing research, advice and support for divestitures, mergers and acquisitions, and numerous internal business clients including investor relations, shareholder services, corporate communications and government and regulatory affairs. I also served as corporate counsel to the international business unit. I was Manager of Investor Relations for Cinergy from 1995 to 1996. Prior to joining Cinergy, I began my corporate career in 1987 as a law clerk with The Cincinnati Gas & Electric Company (CG&E) and began full-time employment with CG&E as Supervisor of Securities Processing and Transfer Agent for CG&E common and preferred stock, after which I was named Corporate Attorney. In addition, I was a member of the legal team responsible for completing the merger of CG&E and PSI Energy, Inc., which formed Cinergy Corp. in 1994. Before joining CG&E, I served as a law clerk with Adams, Brooking, Stepner, Wolterman & Dusing in Covington, Kentucky.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. As President of Duke Energy Kentucky, I am responsible for ensuring that our customers continue to have access to safe, reliable, and reasonably-priced gas and electric service, and that these services are provided in accordance with applicable federal and state laws and regulations.

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

A. My testimony provides an overview of Duke Energy Kentucky's corporate and business structure. I next discuss the reasons for the relief Duke Energy Kentucky seeks in this proceeding, namely, Duke Energy Kentucky's need for an increase in gas delivery-related rates.

In describing our delivery responsibility, I will discuss how the timely and constructive regulatory treatment we are seeking from this Commission will enable us to continue to maintain high levels of customer satisfaction by providing our customers with the reasonably-priced, reliable service they have come to expect. I support Filing Requirements (FR) 8(1), 8(2), 10(1)(b)(2) through 10(1)(b)(6), 10(1)(b)(9), and 10(4). Additionally, I discuss the existing programs to achieve improvements in efficiency and productivity and the purpose of each program, as required by 807 KAR 5:001 Section 10(9)(a). Finally, I provide the management statement of attestation, required by 807 KAR 5:001 Section 10(9)(e), concerning the forecasted financial data.

II. OVERVIEW OF THE DUKE ENERGY CORPORATION AND BUSINESS STRUCTURE

Q. PLEASE GENERALLY DESCRIBE THE DUKE ENERGY CORPORATE AND BUSINESS STRUCTURE.

A. To more fully understand how Duke Energy Kentucky serves its customers, it is helpful to understand Duke Energy's corporate and business structure. Duke Energy is a holding company, formerly named Duke Energy Holding Corp., and was formed in connection with the merger of the former Duke Energy Corporation, a North Carolina corporation, and Cinergy, which was consummated in April 2006.

Duke Energy is a Delaware corporation and, following the merger, organized into three principal business segments, US Franchised Electric and Gas (USFE&G), Commercial Power, and Duke Energy International (DEI). USFE&G consists of Duke Energy's regulated generation and its electric and gas transmission and distribution systems. Its generation portfolio is a diverse mix of fuel sources — coal, oil/natural gas, nuclear and hydroelectric. USFE&G is Duke Energy's largest business segment. USFE&G includes the utility operating companies Duke Energy Carolinas, LLC (Duke Energy Carolinas), which operates in North and South Carolina, Duke Energy Kentucky, Duke Energy Ohio and Duke Energy Indiana, Inc. (Duke Energy Indiana).

Commercial Power owns, operates and manages power plants, located primarily in the Midwest. Commercial Power also includes Duke Energy Generation Services (DEGS), which develops, owns and operates generation sources (including wind assets) that serve large energy consumers, municipalities, utilities and industrial facilities.

DEI operates and manages power generation facilities located in the Central and South American countries of Argentina, Brazil, Ecuador, El Salvador, Guatemala and Peru. DEI also owns equity investments in Saudi Arabia and Greece.

Duke Energy Kentucky is a regulated utility operating company that provides retail electric and natural gas services in six counties in Northern Kentucky. The actual services that Duke Energy Kentucky's gas customers receive, however, may be performed by Duke Energy Kentucky employees, by shared service employees or by employees of another affiliated company in accordance with approved service agreements.

Q. WHICH CORPORATE ENTITIES PROVIDE SERVICES FOR DUKE ENERGY KENTUCKY'S RETAIL GAS CUSTOMERS?

A. Our customers benefit from services provided by other Duke Energy affiliates that have entered into a services agreement to perform services for Duke Energy Kentucky. The Commission approved these services agreements in Case No. 2005-00228, involving the Duke Energy/Cinergy merger. Immediately following the merger, Duke Energy had two service companies, Duke Energy Shared Services, Inc. (DESS) formerly Cinergy Services, Inc., (Cinergy Services), and Duke Energy Business Services, LLC (DEBS). DESS was the services company located in the Midwest and provided administrative and operational services for Duke Energy Kentucky. DEBS was the services company located in North Carolina that provided administrative and operational services for Duke Energy Carolinas. As part of the continuing effort to achieve merger efficiencies, DEBS and DESS were consolidated in July 2008, with DEBS becoming the sole service company. Duke Energy Kentucky witness Mr. David L. Doss describes these business arrangements and the service agreements in more detail in his testimony.

Q. HOW WILL DUKE ENERGY KENTUCKY'S CUSTOMERS KNOW WHICH LEGAL ENTITY IS PROVIDING SERVICE?

A. Our customers in Kentucky receive all of their utility services from Duke Energy Kentucky. The legal entity structure and relationships that I have described (and that Mr. Doss describes in more detail in his testimony) are essentially invisible and seamless to our retail natural gas customers in Kentucky. In other words, our Kentucky customers continue to and should expect to receive reliable, adequate, and reasonably-priced gas service from Duke Energy Kentucky without regard to how the Company is structured or organized to provide those services.

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY AND ITS GAS BUSINESS.

A. Duke Energy Kentucky serves a relatively densely-populated territory that, though not heavily industrialized, consists of a fairly diverse mix of industrial customers. Duke Energy Kentucky currently provides natural gas distribution service to approximately 96,000 customers in Boone, Campbell, Gallatin, Grant, Kenton and Pendleton counties in Northern Kentucky. The Company also owns, operates, and maintains approximately 1,425 miles of gas mains on its natural gas distribution system.

III. <u>DUKE ENERGY KENTUCKY'S NEED FOR AN INCREASE IN DISTRIBUTION-RELATED GAS RATES</u>

A. <u>OVERVIEW OF DUKE ENERGY KENTUCKY'S RATE INCREASE REQUEST</u>

Q. PLEASE BRIEFLY DESCRIBE WHY DUKE ENERGY KENTUCKY REQUIRES AN INCREASE IN ITS DISTRIBUTION-RELATED GAS RATES AT THIS TIME.

A. The incremental return, depreciation, and property taxes associated with plant invested through the Company's accelerated main replacement program (AMRP) comprises the largest share of Duke Energy Kentucky's proposed rate increase. Duke Energy Kentucky has not been recovering revenue requirements associated with its incremental AMRP investment since the time of the last gas rate case. This is because of the pending appeal of Rider AMRP discussed in more detail below. The inability to adjust Rider AMRP has left the Company well short of recovering its costs of providing gas distribution service to Duke Energy Kentucky's customers. In addition, volumetric sales on Duke Energy Kentucky's gas distribution system have actually declined and, consequently, exacerbated the problem of under-recovering full costs. These factors, combined with increases in other costs of providing gas service, compel Duke Energy Kentucky to request the increase proposed in this proceeding. Duke Energy Kentucky has accordingly filed the instant proceeding to establish new base rates for the Company's forecasted test period revenue requirement, as discussed by Duke Energy Kentucky witness Mr. Robert M. Parsons.

Q. PLEASE BRIEFLY DESCRIBE THE DEVELOPMENTS WITH RIDER AMRP SINCE THE COMPANY'S LAST GAS RATE CASE.

A. Duke Energy Kentucky last increased its gas delivery base rates in 2005 pursuant to a Commission Order in Case No. 2005-00042. In that case, Duke Energy Kentucky filed for and received approval for recovery of the costs of its AMRP. At that time, the Commission permitted Duke Energy Kentucky to roll its AMRP investment into base rates and reset the Rider. The Commission also directed Duke Energy Kentucky to time the filing of its next gas base rate case to coincide with the completion of the AMRP program in 2010. Duke Energy Kentucky witness Mr. Gary J. Hebbeler discusses the success of the AMRP the progress of the program, as well as, other safety and reliability initiatives in his testimony.

Since approval of Duke Energy Kentucky's rates, in Case No. 2005-00042, Duke Energy Kentucky has continued to invest in the facilities necessary to provide highly-reliable, yet cost effective, gas delivery services to our customers. Comparing the rate base established in that proceeding (based on a forecasted test period ending in September 2006) to the rate base used in the forecasted test period in this case (based on a forecasted test period ending in January 2011), Duke Energy Kentucky's investment in its gas distribution system is projected to increase by over 40%, mostly attributable to the AMRP program.

Importantly, the Kentucky Attorney General has appealed the Commission's decisions approving the Rider AMRP mechanism and the annual Rider AMRP increases. The Rider was suspended in 2007 following a decision in the Franklin Circuit Court that found the Commission's approval of the Rider

AMRP improper. Duke Energy Kentucky and the Commission appealed the Circuit Court decision. On appeal, the Court found that the statute authorizing the AMRP Rider was properly enacted but did not agree that the Commission had the authority to approve rider recovery before the statute became effective in 2005. The case is currently pending a decision by the Kentucky Supreme Court for discretionary review. Accordingly, Duke Energy Kentucky has not recovered any incremental capital investment dollars through Rider AMRP since the Company's last rate case. Given this under recovery relating to Rider AMRP, Duke Energy Kentucky based the instant case on a forecasted test period for the twelve-month period ending January 31, 2011, to coincide with the completion of the AMRP initiative. Duke Energy Kentucky requests that the Commission approve its past and projected investment in its AMRP as part of base rates.

Q. PLEASE GIVE AN OVERVIEW OF DUKE ENERGY KENTUCKY'S CURRENT RETAIL GAS DELIVERY RATES.

A. Duke Energy Kentucky's average gas delivery rates (including the cost of gas) compare favorably to both national average rates and Kentucky investor-owned utility average gas delivery rates. According to the December, 2008 Bill Comparison Report provided by the American Gas Association, Duke Energy Kentucky's gas delivery rates for residential, commercial, and industrial customer classes were lower than all other Kentucky investor-owned utilities reported in the survey.

Q. PLEASE GIVE A BRIEF OVERVIEW OF DUKE ENERGY KENTUCKY'S PROPOSED GAS DELIVERY RATE INCREASE.

A. Duke Energy Kentucky proposes to increase its gas delivery base rates so as to increase its annual revenues for its gas delivery business by approximately $17.5 million. This represents an average aggregate rate increase of approximately 14% on a total gas bill basis over the average gas delivery rates currently in effect. This rate increase is necessary in order to allow Duke Energy Kentucky to recover its costs for providing safe, reliable gas-delivery service, plus a fair return on its investment in gas-delivery facilities.

Duke Energy Kentucky used a forecasted test period utilizing projected 2010 and 2011 budget information and certain adjustments as a basis for the forecasted test period ending January 31, 2011, as discussed by Duke Energy Kentucky witness Stephen R. Lee. The Company selected a forecasted test period because it continues to invest heavily in its AMRP and the forecasted test period will enable Duke Energy Kentucky to have all AMRP-related plant in service and avoid some degree of lag in recovery of these costs, and gain more certainty in recovery of its AMRP investment, as these expenditures will be reflected in base rates through the end of the forecasted test period.

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S GAS DELIVERY CAPITAL INVESTMENTS SINCE THE COMPANY'S LAST GENERAL GAS RATE CASE.

A. Since its last general gas rate case, Duke Energy Kentucky has made substantial capital investments to its gas delivery systems. The valuation date in that case was September 30, 2006. From that date through January 31, 2011, these system investments are projected to total approximately $66 million for the AMRP, and

$6 million for the riser replacement program. Additionally, Duke Energy Kentucky has made the typical ongoing capital investments necessary to serve new customers, and to continue providing safe, reliable service to existing customers.

As of December 31, 2008, the AMRP investments in Duke Energy Kentucky's gas delivery distribution system have enabled Duke Energy Kentucky to replace approximately 172 miles of cast iron and bare steel mains and associated services. The projected AMRP investments in Duke Energy Kentucky's gas delivery distribution system for 2009 and 2010 will enable Duke Energy Kentucky to replace an additional approximately 31 miles of cast iron and bare steel mains and associated services. This will enable Duke Energy Kentucky to complete the AMRP on time per our original estimate. Mr. Hebbeler's testimony discusses these investments in our distribution system in more detail.

B. OVERVIEW OF DUKE ENERGY KENTUCKY'S GAS DELIVERY SYSTEM AND OPERATIONS

Q. PLEASE GIVE AN OVERVIEW OF DUKE ENERGY KENTUCKY'S OPERATIONS.

A. Duke Energy Kentucky is headquartered in Newport, Kentucky, with additional locations across the Ohio River in Cincinnati, Ohio. From these local offices, Duke Energy Kentucky directs the planning, construction, operation and maintenance of its gas delivery system. Mr. Hebbeler discusses Duke Energy Kentucky's Gas Operations in detail. Duke Energy Kentucky also provides electric service to approximately 134,000 customers in Boone, Campbell, Gallatin, Grant, Kenton and Pendleton counties in Northern Kentucky.

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

A. Duke Energy Kentucky's longstanding support for state and local economic development efforts, combined with Duke Energy Kentucky's reasonably-priced rates, have resulted in a number of Kentucky economic development successes in which the Company has played a role.

Duke Energy Kentucky's economic development staff has actively served on several committees of the Kentucky Association for Economic Development, including the new Marketing Committee. One of our staff serves on the newly-formed Horizon Certified Development Company's SBA loan committee, providing low-interest, fixed-rate financing for small businesses in Kentucky. Our economic development staff is also an active partner with the Tri-County Economic Development Corporation (Tri-ED), consisting of Boone, Kenton, and Campbell Counties. Our Vice President of Community Relations and Economic Development currently serves on the Tri-ED Board, having been appointed by the Boone County Judge Executive.

For the last ten years, Duke Energy and/or Cinergy have been named as having one of the "Top 10 Best" utility economic development programs by *Site Selection* magazine. Even more important to us, our surveys of local economic development officials indicate that they are highly satisfied (100% satisfaction rate) with Duke Energy Kentucky's economic development efforts and services.

We estimate that our cooperative efforts, along with state and local economic development officials, have contributed to the creation of nearly 25,000 Kentucky jobs and more than $2.2 billion of capital investment in Northern Kentucky since 1995.

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

A. Duke Energy Kentucky has made good corporate citizenship a priority by giving back to the communities we serve. Since 1994, our philanthropic affiliate, the Duke Energy Foundation and formerly the Cinergy Foundation, has contributed over $3.18 million to Northern Kentucky charitable organizations in the communities we serve. We strongly encourage a spirit of volunteerism among our employees, who contribute countless hours of volunteer time to support the many communities in which they live and work. Duke Energy Kentucky also supports heating assistance programs.

C. <u>OVERVIEW OF DUKE ENERGYKENTUCKY'S CUSTOMER SERVICE CHANNELS</u>

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S CUSTOMER SERVICE ACTIVITIES.

A. Duke Energy Kentucky strives to provide customers a variety of convenient methods to do business with us. Duke Energy Kentucky strives to manage and reduce its customer service costs by leveraging new technology and new customer service channels. Duke Energy Kentucky's customer service channels include:

- *Contact Centers* – Duke Energy Midwest (covering Kentucky, Ohio and Indiana) has approximately 80 customer service representatives in our Cincinnati, Ohio, call center and approximately 140 customer service representatives taking calls in the Plainfield, Indiana, call center. All of these representatives are linked as if one virtual call center and are all available to respond to calls from Kentucky customers. Our sourcing partner ERS, located in Atlanta, Georgia, and Birmingham, Alabama, takes approximately 40% of total agent call volume for the Midwest and these are predominantly credit calls. This achieves a lower overall cost structure and provides added means to deal with peak call volumes. For example, ERS provides us an additional set of agents we can activate fairly quickly at the onset of a major storm.
- *Business Service Center* – Our Business Service Center provides customer service and communications to our commercial, industrial, and governmental customers. The Business Service Center is staffed by skilled personnel with many years of quality field experience who respond to customers via telephone, e-mail, and fax. Additionally, Duke Energy Kentucky provides Customer Relationship Managers and Technical Service Engineers who meet with these customers in person as needed.
- *Pay Agents* – Pay agents are local authorized retailers or agents that accept Duke Energy Kentucky bill payments and transmit the data to our billing system on a daily basis. Our eight Duke Energy Kentucky pay agents allow customers to pay their bills at conveniently located businesses, many of which have extended hours.

- *Automated Phone Service* – This service allows customers to access information regarding their gas and/or electric service accounts from any touchtone telephone, 24 hours a day, seven days a week. Via automated phone service, customers can check the amount and due date of their current bill, verify the amount and date of their last payment, confirm the amount and due date to prevent disconnection for non-payment, pay by phone, make payment arrangements, or report a service outage. In 2008, Duke Energy Midwest's self-service Interactive Voice Response (IVR) handled approximately 1.3 million customer contacts – representing 24% of total call volume.

  In 2009, we will be rolling out a new IVR platform. The following are key elements to be provided in the new design:

  - Dynamic menu options - Customers will hear options most relevant to their needs (based on customer self-identification).
  - Enhanced outage reporting - Will enable us to provide additional information about the cause of a power outage and restoration times.
  - Spanish self-service applications.

- *Enhanced Web Functionality for Online Services* – Duke Energy Kentucky is offering enhanced web self-service functionality that includes new tools allowing customers to better analyze how external factors, such as weather, impact their energy usage. The tools also offer customers a sense of which appliances in their homes are likely driving their energy usage. They have the capability to pursue a more detailed energy audit or receive a personalized energy report. A similar set of tools, integrated with those on the web, have been made available to customer service representatives in the call centers so that they can provide this same information to customers. Other useful and timely information is available on the Duke Energy website, including how to manage bills during heating and cooling seasons, how to be safe around gas and electricity, information about rates and tariffs and more. Customers can identify ways to conserve energy, view the "Storm Center" to see the locations and number of electric outages during severe weather, submit online requests for tree trimming, and report street light outages.

D. OVERVIEW OF DUKE ENERGY KENTUCKY'S BILL MANAGEMENT AND BILL PAYMENT OPTIONS

Q. PLEASE GIVE AN OVERVIEW OF DUKE ENERGY KENTUCKY'S BILL MANAGEMENT AND BILL PAYMENT PROGRAMS.

A. Duke Energy Kentucky offers several optional bill management programs, designed to meet our customers' varied needs:

- *Budget Billing Program* – This program helps customers manage their monthly energy costs by setting a monthly billing amount based on an average annual cost. Under the "Quarterly" Budget Billing plan, we review the customer's account every three months and adjust the Budget Billing amount to better reflect actual energy use. This allows customers to avoid a twelfth month bill adjustment. Under the "Annual" Budget Billing plan, the customer's monthly payments remain the same each month and, in the twelfth month, the customer is billed or credited for any difference between actual usage and the total amount paid during the Budget Billing year. During the sixth month of the Annual plan, we review the customer's account and notify them with a bill message if the current Budget Billing amount needs to be adjusted up or down. The customer can notify us if they wish to change their Budget Billing amount at any time.

- *Adjusted Due Date* – This plan allows eligible customers to extend their normal billing due date up to ten days from their original due date. This enables customers to better align their due date with the date they receive their paycheck, pension, Social Security check, etc.
- *Extended Payment Agreements* – Duke Energy Kentucky offers extended payment plans to eligible customers who are having difficulty paying their entire bill by the due date. Residential customers may be eligible for one three-month agreement in a 12-month period. The customer must pay 1/3 of their current balance to start the agreement and the remainder is divided into 2 equal installments. The customer must also pay their current monthly charges or may choose to go on Budget Billing with the agreement.
- *WinterCare* – This energy assistance program is available to eligible Duke Energy Kentucky customers who need financial assistance with their gas and/or electric bill and is independently administered by the Northern Kentucky Community Action Commission. Eligibility is based upon need and does not necessarily follow government assistance guidelines.

Eligible customers can receive up to $300.00 in assistance with their utility bill. WinterCare is completely funded by Duke Energy Kentucky employees, customers, and shareholders. For 2008, Duke Energy Kentucky provided a $25,000 lump sum contribution and is matching $1.00 for every $1.00 donated, up to $25,000, providing for total funding of up to $50,000.

Duke Energy Kentucky also offers a number of bill payment options for customers, in addition to the traditional bill payment option via U.S. mail:

- *BillPayer 2000* – This program allows customers to have their bill payments automatically deducted from their checking account. A nominal transaction fee is assessed by the third-party vendor for this program.
- *Speedpay* – This program allows customers to make payments by electronic check or credit/debit card over the telephone or via the Internet. The third-party vendor charges a transaction fee for this program.
- *e-Bill* – This free online electronic payment option allows Duke Energy Kentucky customers to view and pay their gas and/or electric bills online. e-Bill offers two payment options: AutoPay (payments are automatically paid each month on the due date) and Pay Online (customers authorize bill payments online each month). All customer payments are electronically deducted from their personal checking account and/or money market account. Duke Energy Kentucky currently has approximately 23,272 customers enrolled in e-Bill.

E. CUSTOMER SATISFACTION

Q. HOW IS DUKE ENERGY KENTUCKY'S PERFORMANCE IN TERMS OF PROVIDING HIGH QUALITY CUSTOMER SERVICE?

A. We measure our customer satisfaction performance through multiple measurement tools: the J.D. Power annual gas utility residential customer satisfaction studies; and, our own surveys of residential, mass market, and large business customers.

J.D. POWER STUDIES

J.D. Power is well known for setting the standard for measurement of consumer opinion and customer satisfaction in many key industries. J.D. Power annually surveys gas utilities' residential customer satisfaction. Duke Energy Midwest participates in these annual studies.

The J.D. Power gas utility residential customer satisfaction study, established in 2001, calculates overall customer satisfaction based on six performance areas: (1) company image; (2) communications; (3) price and value; (4) billing and payment; (5) field service; and (6) customer service. For 2008, the most recent study for which results are available, J.D. Power measured residential customer satisfaction for the country's 60 large gas utilities, serving over 48 million customers. Since 2001, the results of the J.D. Power studies indicate that Duke Energy's Midwest Operations consistently deliver high-quality customer satisfaction.

DUKE ENERGY KENTUCKY – SPECIFIC CUSTOMER SURVEYS

In addition to the independent J.D. Power studies, our internal customer satisfaction measurements continue to reflect strong performance in meeting the needs of Duke Energy Kentucky customers. We regularly survey residential, mass market, and large business customers who have had a recent service contact with Duke Energy Kentucky.

RESIDENTIAL TRANSACTIONAL SURVEY

The transactional survey is conducted continuously using direct mail among a random sample of customers who have recently had interactions with Duke Energy Kentucky in one of three categories: service interruptions; turning on or turning off service; and, billing and payment inquiries. Each of these categories is one-third of the Transactional Satisfaction score. Survey results are compiled monthly. Customers are asked to rate their satisfaction with overall transaction on a scale of 1 to 5 and the percentage of customers who provide a 4 or 5 are included in the score. Duke Energy Kentucky's 2008 year-end score was 81.8%.

RESIDENTIAL AND SMALL BUSINESS RELATIONSHIP SURVEY

The Residential and Small Business Surveys are monthly studies conducted by Thoroughbred Research (Louisville, Kentucky) for a random sample of customers. Customers are contacted by telephone and asked to rate their overall satisfaction with Duke Energy Kentucky on a scale of 1 to 10. Duke Energy Kentucky's 2008 year-end score for residential customer satisfaction shows that 68.9% of surveyed residential customers gave the Company a raking of 8 or higher. Similarly, Duke Energy Kentucky's 2008 small business satisfaction survey indicates 64% of its small business customers gave the Company a satisfaction score of 8 or higher.

COMMUNITY LEADERS SURVEY

The Community Leaders Survey is an online survey. Respondents are e-mailed an invitation with a link to participate in the survey. The survey comprises Community leaders in tier 1 and 2 communities who have high or medium political or policy influence at the state, regional or local level. Tier 1 communities represent populations greater than 20,000. Tier 2 are those with a population range of 6,000 to 20,000. Duke Energy Kentucky's overall satisfaction score is measured as the percent of customers responding with an 8, 9, or 10 on a 10-point scale. Duke Energy Kentucky's 2008 score was 93.9%.

IV. BENEFITS OF THE DUKE/CINERGY MERGER

Q. HOW HAS THE DUKE/CINERGY MERGER BENEFITTED DUKE ENERGY KENTUCKY'S CUSTOMERS?

A. This merger combined two outstanding companies with a strong track record of reasonable rates, high customer satisfaction, and safe and reliable services. Duke Energy continues to build on the combined foundation of these two companies and better enables Duke Energy Kentucky to provide safe, reliable and reasonably-priced gas and electric service to its customers. Duke Energy Kentucky benefits from Duke Energy's strong financial and generation profile.

The increased scale and scope of operations resulting from the merger has strengthened new Duke Energy's balance sheet and financial flexibility, compared with the balance sheet and financial resources of the pre-merger Duke Energy Corporation or Cinergy. These synergies have reduced costs from eliminating overlapping functions, avoiding duplicative expenditures, consolidating operations and increasing purchasing power.

Customers immediately benefited from the merger via the merger savings sharing mechanism, approved by the Commission's November 29, 2005, Order in Case No. 2005-00228. Merger savings will continue to flow to customers through base rates. Therefore, Customers will receive additional benefits in future rate proceedings because the merger will enable us to keep Duke Energy Kentucky's costs lower, and will enable us to provide gas and electric utility service at reasonable prices.

The merger created a broader base of employees over a larger geographic area. This has better enabled Duke Energy's operating companies to provide mutual assistance to each other during severe weather conditions. Duke Energy Kentucky's customers will continue to enjoy safe, reliable and reasonably priced service as a result of the merger.

Q. DOES DUKE ENERGY KENTUCKY'S PROPOSED GAS RATE INCREASE RESULT FROM THE DUKE/CINERGY MERGER?

A. Absolutely not. Duke Energy Kentucky's gas distribution operating and maintenance expenses are virtually unchanged since the time of its last retail rate case which pre-dates the merger. This proposed rate increase was anticipated in connection with the conclusion of the Company's AMRP installation. This case will enable Duke Energy Kentucky to begin recovering in base rates its cost of investing in AMRP and, in part, to adjust rates for changes in customer usage patterns.

V. FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DISCUSS DUKE ENERGY KENTUCKY'S EXISTING PROGRAMS TO ACHIEVE IMPROVEMENTS IN EFFICIENCY AND PRODUCTIVITY AND THE PURPOSE OF EACH PROGRAM.

A. Duke Energy Kentucky is currently implementing the following programs designed to achieve improvements in efficiency and productivity:

- AMRP Program, and the Duke Energy/ Cinergy merger, which I discussed previously. The AMRP is also discussed in detail by Mr. Hebbeler;
- the Accelerated Riser Replacement Program, which is designed to improve the safety and reliability of Duke Energy Kentucky's gas distribution service by replacing field-assembled service head adapter style risers which exhibit factors associated with riser leaks. In order to manage this program in an efficient manner and optimize its resources, Duke Energy Kentucky is partnering with its sister utility, Duke Energy Ohio, who has instituted a similar program. This program is also discussed in more detail by Mr. Hebbeler;
- the Gas Transmission and Distribution Integrity Management Programs, which are designed to enhance the safety and reliability of Duke Energy Kentucky's gas distribution service by establishing a systematic plan to

perform periodic safety assessments and maintenance activities in response to new federal pipeline safety legislation, as discussed in more detail by Mr. Hebbeler;

- the Sewer line inspection program, which is a program designed to check potential high-risk gas main installations along sewer lines as a result of local sewer districts not maintaining accurate records of the location and depths of their systems. The Company inspects gas main installations that are likely to have experienced a breach based upon premises structure elevation and main line sewer location and depth in relation to the street; and
- Duke Energy Kentucky also offers Demand Side Management (DSM) programs which provide energy efficiency services to gas and electric customers. Currently there are four programs that provide benefits for gas customers. These programs include: (1) Residential Conservation and Energy Education (RCEE) (Low-Income Weatherization) program; (2) the Residential Home Energy House Call (HEHC) program; (3) Energy Efficient Web Site program; and (4) the Residential Comprehensive Energy Education program (NEED). These programs offer direct benefits to customers through energy efficiency education, energy use audits, and even home weatherization. Mr. Hebbeler discusses these programs in greater detail.

Q. PLEASE DESCRIBE FR 8(1) AND FR 8(2).

A. These filing requirements provide for the Company to seek proposed new rates through a written application addressing various matters, and to file a prescribed number of copies with the Commission. This was done at my direction.

Q. PLEASE DESCRIBE FR 10(1)(b)(2).

A. FR 10(1)(b)(2) certifies that Duke Energy Kentucky's annual reports are on file with the Commission, including the annual report for the most recent calendar year. These reports are typically filed by March 31st, annually, and we filed the current report as required by the Commission's rules.

Q. PLEASE DESCRIBE FR 10(1)(b)(3).

A. FR 10(1)(b)(3) is a certified copy of the Company's articles of incorporation, or a statement that the articles of incorporation were filed in a recent Commission proceeding. The current articles of incorporation and amendments for Duke Energy Kentucky are provided with our current filing.

Q. PLEASE DESCRIBE FR 10(1)(b)(4).

A. FR 10(1)(b)(4) applies to utilities that are limited partnerships; therefore, it does not apply to Duke Energy Kentucky which is a corporation.

Q. PLEASE DESCRIBE FR 10(1)(b)(5).

A. FR 10(1)(b)(5) is a certificate of good standing or authorization which we provide with our filing.

Q. PLEASE DESCRIBE FR 10(1)(b)(6).

A. FR 10(1)(b)(6) is a certificate of assumed name. Duke Energy Kentucky's actual legal name is "Duke Energy Kentucky, Inc." The Company has filed for the assumed name of "The Union Light, Heat and Power Company." The certificate of assumed name is provided with our filing.

Q. PLEASE DESCRIBE FR 10(1)(b)(9).

A. FR 10(1)(b)(9) is a statement verifying that customer notice has been provided in accordance with the Commission's rules.

Q. PLEASE DESCRIBE FR 10(4).

A. FR 10(4) is a description of how the customer notice of the rate proposal was provided pursuant to the Commission's rules.

Q. PLEASE DESCRIBE FR 10(9)(a).

A. FR 10(9)(a) requires testimony from me, as the Company's chief officer in charge of Kentucky operations, about Duke Energy Kentucky's existing programs to achieve improvements in efficiency and productivity and the purpose of each program. I discussed these programs previously in my testimony.

Q. PLEASE DESCRIBE FR 10(9)(e).

A. FR 10(9)(e) is the management attestation of the reasonableness of the financial data for the forecasted test period. In preparing this document, I reviewed the testimony of Duke Energy Kentucky's witnesses, including Mr. Lee, regarding how the forecasted test period data was developed. I also discussed this matter with Mr. Lee. I can attest that the forecasted test period data submitted in this proceeding is reasonable, reliable, and made in good faith; that the assumptions have been identified and justified; that the assumptions and methodologies are the same used by management; and that productivity and efficiency gains are included in the forecast. I signed the statement of attestation to this effect, which is provided with the filing requirements submitted by the Company.

VI. <u>INTRODUCTION OF WITNESSES</u>

Q. PLEASE INTRODUCE THE OTHER DUKE ENERGY KENTUCKY WITNESSES IN THIS PROCEEDING, AND EXPLAIN THE SUBJECT MATTER OF THEIR TESTIMONY.

A. Gary J. Hebbeler, General Manager of Gas Engineering, will provide additional testimony regarding the operation of Duke Energy Kentucky's gas business, and he also supports the operation and maintenance budget used in the base period and as a basis for the forecasted test period. Mr. Hebbeler also provides a detailed status of Duke Energy Kentucky's AMRP. He also supports the capital expenditure budget used in the base period and as a basis for the forecasted test period.

Brenda R. Melendez, Manager, USFE&G Midwest Accounting, will discuss Duke Energy Kentucky's accounting processes and will sponsor certain information related to Duke Energy Kentucky's plant accounting.

John J. Spanos, of Gannett Fleming, Inc., will sponsor Duke Energy Kentucky's latest depreciation study.

Timothy A. Phillips, Lead Forecaster, will testify regarding forecasting methodologies and supports the Duke Energy Kentucky gas and electric sales used in the forecasted test period data.

Jay R. Alvaro, Vice President Total Rewards, will testify regarding Duke Energy Kentucky's employee base and the Company's employee incentives, compensation and benefit programs, including the wage and salary and loading rate assumptions used in the forecasted test period data.

Stephen G. De May, Senior Vice President, Treasurer and Chief Risk Officer, will discuss Duke Energy Kentucky's credit ratings, financial objectives, cash requirements, financial practices, and capital structure.

David L. Doss, General Manager Corporate Accounting, will provide testimony regarding service company cost assignments.

Stephen R. Lee, Director Financial Forecasting, will discuss Duke Energy Kentucky's budgeting process and sponsor the forecasted test period data.

Dr. Roger A. Morin, an independent consultant, will provide expert testimony on Duke Energy Kentucky's requested return on equity.

Donald L. Storck, Director Rates Services, will sponsor Duke Energy Kentucky's cost of service study.

James E. Ziolkowski, Rates Manager, will provide testimony regarding rate design and changes to Duke Energy Kentucky rate schedules and other gas tariff provisions.

Robert M. Parsons, Manager Rates, will sponsor information related to Duke Energy Kentucky's revenue requirements, various tax matters affecting this proceeding, and certain adjustments Duke Energy Kentucky is making to the forecasted test period data.

William Don Wathen Jr., Director Rates, will provide an overview and summary of this case, and provide further testimony regarding Duke Energy Kentucky's request for continued timely recovery of the costs of the AMRP.

VII. <u>CONCLUSION</u>

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

A. Yes.

VERIFICATION

State of Ohio)
)
County of Hamilton)

The undersigned, Julia S. Janson, being duly sworn, deposes and says that she is the President of Duke Energy Kentucky, Inc. and Duke Energy Ohio, Inc., that she has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of her information, knowledge and belief.

Julia S. Janson

Julia S. Janson, Affiant

Subscribed and sworn to before me by Julia S. Janson on this 16th day of June, 2009.

Patty A. Selm

NOTARY PUBLIC

My Commission Expires:

PATTY A. SELM
NOTARY PUBLIC, STATE OF OHIO
My Commission Expires 09-15-2009

280091

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN ADJUSTMENT	)	
OF GAS RATES OF	)	CASE NO. 2009-00202
DUKE ENERGY KENTUCKY, INC.	)	

DIRECT TESTIMONY OF

STEPHEN R. LEE

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

July 1, 2009

269048

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Stephen R. Lee. My business address is 139 East Fourth Street, Cincinnati, Ohio.

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

A. I am employed by Duke Energy Business Services LLC, an affiliate service company of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company), as Director, Financial Forecasting.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from Ball State University in 1977 with a Bachelor of Science in Accounting. In 1987, I earned a Masters in Business Administration from Indiana Wesleyan University.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. I became employed by Public Service Company of Indiana, Inc. (PSI) in 1977 as a staff accountant. I held various positions in a number of areas, including Fixed Assets, Treasury, Budgets General Accounting and Internal Audit up through the merger between PSI and The Cincinnati Gas & Electric Company (Cinergy Merger) and the formation of Cinergy Corp. (Cinergy). Following the Cinergy Merger, I held several project manager positions. In 1998, I became the Director of Accounting for Cinergy's Energy Merchant/Commercial Business Unit. In November of 2004, I was promoted to Director of Financial Planning and Analysis for Cinergy's Commercial Business Unit. Upon consummation of the merger between Cinergy and Duke Power Corporation (Duke Merger), I took on my current role as Director of Financial Forecasting for Duke Energy Corp.'s (Duke Energy) U.S. Franchised Electric and Gas Businesses, Duke Energy Ohio, Inc. (Duke Energy Ohio) and Duke Energy Kentucky.

Q. PLEASE DESCRIBE YOUR DUTIES AS DIRECTOR, FINANCIAL FORECASTING.

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

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

A. No, I have not.

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

A. I explain Duke Energy Kentucky's budgeting and forecasting process. 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 *pro forma* adjustments and the long-term financial forecast, which were prepared under my direction and control. I also sponsor Filing Requirements (FR) 10(8)(d), 10(8)(e), 10(9)(c), 10(9)(d), 10(9)(h), and Schedules I-1 through I-5, and a portion of Schedule K.

II. THE BUDGETING AND FORECASTING PROCESS

Q. PLEASE DESCRIBE THE PROCESS FOR PREPARING THE ANNUAL BUDGET.

A. Duke Energy uses a "bottom up" budgeting approach. The budget information is provided by over 400 "centers" or management teams that prepare detailed budgets for their individual areas of responsibility, consisting of expense items, certain types of revenues, and capital spending. The budgets prepared by these individual centers (also referred to as "budget centers") are reviewed and approved by Duke Energy management. The Duke Energy Board of Directors ultimately approves the Duke Energy consolidated annual budget. If any changes occur during the review and approval process, the changes are communicated to the appropriate center, and this center submits a revised budget through the same review and approval process.

Q. ARE ANNUAL BUDGETS AND LONG-TERM FORECASTS PREPARED FOR DUKE ENERGY KENTUCKY?

A. Yes. Each year, Duke Energy prepares a five-year forecast of operating revenues and expenses, which is the starting point for preparing the annual budget. Along with the annual operating budget, additional years are added to develop a five year forecast.

III. METHODOLOGY FOR ANNUAL BUDGET

A. INCOME STATEMENT

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

A. The first step in preparing the operating revenues is to obtain a forecast of the projected gas and electric sales. As described by Duke Energy Kentucky witness Mr. Timothy A. Phillips, Duke Energy's Customer Market Analytics Department prepares these load forecasts on a monthly basis for each customer class over a ten-year period. The forecasts are updated at least annually. The Customer Market Analytics Department also provides the number of customers for each customer class. The projected revenues for the annual budget and the five-year forecast for gas and electric sales were calculated by applying the tariff charges to these sales forecast numbers for gas customers and for residential electric customers. The projected revenues for non-residential electric customers were calculated by using average realizations.

Q. WAS ANY WEATHER NORMALIZATION UTILIZED FOR THESE FORECASTS?

A. Yes. This is the same methodology that management incorporates for preparing its budgets and forecasts and for presentations of financial projections to the Board of Directors, credit ratings agencies and the investment community.

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

A. We analyzed historical trends of other revenues and receive information from the business groups supporting the forecast in order to obtain the other revenues for the five-year period.

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 Duke Energy Business Services, LLC, and other affiliates, as discussed by Duke Energy Kentucky witness Mr. David L. Doss. The regulatory assets were amortized using the amortization schedules approved by the Kentucky Public Service Commission.

Q. HOW DID YOU OBTAIN THE DEPRECIATION EXPENSE FOR THE INCOME STATEMENT PORTION OF THE ANNUAL BUDGET?

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. Brenda Melendez 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. HOW DID YOU OBTAIN THE PROPERTY TAX EXPENSE FOR THE INCOME STATEMENT PORTION OF THE ANNUAL BUDGET?

A. Duke Energy Kentucky's Property tax expense is calculated in the budget by applying current property tax rates and a projected assessment ratio to projected plant in service balances for the year. The projected plant in service values are supplied to the tax department that, in turn, applies the projected assessment ratios and estimated property tax rates by class of property.

Q. HOW DID YOU OBTAIN THE "OTHER INCOME AND EXPENSE" FOR THE INCOME STATEMENT PORTION OF THE ANNUAL BUDGET?

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 Allowance for Funds Used During Construction (AFUDC) was obtained from the five-year gas and electric capital forecasts. AFUDC rates were developed based on historical and forecasted debt financing and returns on equity. Miscellaneous revenues and expenses such as gas jobbing revenues and expenses and rent on non-utility property, were obtained from the annual budget.

Q. HOW DID YOU OBTAIN THE INTEREST EXPENSE FOR THE INCOME STATEMENT PORTION OF THE ANNUAL BUDGET?

A. Duke Energy Kentucky witness Mr. Stephen G. De May provided the long-term debt balances and long and short-term interest rates for the annual budget and the five-year forecast. The amount of short-term debt balances and associated interest expense were calculated using our forecasting tools.

Q. HOW DID YOU OBTAIN THE INCOME TAX EXPENSE FOR THE INCOME STATEMENT PORTION OF THE ANNUAL BUDGET?

A. Mr. Parsons provided the appropriate state and federal income tax rates. He also supplied me with book/tax temporary difference amounts and the amortization of investment tax credit (ITC) used to reduce the income tax expense. The income tax expense calculation was performed for each month of the annual budget period by applying existing statutory income tax rates to applicable taxable income and adjusting the resulting applicable income taxes by deferred income taxes and the ITC amortization amounts.

B. BALANCE SHEET

Q. HOW DID YOU OBTAIN THE INITIAL BALANCES FOR THE BALANCE SHEET FOR THE ANNUAL BUDGET?

A. The actual November 2008 balances from the balance sheet were used.

Q. HOW DID YOU OBTAIN THE NET PLANT FOR THE BALANCE SHEET?

A. Ms. Melendez supplied the net book value for the existing gas, electric and common plant for the period ending November 2008.

Q. HOW DID YOU OBTAIN THE REGULATORY ASSET ADJUSTMENTS FOR THE BALANCE SHEET PORTION OF THE ANNUAL BUDGET?

A. The adjustments to the regulatory assets were obtained from schedules produced by the Company's Accounting Department, reflecting amortization rates previously approved by the Commission.

Q. HOW DID YOU DETERMINE DIVIDENDS OR EQUITY FUNDING REQUIREMENTS IN THE ANNUAL BUDGET?

A. Dividends or equity funding for Duke Energy Kentucky are determined to the extent they are required to maintain the appropriate capitalization ratios as outlined by Mr. De May.

Q. HOW DID YOU OBTAIN THE FINANCING ACTIVITIES FOR THE BALANCE SHEET PORTION OF THE ANNUAL BUDGET?

A. Mr. De May provided the projected changes in long-term debt. He also supplied me with the amount of meter lease payments and regulator lease payments. He supplied this information for the annual budget and the five-year forecast.

Q. HOW DID YOU OBTAIN THE ACCUMULATED DEFERRED INCOME TAXES FOR THE BALANCE SHEET PORTION OF THE ANNUAL BUDGET?

A. The accumulated deferred income tax balance was derived using the beginning accumulated deferred income tax balance, plus the deferred income tax expense.

C. CASH FLOW STATEMENT

Q. HOW DID YOU PREPARE THE CASH FLOW STATEMENT FOR THE ANNUAL BUDGET?

A. The cash flow statement was prepared simply by using the corresponding inputs from the income statement and the balance sheet.

IV. METHODOLOGY FOR FORECASTED TEST PERIOD DATA

Q. HOW DID YOU PREPARE THE FORECASTED TEST PERIOD DATA?

A. The forecasted test period consists of the twelve months ending January 31, 2011. I prepared the forecasted test period data using data from the 2009 detailed annual budget process, including the data supplied for the five-year forecast.

Q. WHAT ADJUSTMENTS DID YOU MAKE TO THE DETAILED 2009 ANNUAL BUDGET FOR EXPENSES TO DEVELOP THE FORECASTED TEST PERIOD DATA?

A. Adjustments through January 2011 were calculated utilizing an approach very similar to the annual budget. Support groups within the business reviewed and adjusted data in accordance with general budget guidelines. Escalations were applied to labor based on expected union and non-union increases. Non-labor escalations were applied based on standard escalation factors applied throughout the forecast period.

Q. HOW DID YOU DEVELOP OTHER FORECASTED FINANCIAL DATA FOR THE TWELVE MONTHS ENDED JANUARY 31, 2011, SUCH AS INTEREST EXPENSE AND INCOME TAXES?

A. The interest levels are a product of the debt rates, the long-term debt outstanding, any redemptions or issuances and the short-term financing needs as determined by the cash inflows and cash outflows for the test period. The financing results were reviewed by Mr. De May to determine whether any adjustments to Duke Energy Kentucky's financing plan were necessary. Income taxes were calculated using the forecasting model. The calculation was performed for each month of the forecasted period by applying existing statutory income tax rates to applicable taxable book income and adjusting the resulting applicable income taxes by the ITC amortization amounts. Deferred income taxes were also calculated based on current book and tax deprecation rates and other applicable factors used to calculate federal income taxes. The amount of deferred income taxes was obtained using a calculation reviewed and approved by Mr. Parsons. He also provided the amount of tax depreciation for this calculation.

V. REASONABLENESS OF FORECASTED TEST PERIOD DATA

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

A. Yes. The data for the twelve months of the forecasted test period is based on the same data as contained in the detailed annual 2009 budget. In my opinion, as

Director Financial Forecasting, these budgeting and forecasting processes are adequate, reasonable and reliable.

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

A. Yes.

VI. SCHEDULES SPONSORED BY WITNESS

Q. PLEASE DESCRIBE FR 10(8)(d).

A. FR 10(8)(d) is a requirement stating that 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 such 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 days of a scheduled hearing on the rate application. The Company will follow this requirement.

Q. PLEASE DESCRIBE FR 10(8)(e).

A. FR 10(9)(e) is a requirement stating that the Commission may require the utility to prepare an alternate forecast based on a reasonable number of changes in the variables, assumptions, and other factors used as the basis for the utility's forecast. The Company will prepare an alternative forecast at the request of the Commission.

Q. PLEASE DESCRIBE FR 10(9)(c).

A. FR 10(9)(c) is a summary of the assumptions used to prepare the forecasted test period data. The Company's assumptions and methodologies have also been described in my testimony and the testimony of the other witnesses.

Q. PLEASE DESCRIBE FR 10(9)(d).

A. FR 10(9)(d) is Duke Energy Kentucky's annual and monthly twelve-month budget preceding the filing date, and for the base period and forecasted period.

Q. PLEASE DESCRIBE FR 10(9)(h).

A. FR 10(9)(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 flows, and certain other required financial and statistical information. Mr. Hebbeler sponsors 10(9)(h)(8). Mr. De May is responsible for FR 10(9)(h)(11).

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

A. Schedule I-1 satisfies FR10(10)(i). Schedule I-1 contains comparative income statements for the Company. Schedules I-2.1 through I-5, contain comparative revenue and sales statistical information as required by the Commission's filing requirements.

VII. <u>INFORMATION PROVIDED TO OTHER WITNESSES</u>

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

A. Yes, I provided Ms. Melendez with the budget and forecast data presented on the schedules of Section B that she sponsors.

VIII. CONCLUSION

Q. WERE FR 10(9)(C), 10(9)(D), FR 10(9)H, AND SCHEDULES I-1 THROUGH I-5, AND K PREPARED BY YOU OR UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

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

A. Yes.

VERIFICATION

State of Ohio)
)
County of Hamilton)

The undersigned, Stephen R. Lee, being duly sworn, deposes and says that he is the Director, Financial Forecasting for Duke Energy Business Services, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Stephen R. Lee

Stephen R. Lee, Affiant

Subscribed and sworn to before me by Stephen R. Lee on this 19th day of June, 2009.

Anita M. Schafer

NOTARY PUBLIC

My Commission Expires:

NOTARY PUBLIC STATE OF OHIO

ANITA M. SCHAFER
Notary Public, State of Ohio
My Commission Expires
November 4, 2009

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN ADJUSTMENT	)	
OF GAS RATES OF	)	CASE NO. 2009-00202
DUKE ENERGY KENTUCKY, INC.	)	

DIRECT TESTIMONY OF

BRENDA R. MELENDEZ

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

July 1, 2009

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Brenda R. Melendez. My business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

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

A. I am employed by Duke Energy Business Services, LLC, an affiliate service company of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or Company) as Manager, United States Franchised Electric and Gas (USFE&G) Midwest Accounting.

Q. PLEASE SUMMARIZE YOUR EDUCATION.

A. I earned a Bachelor of Science degree with a major in accounting from Ball State University in 1992.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. In 1992, I began my career with PSI Energy, Inc. (nka Duke Energy Indiana) as a staff accountant in the Cost Accounting Department. I progressed through various positions in the accounting, tax, and financial operations departments to Senior Analyst. In 1999, I was promoted to supervisor and I was transferred to the General Accounting Department. In 2004, I participated on a project team to upgrade general ledger, consolidation and financial reporting systems. In 2005, I was promoted to manager and I was transferred to Fixed Assets and Cost Accounting. After the Duke Energy/Cinergy Corp. merger in 2006, I transferred to the USFE&G Midwest Accounting Department. In 2007, I participated on a project team to integrate Cinergy's legacy financial systems with Duke Energy's enterprise financial systems. After completion of that project in July 2008, I returned to the USFE&G Midwest Accounting Department.

Q. PLEASE DESCRIBE YOUR DUTIES AS MANAGER, USFE&G MIDWEST ACCOUNTING.

A. I am responsible for reporting the financial results and maintaining the books of account for two of Duke Energy's Midwest public utility operating companies, Duke Energy Ohio, Inc. (Duke Energy Ohio) and Duke Energy Kentucky, Inc. (Duke Energy Kentucky). I am also responsible for analyzing these financial results and our underlying accounting methods and policies.

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

A. No.

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

A. I am responsible for historical net plant in service and construction work in progress contained in rate base and other plant-related items that Duke Energy Kentucky witness Mr. Stephen R. Lee us es in his testimony. I sponsor the following Schedules: B-2, B-2.1, B-2.2, B-2.3, B-2.4, B-2.5, B-2.6, B-2.7, B-3, B-3.1, B-3.2, B-4, B-8, and the plant data on Schedule K. I also sponsor the following filing requirements (FR): 6(9), 10(1)(b)(2), 10(9)(i), 10(9)(k), 10(9)(l), 10(9)(m), 10(9)(n), 10(9)(o), 10(9)(p), 10(9)(q) and 10(9)(r).

II. OVERVIEW OF DUKE ENERGY KENTUCKY'S ACCOUNTING RECORDS

Q. ARE YOU FAMILIAR WITH THE ACCOUNTING PROCEDURES AND

BOOKS OF ACCOUNT OF DUKE ENERGY KENTUCKY?

A. Yes. The books of account for Duke Energy Kentucky follow the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC).

Q. ARE THE BOOKS OF ACCOUNT FOR DUKE ENERGY KENTUCKY PREPARED AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes.

Q. ARE THE CAPITAL AND OPERATING EXPENDITURES REPRESENTED ON DUKE ENERGY KENTUCKY'S BOOKS OF ACCOUNT ACCURATE AND REASONABLE?

A. Yes. Duke Energy Kentucky has put in place various budgeting, planning, and review procedures to establish and monitor the capital and operating budgets as well as actual expenditures. The system of internal accounting controls provides reasonable assurance that all transactions are executed in accordance with management's authorization and are recorded properly.

The system of internal accounting controls is annually reviewed, tested, and documented by Duke Energy Kentucky to provide reasonable assurance that amounts recorded on the books and records of the Company are accurate and proper. In addition, independent certified public accountants perform an annual audit to provide assurance that internal accounting controls are operating effectively and that Duke Energy Kentucky's financial statements are materially accurate.

III. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE THE INFORMATION CONTAINED IN THE SCHEDULES OF SECTION B THAT YOU SPONSOR.

A. The schedules of Section B that I sponsor develop the Jurisdictional Net Plant In Service. The schedules are based on the Company's budget records as of the end of the base period on September 30, 2009, and the end of the forecasted period on January 31, 2011. Mr. Lee supplied the budget and forecast data presented on these schedules.

Q. PLEASE DESCRIBE SCHEDULE B-2.

A. Schedule B-2 shows the investment in gas plant in service including allocated common plant by major property grouping for the base period and the 13-month average as of the plant valuation date of January 31, 2011. The amount shown in the column labeled "Adjusted Jurisdiction," on page 1 of 2, and "13 Month Average Adjusted Jurisdiction," on page 2 of 2, represents plant in service that is used and useful in providing gas service to our Duke Energy Kentucky jurisdictional customers.

Q. PLEASE DESCRIBE SCHEDULE B-2.1.

A. Schedule B-2.1 consists of a further breakdown of Schedule B-2 by FERC and Company Account for each major property grouping for the base period and the forecasted period. The plant in service investment shown in the column labeled "Adjusted Jurisdiction," on pages 1 through 4, and "13 Month Average Adjusted Jurisdiction," on pages 5 through 8, represents gas plant in service including allocated common plant that is used and useful in providing gas service to our Duke Energy Kentucky jurisdictional customers.

Q. PLEASE DESCRIBE SCHEDULE B-2.2.

A. Schedule B-2.2 shows proposed adjustments to plant in service for the base period and the forecasted period. The Company eliminated from plant in service $12,357,099 for Facilities Devoted to Other Than Kentucky Customers for the 13-month average as of January 31, 2011. These facilities are the Erlanger propane cavern and processing facilities, various gas feederlines and odorization stations that are either partially or wholly used for the benefit of Duke Energy Ohio. Duke Energy Kentucky owns the cavern and bills Duke Energy Ohio for the portion used by Duke Energy Ohio.

Q. PLEASE DESCRIBE SCHEDULE B-2.3.

A. Schedule B-2.3 shows gross additions, retirements and transfers by FERC and Company Account for each major property grouping for the base period and the forecasted period.

Q. PLEASE DESCRIBE SCHEDULE B-2.4.

A. Schedule B-2.4 is entitled "Property Merged or Acquired" for the base period and the forecasted period. Since Duke Energy Kentucky projects that no property will be merged or acquired for the base period and the forecasted period, no items appear on this schedule.

Q. PLEASE DESCRIBE SCHEDULE B-2.5.

A. Schedule B-2.5 is entitled "Leased Property" and provides data for the base period and the forecasted period. Duke Energy Kentucky (fka, The Union Light

Heat & Power Co.) began leasing new gas meters in 1999 and began leasing new gas regulators in 2002. Duke Energy Kentucky also entered into a lease for a building in Erlanger, Kentucky, in 2005 to house its gas and electric construction and maintenance operations. Schedule B-2.5 contains the cost of gas meters and regulators and the cost associated with the building lease prior to allocation.

Q. PLEASE DESCRIBE SCHEDULE B-2.6.

A. Schedule B-2.6 shows the property held for future use included in rate base for the base period and the forecasted period. Since the Company has not included any property held for future use in rate base, no further information is provided.

Q. PLEASE DESCRIBE SCHEDULE B-2.7.

A. Schedule B-2.7 contains data on property excluded from rate base for the base period and the forecasted period. Since no property was excluded for other than jurisdictional purposes, no further information is provided.

Q. PLEASE DESCRIBE SCHEDULE B-3.

A. Schedule B-3 shows the total plant investment and the Reserve for Accumulated Depreciation and Amortization by FERC and Company Account grouping for the base period and the forecasted period. The amounts presented for the forecasted period on pages 5 through 8 are 13-month averages. The adjusted jurisdictional reserve in the last column is applicable to the jurisdictional plant shown on Schedule B-2, "Adjusted Jurisdiction," and "13 Month Average Adjusted Jurisdiction."

Q. PLEASE DESCRIBE SCHEDULE B-3.1.

A. Schedule B-3.1 shows adjustments to Accumulated Depreciation and

Amortization for the base period and the forecasted period. I eliminated from Accumulated Depreciation and Amortization $7,896,329 associated with the Facilities Devoted to Other Than Kentucky Customers eliminated on Schedule B-2.2 for the forecasted period.

Q. PLEASE DESCRIBE SCHEDULE B-3.2.

A. Schedule B-3.2 lists the 13-month average jurisdictional plant investment and reserve balance as of January 31, 2011 for each FERC and Company Account within each major property grouping. It also shows the proposed depreciation and amortization accrual rate, calculated annual depreciation and amortization expense, percentage of net salvage, average service life and curve form, as applicable, for each account. The calculated annual depreciation and amortization was determined by multiplying the 13-month average adjusted jurisdictional plant investment as of January 31, 2011, by the proposed depreciation and amortization accrual rates.

With this filing, the Company filed with the Kentucky Public Service Commission (Commission) proposed depreciation and amortization accrual rates prepared as of December 31, 2008, and sponsored by Duke Energy Kentucky witness Mr. John J. Spanos of Gannett Fleming Valuation and Rate Consultants, Inc., who prepared the depreciation study. The account numbers referred to in the depreciation study were those in effect in 2008 for Duke Energy Kentucky. The Company requests that the Commission approve the new depreciation and amortization accrual rates included in this filing and that the depreciation and amortization accrual rates be effective with the gas rates established in this case.

Q. PLEASE DESCRIBE SCHEDULE B-4.

A. Schedule B-4 is a list of Construction Work in Progress (CWIP) by major property grouping for the base period and the forecasted period. CWIP is broken down by amounts subject to Allowance for Funds Used During Construction (AFUDC) and amounts not subject to AFUDC. CWIP associated with Facilities Devoted to Other than Kentucky Customers has been eliminated from the CWIP appearing on this schedule.

Q. ARE YOU FAMILIAR WITH THE METHODOLOGY THE COMPANY USES TO CALCULATE AFUDC RATES?

A. Yes.

Q. PLEASE EXPLAIN HOW THE COMPANY CALCULATES AFUDC RATES.

A. The Company calculates AFUDC rates in accordance with the Federal Power Commission (now FERC) Order No. 561 on a monthly basis. This Order requires the Company to consider three major components in the calculation of the AFUDC rates. The three components are the cost of short-term debt, the cost of long-term debt and the cost of common equity, in accordance with the formula prescribed in Order No. 561.

Q. PLEASE DESCRIBE SCHEDULE B-8.

A. Schedule B-8 contains comparative balance sheet information for the most recent five calendar years, the base period and the forecasted period.

Q. PLEASE DESCRIBE SCHEDULE K.

A. I sponsor the plant data and composite depreciation rates submitted on page 1 of 5 of Schedule K. This information includes Plant in Service by major property grouping and Reserve for Accumulated Depreciation and Amortization by utility service for the 13-month average as of September 30, 2009, for the base period and for December 31 for each of the last ten years. Plant held for future use and CWIP have also been provided for the same periods.

Q. PLEASE DESCRIBE FR 6(9).

A. FR 6(9) is a detailed income statement and balance sheet for the period ending March 31, 2009.

Q. PLEASE DESCRIBE FR 10(1)(b)(2).

A. FR 10(1)(b)(2) is a statement that Duke Energy Kentucky certifies that its annual reports are on file with the Commission in accordance with 807 KAR 5:006, Section (3)(1).

Q. PLEASE DESCRIBE FR 10(9)(i).

A. FR 10(9)(i) is a copy of the most recent FERC audit report for Duke Energy Kentucky, reporting on the results of the Company's last FERC audit.

Q. PLEASE DESCRIBE FR 10(9)(k).

A. FR 10(9)(k) provides the most recent FERC Form 1 and Form 2 reports for Duke Energy Kentucky.

Q. PLEASE DESCRIBE FR 10(9)(l).

A. FR 10(9)(l) consists of the most recent annual reports to shareholders for the five years prior to the application. Duke Energy Kentucky does not provide a formal annual report because Duke Energy Ohio owns 100% of Duke Energy Kentucky's shares of stock. I have provided the annual reports for Duke Energy Corp.

Q. PLEASE DESCRIBE FR 10(9)(m).

A. FR 10(9)(m) is a copy of the current chart of accounts for Duke Energy Kentucky.

Q. PLEASE DESCRIBE FR 10(9)(n).

A. FR 10(9)(n) requires the latest twelve months of the monthly management reports providing financial results of operations in comparison to the forecast. Duke Energy Kentucky does not prepare monthly management reports in comparison to the forecast. In the present case, Duke Energy Kentucky has provided the quarterly financial statements it filed with the Commission from June 2008 through March 2009.

Q. PLEASE DESCRIBE FR 10(9)(o).

A. FR 10(9)(o) consists of management's monthly budget variance reports for Duke Energy Kentucky and consolidated Ohio/Kentucky operations. Duke Energy issues reports primarily on a combined utility operating company, USFE&G level. However, the Company does prepare monthly summary reports for the individual utility operating companies. These summary reports provide narrative explanations for the significant variances.

Q. PLEASE DESCRIBE FR 10(9)(p).

A. On May 8, 2006, The Union Light, Heat and Power Company provided certification and notice of termination of duty to file reports under Sections 13 and 15(d) of the Securities and Exchange Act of 1934. Therefore, FR 10(9)(p) consists of the last two years' Form 10-Ks and Form 8-Ks filed with the U.S. Securities and Exchange Commission (SEC), as well as the Form 10-Qs filed during the past six quarters. Duke Energy Ohio, Inc. forms included Duke Energy Kentucky. Additionally, the Company is providing Duke Energy Kentucky's quarterly and annual financial statements for the same time periods although they were not filed with the SEC.

Q. PLEASE DESCRIBE FR 10(9)(q).

A. FR 10(9)(q) is the independent auditor's annual opinion report for Duke Energy Kentucky. The auditor did not note any material weaknesses in internal controls.

Q. PLEASE DESCRIBE FR 10(9)(r).

A. FR 10(9)(r) requires the Company to provide quarterly reports to stockholders for the most recent five quarters. Duke Energy Kentucky does not provide quarterly reports to Duke Energy Ohio and has not prepared quarterly reports to Duke Energy Ohio since 2002.

IV. CONCLUSION

Q. WERE SCHEDULES B-2, B-2.1, B-2.2, B-2.3, B-2.4, B-2.5, B-2.6, B-2.7, B-3, B-3.1, B-3.2, B-4, B-8, THE PLANT DATA ON SCHEDULE K AND FILING REQUIREMENTS 6(9), 10(1)(B)(2), 10(9)(i), 10(9)(k), 10(9)(l), 10(9)(m), 10(9)(n), 10(9)(o), 10(9)(p), 10(9)(q) AND 10(9)(r) PREPARED BY YOU OR UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

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

A. Yes.

VERIFICATION

State of Ohio)
)
County of Hamilton)

The undersigned, Brenda R. Melendez, being duly sworn, deposes and says that she is the Manager, USFE&G Midwest Accounting for Duke Energy Business Services, LLC, that she has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of her information, knowledge and belief.

Brenda R. Melendez

Brenda R. Melendez, Affiant

Subscribed and sworn to before me by Brenda R. Melendez on this 19th day of June, 2009.

Anita M. Schafer

NOTARY PUBLIC

My Commission Expires:

NOTARY PUBLIC STATE OF OHIO

ANITA M. SCHAFER
Notary Public, State of Ohio
My Commission Expires
November 4, 2009

COMMONWEALTH OF KENTUCKY

BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE ADJUSTMENT	)	
OF GAS RATES OF	)	
DUKE ENERGY KENTUCKY, INC.	)	CASE NO. 2009-00202

DIRECT TESTIMONY

OF

ROGER A. MORIN, PhD

ON BEHALF OF DUKE ENERGY KENTUCKY, INC

July 1, 2009

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, 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 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.

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 The Management Exchange Inc. and Exnet, Inc., where I continue to conduct frequent national executive-level education seminars throughout the United States and Canada. In the last thirty years, I have conducted numerous national seminars on "Utility Finance," "Utility Cost of Capital," "Alternative Regulatory Frameworks," and on "Utility Capital

Allocation," which I have developed on behalf of The Management Exchange Inc. and Exnet (now SNL Energy) in conjunction with Public Utilities Reports, Inc.

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 Regulatory Finance, a voluminous treatise on the application of finance to regulated utilities. A revised and expanded edition of this book entitled The New Regulatory Finance was published in August 2006. I have engaged in extensive consulting activities on behalf of numerous corporations, legal firms, and regulatory bodies in matters of financial management and corporate litigation. Attachment RAM-1 describes my professional credentials in more detail.

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

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

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

Details of my participation in regulatory proceedings are 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 the common equity capital (ROE) invested in Duke Energy Kentucky Inc.'s (Duke Energy Kentucky or the Company) natural gas delivery 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 the customer, (2) allow the Company to attract capital on reasonable terms, (3) maintain the Company's financial integrity, and (4) be comparable to returns offered on comparable risk investments. I will testify in this proceeding as to that opinion.

This testimony and accompanying schedules were prepared by me or under my direct supervision and control. The source documents for my testimony are Company records, public documents, commercial data sources, and my personal knowledge and experience.

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

A. I have attached to my testimony Attachment RAM-1 through Attachment RAM-8 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.

Attachment RAM-1	Resume of Roger A. Morin
Attachment RAM-2	Utility Beta Estimates
Attachment RAM-3	Combination Gas & Electric Utilities Beta Estimates
Attachment RAM-4	S&P Utility Common Stocks Over Long-Term Utility Bonds: Long-Term Risk Premium
Attachment RAM-5	Natural Gas Utilities - DCF Analysis: Value Line Growth Projections
Attachment RAM-6	Natural Gas Utilities - DCF Analysis: Analysts' Growth Forecasts
Attachment RAM-7	Combination Gas & Electric Utilities - DCF Analysis: Value Line Growth Projections
Attachment RAM-8	Combination Gas & Electric Utilities - DCF Analysis: Analysts' Growth Forecasts
Attachment RAM-9	Natural Gas Common Equity Ratios
Appendix A	CAPM and Empirical CAPM
Appendix B	Flotation Cost Allowance

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATION.

A. I have examined Duke Energy Kentucky's risks, and concluded that Duke Energy Kentucky's risk environment is comparable to the industry average. It is my opinion that a just and reasonable ROE invested in Duke Energy Kentucky's natural gas delivery operations is 11.0%, assuming that the Company's proposed capital structure is adopted.

My recommendation derives from studies that I performed using the Capital Asset Pricing Model (CAPM), Risk Premium, and Discounted Cash Flow (DCF) methodologies. I performed two CAPM analyses: a "traditional" CAPM and a methodology using an empirical approximation of the CAPM (ECAPM). I performed a historical risk premium analysis on the utility industry. I also performed DCF analyses on two surrogates for the Company's natural gas delivery business. They are: a group of investment-grade natural gas distribution utilities and a group of investment-grade dividend-paying combination gas and electric utilities with a majority of their revenues from regulated utility operations.

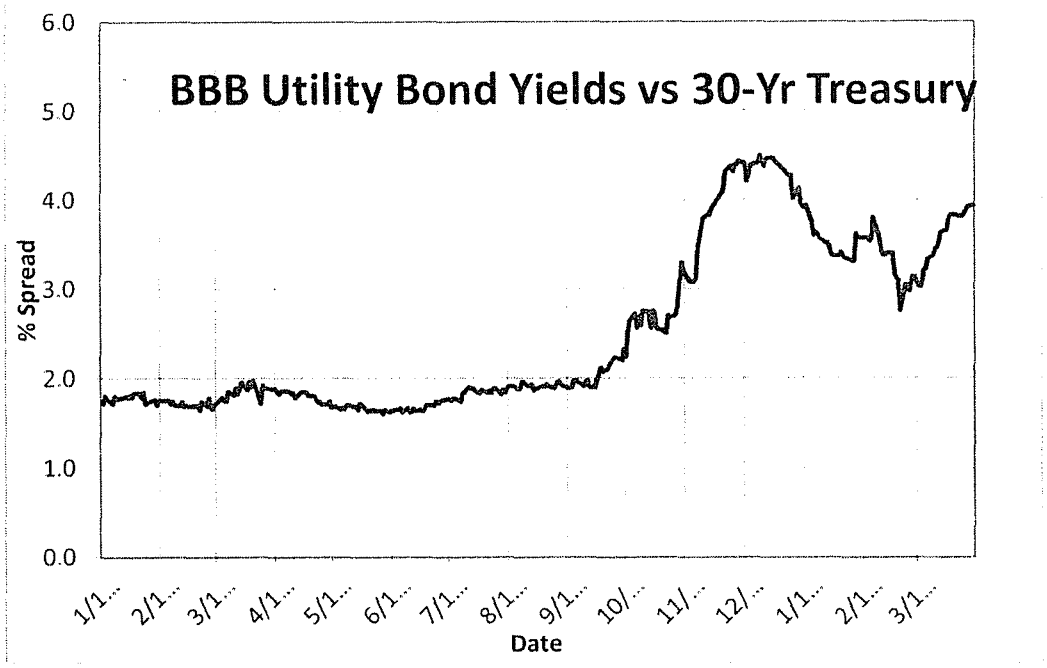
My recommended rate of return reflects the application of my professional judgment to the indicated returns from my CAPM, Risk Premium, CAPM, and DCF analyses, to the Company's current risk environment, which I estimate to be comparable on balance to the industry average, and to unprecedented capital market conditions of turmoil and uncertainty, as I discuss later in my testimony. My recommended ROE also assumes the approval of the Company's rate year capital structure consisting of 50% common equity capital.

Q. PLEASE DESCRIBE FOR US THE CURRENT STATE OF THE CAPITAL MARKETS.

A. Capital markets have been, and continue to be, in a state of turmoil. In the past nine months, the financial markets, both in the U.S. and abroad, have become extremely volatile, unpredictable, and have displayed unusual behavior. To illustrate, daily percentage changes in the Dow Jones Industrial Index have experienced unprecedented swings. The Chicago Board of Options Exchange (CBOE) Volatility Index (VIX), which measures the volatility of the S&P 500 Index, has increased to record highs. The turmoil in the capital markets is also reflected by highly unusual events, for example, the $700 billion government bailout of troubled financial institutions, the bankruptcy of Lehman Brothers, the collapse of Bear Stearns, the acquisition of Merrill Lynch by Bank of America, and the conversion of other major investment banks such as Morgan Stanley and Goldman Sachs to bank holdings companies, leaving no major investment banks.

Borrowers are now forced to compete in a market with dramatically less capital to invest. As a result, the cost of money for corporations has increased, and new debt issues are limited to the highest rated issuers. Common stock issues are scarce. The commercial paper market functions only due to decisive U.S. Treasury intervention. The debt markets have witnessed record high yield spreads (i.e., the incremental yield over Treasury rates needed to issue debt) and a more severe differentiation between the spreads charged to companies with different credit ratings. These market conditions have led to an increased value for higher credit ratings and for conservative capital structures.

To illustrate, the chart below depicts the rising and record high bond yield spreads in recent months for utilities rated BBB, the approximate average bond rating of the electric utility industry. Whereas throughout most of early 2008 utilities were borrowing money at some 150-200 basis points over Treasuries, the current secondary market spread (not including a significant new issuance premium) is 350-400 basis points, an increase of 150-200 basis points, which is approximately the same upward increase as has been observed in reliable DCF estimates of the cost of equity. In a nutshell, there is a fundamental structural upward shift in risk aversion as capital markets are re-pricing risk, and capital has become, and will continue to be, more expensive for all market participants. Moreover, the combination of Federal Reserve's loose monetary policy and the trillions of projected budget deficits creates a highly inflationary environment that is likely to increase the cost of capital well above historical levels for years to come.



Q. PLEASE BRIEFLY DESCRIBE THE RECENT BEHAVIOR OF INTEREST RATES.

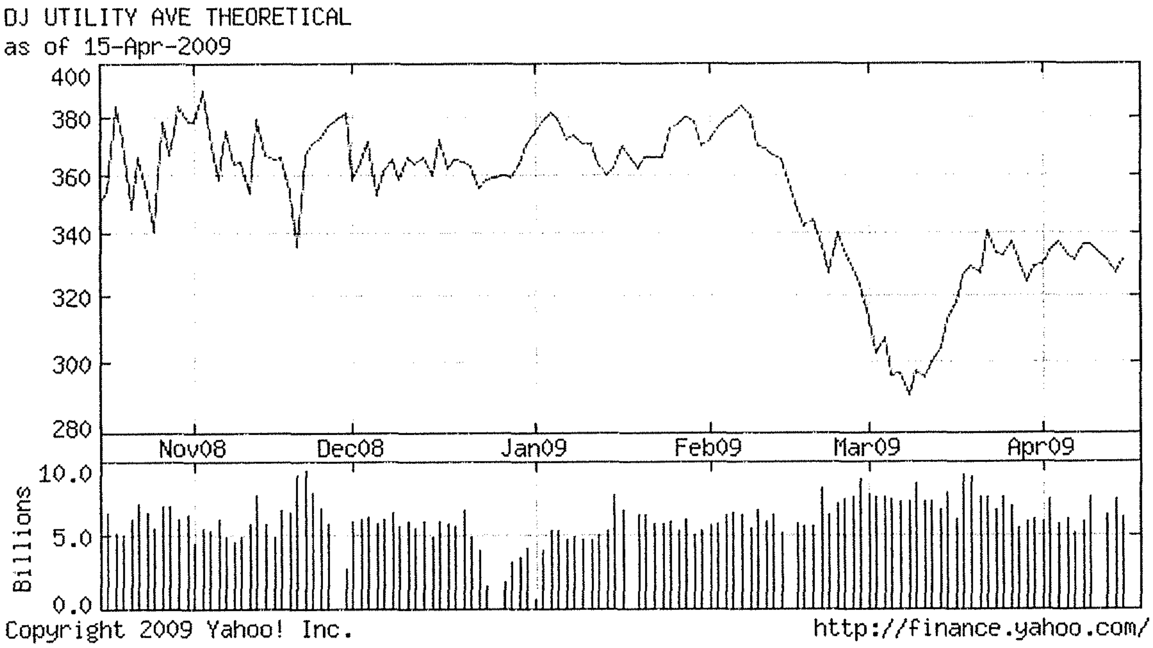
A. Draconian changes have occurred in capital market conditions in the last nine months. The current level of U.S. Treasury 30-year long-term bond yield is approximately 4.0%, versus 4.5% - 5.0% over the past several years. The decrease in interest rates produces very low CAPM and Risk Premium estimates that are based on this risk-free rate and do not capture the recent escalation in capital costs for the private sector. Capital costs for non-government entities have escalated to unprecedented levels relative to government securities since the financial crisis began in 2008.

Q. DR. MORIN, HAS THE MARKET RISK PREMIUM IN THE CAPM ANALYSIS CHANGED RECENTLY?

A. While the historical market risk premium (MRP) has not changed significantly, it is clear that the prospective MRP has increased markedly, given the disastrous performance of the equity markets and the ongoing re-pricing of risk by investors. It should be noted that the historical MRP that is often used in the CAPM analysis is measured over a long term and likely does not capture the re-pricing of risk that is currently occurring in the financial marketplace.

Q. DR. MORIN, PLEASE DESCRIBE WHAT HAS HAPPENED TO DCF-BASED COST OF EQUITY ESTIMATES SINCE THE FINANCIAL CRISIS COMMENCED.

A. Set forth below is a graph that replicates the movements of the Dow Jones Utility Average over the past nine months. The devastating downward impact of the financial crisis on utility stock prices is clear from the graph, with the utility index falling from the 370 level to the 330 level over the past six months. Lower stock prices imply higher dividend yields, which in turn imply higher DCF estimates.



Q. WHAT IS THE IMPACT OF THE ONGOING FINANCIAL CRISIS ON UTILITIES' COST OF CAPITAL AND ON DUKE ENERGY KENTUCKY PARTICULARLY?

A. In a nutshell, the cost of capital has increased markedly. During the past nine months, capital markets in the U.S. have been more volatile than at any time since the 1930s. Investors have witnessed unprecedented large swings in the stock market and unprecedented corporate interest rate spreads in the debt markets. Many large financial institutions were unable to survive as independent institutions and others have required multi-billion dollar capital infusions, principally from the Federal Government.

As shown above, the spreads between the yields on utility debt and U.S.

Treasury securities have increased markedly. Since the commencement of the financial crisis, single-A yield spreads and BBB yield spreads for utility companies have increased to a level which is some three times higher than the spreads that existed little more than a year ago. In short, increased risk aversion and market illiquidity have resulted in significantly higher borrowing costs for corporations, including Duke Energy Kentucky. In the current environment, investors' return expectations and requirements for providing capital to the utility industry remain high relative to the longer-term traditional view of the utility industry.

Q. WOULD IT BE IN THE BEST INTERESTS OF CUSTOMERS FOR THE COMMISSION TO ADOPT YOUR RECOMMENDED 11.0% ROE FOR DUKE ENERGY KENTUCKY?

A. Yes. My analysis shows that a ROE of 11.0% is required to fairly compensate investors, and to strengthen the Company's credit position. Adopting a lower ROE would increase costs for Duke Energy Kentucky's ratepayers.

Q. PLEASE EXPLAIN HOW THE COMMISSION'S ADOPTION OF A RETURN ON EQUITY LESS THAN THE RETURN REQUIRED BY INVESTORS CAN INCREASE BOTH THE FUTURE COST OF EQUITY AND DEBT FINANCING OF DUKE ENERGY KENTUCKY

A. If a utility is authorized a ROE below the level required by equity investors, the utility will find it difficult to access the equity market through common stock issuance at its current market price. Investors will not provide equity capital at the current market price if the expected return on equity capital 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 that investors believe is appropriate for the risk they bear, the result is a decrease in the utility's market price per share of common stock. 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, because 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 have to rely more on debt financing to meet its capital needs.

As the 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 even greater uncertainty about future dividends and earnings from the firm. As a result, the firm's equity becomes a riskier investment. The risk of default on the 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 the 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 11.0% is required.

It is imperative the Company have access to capital funds at reasonable terms and conditions. The Company must secure outside funds from capital markets to finance new infrastructure, irrespective of capital market conditions, interest rate conditions and the quality consciousness of market participants. Because the Company will need to rely on capital markets, rate relief requirements and supportive regulatory treatment, including approval of my recommended cost of equity, are essential requirements.

Q. DR. MORIN, PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

A. The remainder of my testimony is divided into three (3) sections:

- Regulatory Framework and Rate of Return;
- Cost of Equity Estimates; and
- Summary and Cost of Equity 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 CAPM, Risk Premium, and DCF tests. The third section summarizes the results from the various approaches used in determining a fair return.

II. REGULATORY FRAMEWORK AND RATE OF RETURN

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 the Company's cost of equity, one relating to the supply side of capital markets, the other to the demand side. According to the first principle, a rational investor is maximizing the performance of his portfolio only if he expects the returns earned on investments of comparable risk to be the same. If not, the rational investor 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 the capital funds it needs to meet its service demands and to maintain financial integrity 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 at least equals the company's cost of capital. This concept suggests that a regulatory commission should set rates at a level sufficient to create equality between the return on physical asset investments and the company's cost of capital.

Q. HOW DOES DUKE ENERGY KENTUCKY'S COST OF CAPITAL RELATE TO THAT OF ITS PARENT COMPANY, DUKE ENERGY CORPORATION (DUKE ENERGY)?

A. I am treating Duke Energy Kentucky's natural gas delivery operations as a separate stand-alone entity, distinct from its holding company, Duke Energy, because it is the cost of capital for Duke Energy Kentucky's natural gas utility business that we are attempting to measure and not the cost of capital for Duke Energy's consolidated activities. Financial theory establishes that the true cost of capital depends on the use to which the capital is put, in this case Duke Energy Kentucky's natural gas delivery operations in the State of Kentucky. The specific source of funding an investment and the cost of funds to the investor are irrelevant considerations.

For example, if an individual investor borrows money at the bank at an after-tax cost of 8% and invests the funds in a speculative oil extraction venture, the required return on the investment is not the 8% cost but, rather, the return foregone in speculative projects of similar risk, say 20%. Similarly, the required return on Duke Energy Kentucky is the return foregone in comparable risk energy delivery operations, and is unrelated to the parent's cost of capital. The cost of capital is governed by the risk to which the capital is exposed and not by the source of funds. The identity of the shareholders has no bearing on the cost of equity, be it either individual investors or a parent holding company.

Just as individual investors require different returns from different assets in managing their personal affairs, corporations behave in the same manner. A parent company normally invests money in many operating companies of varying sizes and varying risks. These operating subsidiaries pay different rates for the use of investor capital, such as for long-term debt capital, because investors recognize the differences in capital structure, risk, and prospects between subsidiaries. Thus, the cost of investing funds in an operating utility entity such as Duke Energy Kentucky is the return foregone on investments of similar risk and is unrelated to the investor's identity.

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

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 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 the 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, that is, investors' required rate of return, is more difficult to estimate. It is the purpose of the next section of my testimony to estimate Duke Energy Kentucky's cost of common equity capital.

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

A. The legal requirement is that the allowed 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 Risk Premium, CAPM, or DCF methods. These market value tests define fair return as the return that investors anticipate when they purchase equity shares of comparable risk in the financial marketplace. This return 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.

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. <u>Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia</u>, 262 U.S. 679 (1923).

2. Federal Power Commission v. Hope Natural Gas Company, 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." (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." (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. vs. Barasch, 488 U.S. 299 (1989). In the Permian 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..."

Therefore, the "end result" of the Commission's decision should be to allow Duke Energy Kentucky the opportunity to earn a return on equity that is: (1) commensurate with returns on investments in other firms having corresponding risks, (2) sufficient to assure confidence in the Company's financial integrity, and (3) sufficient to maintain the Company'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 (*i.e.*, 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.

While utilities like Duke Energy Kentucky enjoy varying degrees of monopoly in the sale of public utility services, they must compete with everyone else in the free, open market for the input factors of production, whether they be labor, materials, machines, or capital. 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 company's revenue requirement. This item 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, for example, the interest on debt capital, or the expected market return on common and/or preferred equity.

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 also are exposing their funds to risk and forgoing returns from investing their money in alternative comparable-risk investments. The compensation that 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. These differences in risk are translated by the capital markets into price differences in much the same way that differences in the characteristics of commodities are reflected in different prices.

The important point is that the prices of debt capital and equity capital are set by supply and demand, and both are influenced by the relationship between the risk and return expected for the respective securities and the risks expected from the overall menu of available securities.

Q. HOW DOES THE COMPANY OBTAIN ITS CAPITAL AND HOW IS ITS OVERALL COST OF CAPITAL DETERMINED?

A. The funds employed by the Company are obtained in two general forms, debt capital and equity capital. The latter consists of common equity capital. The cost of debt funds and preferred stock funds can be ascertained easily from an examination of the contractual terms for the interest payments and preferred dividends. 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. Moreover, as equity investors share in the ownership of all residual profits/losses of a company, they also expect to benefit/lose from the capital fluctuations inherent in undistributed earnings. Once a cost of common equity estimate has been developed, it can then easily be combined with the embedded cost of debt and preferred stock, based on the utility's capital structure, in order to arrive at the overall cost of capital.

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. Investors set return requirements according to their perception of the risks inherent in the investment, recognizing the opportunity cost of forgone investments, and the returns available from other investments of comparable risk.

III. <u>COST OF EQUITY ESTIMATES</u>

Q. DR. MORIN, HOW DID YOU ESTIMATE THE FAIR ROE FOR DUKE ENERGY KENTUCKY?

A. I employed three methodologies: (1) the CAPM, (2) the Risk Premium, and (3) the DCF. All three items are market-based methodologies and are 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 individual 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 dangerous to rely on 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 methodologies available to measure the cost of equity: DCF, Risk Premium, and CAPM. All three of these methodologies are accepted and used by the financial community and firmly supported in the financial literature. The weight accorded to any one methodology may very well vary depending on unusual circumstances in capital market conditions.

When measuring the cost of common equity, which essentially deals with the measurement of investor expectations, no one single methodology provides a foolproof panacea. Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory and apply the methodology. The failure of the traditional infinite growth DCF model to account for changes in relative market valuation, and the practical difficulties of specifying the expected growth component, are vivid examples of the potential shortcomings of the DCF model. It follows that more than one methodology should be employed in arriving at a judgment on the cost of equity and that all of these methodologies should be applied to multiple groups of comparable risk companies.

There is no single model that conclusively determines or estimates the expected return for an individual firm. Each methodology 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.

Q. ARE THERE ANY PRACTICAL DIFFICULTIES IN APPLYING COST OF CAPITAL METHODS IN THE CURRENT ENVIRONMENT OF CHANGES IN CAPITAL MARKETS AND IN THE UTILITY INDUSTRY?

A. Yes, there are. All the traditional cost of equity estimation methods are difficult to implement when you are dealing with the unprecedented conditions of instability and volatility in the capital markets and the fast-changing circumstances of the utility industry. This is not only because stock prices are extremely volatile at this time, but also utility company historical data have become less meaningful for an industry experiencing unprecedented volatility. Past earnings and dividend trends may simply not be indicative of the future. For example, historical growth rates of earnings and dividends have been depressed by eroding margins due to a variety of factors including structural transformation, restructuring, and the transition to a more competitive environment. Moreover, historical growth rates may not be representative of future trends for several utilities involved in mergers and acquisitions, as these companies going forward are not the same companies for which historical data are available.

Q. DR. MORIN, PLEASE PROVIDE AN OVERVIEW OF YOUR RISK

PREMIUM ANALYSES.

A. In order to quantify the risk premium for Duke Energy Kentucky, I performed three risk premium studies on proxies for the Company. The first two studies deal with aggregate stock market risk premium evidence using two versions of the CAPM methodology and the third study deals directly with the utility industry.

A. 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. 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 securities market as a whole by R_M, the CAPM is:

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

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 $\beta(R_M - R_F)$. To derive the CAPM risk premium estimate, three quantities are required: the risk-free rate (R_F), beta (β), and the market risk premium, ($R_M - R_F$). For the risk-free rate, I used 4.0% based on the current level of long-term Treasury interest rates. For beta, I used 0.72 and for the MRP, I used 6.5%. These inputs to the CAPM are explained below.

Q. HOW DID YOU DERIVE THE RISK FREE RATE OF 4.0%?

A. To implement the CAPM and Risk Premium methods, an estimate of the risk-free return is required as a benchmark. As a proxy for the risk-free rate, I have relied on the current level of 30-year Treasury bond yields.

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 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. Common stock is a very long-term investment because the cash flows to investors in the form of dividends last indefinitely. Thus, 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 investor'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. Thus 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.

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, 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 therefore will 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 actual yields on 30-year Treasury bonds will more closely incorporate within their yield the inflation expectations that influence the prices of common stocks than do short-term or intermediate-term U.S. Treasury notes.

Q. DR. MORIN, 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, as was seen recently in an attempt to combat the weak economy, 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. The level of U.S. Treasury 30-year long-term bonds prevailing in early May 2009 as reported in Value Line and the Federal Reserve Bank, is 4.0%. Accordingly, I shall use 4.0% as my estimate of the risk-free rate component of the CAPM. As I discuss later, while interest rates on government securities have decreased in the past year, the cost of borrowing for companies generally and utilities in particular have increased substantially.

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", or "systematic risk". The beta coefficient measures the 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. The beta coefficient 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.

As a wholly-owned subsidiary of Duke Energy, Duke Energy Kentucky is not publicly traded and, therefore, proxies must be used for Duke Energy Kentucky. As a first proxy for the Company's beta, I have examined the betas of a sample of widely-traded, investment-grade, and dividend-paying natural gas utilities covered by Value Line. This group is examined in more detail later in my testimony, in connection with the DCF estimates of the cost of common equity. As displayed on Attachment RAM-2, the average beta for the natural gas group is currently 0.70.

In view of the scarcity of publicly-traded pure-play natural gas distributors, I also examined the betas of a sample of widely-traded investment-grade combination gas and electric utilities with at least 50% of their revenues from regulated utility operations as a second proxy for the Company's natural gas business. This group is examined in more detail later in my testimony, in connection with the DCF estimates of the cost of common equity. As shown on Attachment RAM-3, the average beta of the distribution group is 0.74, which is very close to the beta of the gas group, confirming the risk comparability of the two groups. Based on these results, I shall use the average of the two estimates, 0.72, as a beta estimate for Duke Energy Kentucky's natural gas delivery operations. It is important to note that betas are estimated on five-year historical periods and, therefore, do not capture the dramatic increase in capital costs that have occurred since the ongoing financial crisis began October 2008.

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

A. For the MRP, I used 6.5%. This estimate was based on the results of both forward-looking and historical and studies of long-term risk premiums, mainly the latter. First, the Morningstar (formerly Ibbotson Associates) study, <u>Stocks, Bonds, Bills, and Inflation, 2009 Yearbook</u>, compiling historical returns from 1926 to 2008, shows that a broad market sample of common stocks outperformed long-term U. S. Treasury bonds by 5.6%. The historical MRP over the income component of long-term Treasury bonds rather than over the total return is 6.5%. Morningstar recommends the use of the latter as a more reliable estimate of the historical MRP, and I concur with this viewpoint. 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. This is because 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), as realized capital gains/losses are largely unanticipated by bond investors. The long-horizon (1926-2008) MRP (based on income returns, as required) is specifically calculated to be 6.5% rather than 5.6%.

Q. ON WHAT MATURITY BOND DOES THE MORNINGSTAR HISTORICAL RISK PREMIUM DATA RELY?

A. Because 30-year bonds were not always traded or even available throughout the entire 1926-2008 period covered in the Morningstar study of historical returns, the latter study relied on bond return data based on 20-year Treasury bonds. Since the normal yield curve was virtually flat for maturities longer than 20 years over most of the period covered in the Morningstar 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, because they are heavily dependent on short-term market movements. 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.

Q. DID YOU CHECK YOUR HISTORICAL MRP ESTIMATE WITH ANY OTHER SOURCE?

A. Yes, I did. As a check on my final MRP estimate of 6.5%, I examined a 2003 comprehensive article published in Financial Management (s ee 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). These authors provide estimates of the prospective expected returns for S&P 500 companies over the period 1983-1998. They 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. The prevailing risk-free rate for each year was then subtracted from the expected rate of return for the overall market to arrive at the MRP for that year. The average MRP estimate for the overall period is 7.2%, which is reasonably close to the historical of 6.5%, and almost identical to the historical estimate of 7.1% if the disastrous, and unexpected to recur, performance of the capital markets during 2008 is excluded from the historical average.

Q. DID YOU PERFORM ANY OTHER PROSPECTIVE ANALYSIS OF THE MRP?

A. No, I did not. In contrast to my past testimonies where I developed my own estimate of the prospective MRP by applying the DCF model to a broad stock market index, this same technique applied to current stock market data produces MRP estimates above the 9%-10% range on account of the very low level of government interest rates and the current turmoil in equity markets. Given the unsettled conditions in the equity market and in the interest of conservatism I shall therefore retain the historical MRP estimate of 6.5%. I view this estimate as extremely conservative in the current environment of chaos in capital markets.

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

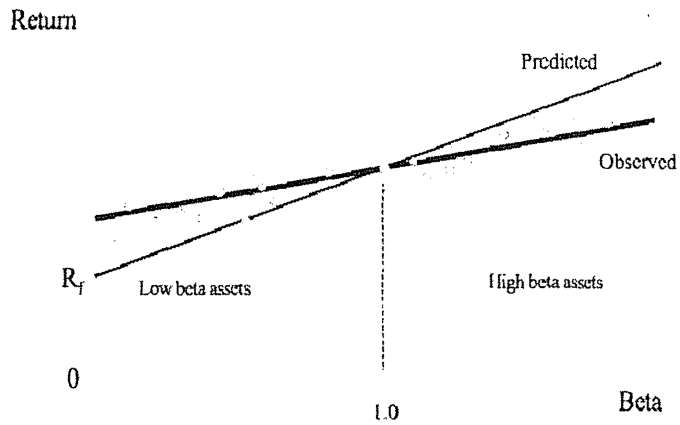
A. Inserting those input values in the CAPM equation, namely a risk-free rate of 4.0%, a beta of 0.72, and a MRP of 6.5%, the CAPM estimate of the cost of common equity for Duke Energy Kentucky is: 4.0% + 0.72 x 6.5% = 8.7%. This estimate becomes 9.0% with flotation costs, discussed later in my testimony.

Q. WHAT IS YOUR RISK PREMIUM ESTIMATE USING THE EMPIRICAL VERSION OF THE CAPM?

A. With respect to the empirical validity of the plain vanilla CAPM, 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 13 of my 1994 book, Regulatory Finance, and Chapter 6 of my latest book, The New Regulatory Finance, both published by Public Utilities Report Inc. 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:

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

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:

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

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 that has been tested. This is also because the use of adjusted betas rather than the use of raw betas incorporates some of the desired effect of using the ECAPM[1]. Thus, it is reasonable to apply a conservative alpha adjustment.

Appendix A contains a full 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:

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

Inserting 4.0% for the risk-free rate R_F, a MRP of 6.5% for $(R_M - R_F)$ and a beta of 0.72 in the above equation, the ROE is 9.1% without flotation costs and 9.4% with flotation costs discussed later in my testimony.

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. This is because the

1 1 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:

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. This is obvious from the fact that 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 comprised 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, as explained in Appendix A.

Q. PLEASE SUMMARIZE YOUR CAPM ESTIMATES.

A. The table below summarizes the common equity estimates obtained from the CAPM studies.

CAPM	% ROE
CAPM plain	9.0%
Empirical CAPM	9.4%

Q. HOW MUCH WEIGHT SHOULD BE ACCORDED TO THE CAPM

RESULTS UNDER CURRENT MARKET CIRCUMSTANCES?

A. The CAPM and ECAPM estimates are not significantly above the cost of new debt capital and likely understate the cost of equity capital under current unsettled capital market conditions. I believe that less weight should be accorded to the CAPM results under present circumstances for two reasons. First, because the betas employed in the CAPM analysis are estimated over five-year historical periods, the impact of the ongoing financial crisis is not yet fully captured in the five-year historical betas, and the betas do not reflect the current degree of volatility in the equity markets. Second, government interest rates have decreased substantially following the Federal Reserve's expansionary policies designed to jumpstart the stalled economy, thus lowering the CAPM results. At the same time, the cost of corporate debt and the cost of equity for utilities have increased significantly, as evidenced by the record high corporate yield spreads discussed earlier in my testimony, and by the DCF results for utilities that have increased by some 150-200 basis points in response to lower stock prices (higher dividend yields) following the financial crisis. The DCF analysis is presented below.

This anomaly between actual market costs and the estimation techniques used in this proceeding puts the Company at significant financing risk. As such, much less weight should be accorded to the CAPM method at present. As I mentioned above, there is a fundamental structural upward shift in risk aversion as capital markets are re-pricing risk, and capital has become, and will continue to be, more expensive for all non-government market participants over the next 18-24 months at least.

B. RISK PREMIUM ESTIMATE

Q. WHAT IS CURRENTLY HAPPENING IN THE DEBT AND EQUITY MARKETS?

A. As discussed earlier, in the past nine months, the financial markets, both in the U.S. and abroad, have become extremely volatile, unpredictable, and have displayed unusual behavior. The debt markets have witnessed record high yield spreads (the incremental yield over Treasury rates needed to issue debt) and a more severe differentiation between the spreads charged to companies with different levels of credit. In light of a fundamental structural upward shift in risk aversion as capital markets are re-pricing risk, capital has become, and will continue to be, more expensive for all market participants, including utilities.

Q. DR. MORIN, GIVEN THE CURRENT STATE OF THE CAPITAL MARKETS AT THIS TIME, IS A HISTORICAL RISK PREMIUM ANALYSIS USING GOVERNMENT BOND YIELDS APPROPRIATE?

A. No, I do not believe it is. Trends in utility cost of capital are directly reflected in their cost of debt and are not directly captured by a risk premium estimate tied to government bond yields. This is especially germane in the current financial crisis where corporate spreads have reached record levels. Because a utility's cost of capital is determined by its business and financial risks, it is reasonable to surmise that its cost of equity will track its cost of debt more closely than it will track the government bond yield. Therefore, in contrast to past testimonies I have performed a historical premium analysis using the utility bond yield instead of the government bond yield.

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

A. As a proxy for the risk premium applicable to the natural gas utility business, I estimated the historical risk premium for the utility industry with an annual time series analysis applied to the utility industry as a whole over the 1930-2007 period, using *Standard and Poor's Utility Index* as an industry proxy. The analysis is depicted on Attachment RAM-4. 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 utility bond return for that year.

As shown on Attachment RAM-4, the average risk premium over the period was 5.0% over historical long-term utility bond returns and also 5.0% over long-term utility bond yields. Given that the current yield on A-rated utility bonds is 6.3%, and using the historical estimate of 5.0%, the implied cost of equity for the average risk utility from this particular method is 6.3% + 5.0% = 11.3% without flotation costs and 11.6% with the flotation cost allowance. The need for a flotation cost allowance is discussed later in my testimony.

Q. DR. MORIN, ARE RISK PREMIUM STUDIES WIDELY USED?

A. Yes, they are. Risk Premium analyses are widely used by analysts, investors, economists, and expert witnesses. Most college-level corporate finance and/or investment management texts, including Investments by Bodie, Kane, and Marcus, McGraw-Hill Irwin, 2002, which is a recommended textbook for CFA (Chartered Financial Analyst) certification and examination, contain detailed conceptual and empirical discussion of the risk premium approach. The latter is typically recommended as one of the three leading methods of estimating the cost of capital. Professor Brigham's best-selling corporate finance textbook, for example, Corporate Finance: A Focused Approach, 3rd ed., South-Western, 2008, recommends the use of risk premium studies, among others. Techniques of risk premium analysis are widespread in investment community reports. Professional certified financial analysts are certainly well versed in the use of this method.

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

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 never invest any money.

C. 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 standard DCF model:

$$K_e = D_1/P_o + g$$

where: K_e = investors' expected return on equity.

D_1 = expected dividend at the end of the coming year.

P_o = current stock price.

g = expected growth rate of dividends, earnings, stock price, 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_o, 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 4 of my reference book, Regulatory Finance, and Chapter 8 of my latest textbook, The New Regulatory Finance. The standard DCF model requires the following main assumptions: a constant average growth trend for both dividends and earnings, a stable dividend payout policy, a discount rate in excess of the expected growth rate, and 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. I applied the DCF model to two proxy groups of companies for Duke Energy Kentucky's natural gas delivery operations: a group consisting of investment-grade dividend-paying natural gas utilities and a group consisting of investment-grade dividend-paying combination gas and electric utilities. In the case of both groups, the companies had to derive at least 50% of their revenues from regulated energy operations.

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 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 growth estimates developed by professional analysts employed by large investment brokerage institutions. 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 to investors 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 analysts are available from published investment newsletters and from systematic compilations of analysts' forecasts, such as those tabulated by Zacks Investment Research Inc. (Zacks). I used analysts' long-term growth forecasts contained in Zacks as proxies for investors' growth expectations in applying the DCF model. The latter are also conveniently provided in the Value Line software. I also used Value Line's growth forecast as a proxy.

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

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, Zacks Investment, First Call Thompson, and Multex provide comprehensive compilations of investors' earnings forecasts, to name some. 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 account for 65% of the ranking.

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

A. Historical growth rates have little relevance as proxies for future long-term growth at this time. They are downward-biased by the sluggish earnings performance in the last five/ten years, due to the structural transformation of the utility industry from a fully integrated regulated monopoly to a more competitive environment. Moreover, historical growth rates are somewhat redundant because historical growth patterns are already incorporated in analysts' growth forecasts that should be used in the DCF model.

Q. DID YOU CONSIDER ANY OTHER METHOD OF ESTIMATING EXPECTED GROWTH IN 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 is only accurate under the assumptions that the ROE is constant over time and that no new common stock is issued by the company, or if so, it is sold at book value. Second, and more importantly, the sustainable growth method contains a logic trap: the method requires an estimate of ROE to be implemented. But if the ROE input required by the model differs from the recommended return on equity, a fundamental contradiction in logic follows. Third, 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. This is because it is widely expected that some utilities will continue to lower their dividend payout ratio over the next several years in response to heightened business risk and the need to fund large construction programs over the next decade. In other words, earnings and dividends are not expected to grow at the same rate in the future.

Whenever the dividend payout ratio is expected to change, the intermediate growth rate in dividends cannot equal the long-term growth rate, because dividend/earnings growth must adjust to the changing payout ratio. The assumptions of constant perpetual growth and constant payout ratio are clearly not met. Thus, the implementation of the standard DCF model is of questionable relevance in this circumstance.

Dividend growth rates are unlikely to provide a meaningful guide to investors' growth expectations for utilities in general. This result is because utilities' dividend policies have become increasingly conservative as business risks in the industry have intensified steadily. Dividend growth has remained largely stagnant in past years as utilities are increasingly conserving financial resources in order to hedge against rising business risks. As a result, investors' attention has shifted from dividends to earnings. Therefore, 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.

Moreover, as a practical matter, while earnings growth forecasts are widely available, there are very few dividend growth forecasts.

Q. HOW DID YOU ESTIMATE DUKE ENERGY KENTUCKY'S COST OF

EQUITY WITH THE DCF MODEL?

A. I applied the DCF model to two proxy groups of companies for Duke Energy Kentucky: a group of investment-grade, dividend-paying, natural gas utilities, and a group of investment-grade dividend-paying combination electric and gas utilities with the majority of their revenues from regulated utility operations.

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).

From a conceptual viewpoint, the stock price to employ in calculating the dividend yield is the current price of the security at the time of estimating the cost of equity. This is because the current stock price provides 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, the current price reflects 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 evidence 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 latest edition of Value Line's VLIA software, dated April 2009. Basing dividend yields on average results from a large group of companies reduces the concern that idiosyncrasies of individual company stock prices will result in an unrepresentative dividend yield.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE NATURAL GAS UTILITIES GROUP USING ANALYSTS' GROWTH FORECASTS?

A. As a proxy for Duke Energy Kentucky's natural gas business, I have examined the expected returns of investment-grade dividend-paying natural gas distribution utilities contained in Value Line's natural gas distribution universe with a market value in excess of $100 million and with at least 50% of their revenues from regulated natural gas operations. The group is shown in Attachment RAM-5.

As shown on Column 2 of Attachment RAM-5, the average long-term growth forecast obtained from the Zacks corporate earnings database is 7.4% for the natural gas distribution group. Combining this growth rate with the average expected dividend yield of 4.6% shown in Column 3 produces an estimate of equity costs of 12.0% for the gas distribution group shown in Column 4. Recognition of flotation costs brings the cost of equity estimate to 12.2%, shown in Column 5.

Repeating the exact same procedure, only this time using Value Line's long-term earnings growth forecast of 5.3% instead of the Zacks consensus growth forecast, the cost of equity for gas distribution group is 9.8%, unadjusted for flotation costs. Adding an allowance for flotation costs brings the cost of equity estimate to 10.1%. This analysis is displayed on Attachment RAM-6.

Q. PLEASE DESCRIBE YOUR SECOND PROXY GROUP FOR THE COMPANY'S NATURAL GAS DISTRIBUTION 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, for 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 virtually identical allowed rates of return, attesting to their risk comparability.

For my second proxy group of companies, I started with a group of investment-grade utilities designated as "combination electric and gas" utilities by AUS Utility Reports, meaning that these companies all possess large amounts of energy distribution assets.

From this original group, I eliminated foreign companies, private partnerships, private companies, and companies below investment-grade (i.e., companies with a bond rating below Baa3), and companies without Value Line coverage. From this narrowed group, I further eliminated companies that do not pay dividends and companies with market capitalization less than $500 million (to minimize any stock price anomalies due to thin trading). Finally, I eliminated companies that derive less than 50% of their revenues from regulated electric utility operations. The final group of 21 companies is shown on Attachment RAM-7 Page 1. (Please note that I used the same group earlier in connection with beta estimates).

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE COMBINATION UTILITIES GROUP?

A. Attachment RAM-7 Page 2 provides the DCF results for the proxy group of combination utilities using the average long-term growth forecast obtained from Value Line. No growth projection was available for ALLETE. As shown on Column 2 of Attachment RAM-7, the average long-term growth forecast obtained from Value Line is 7.6% for this group. Adding this growth rate to the average expected dividend yield of 5.4% shown in Column 3 produces an estimate of equity costs of 13.0% for the group. Recognition of flotation costs brings the cost of equity estimate to 13.3%, shown in Column 5. Using the median instead of the average, the estimate of equity costs is 12.4% for the group.

Please see Attachment RAM-8 for the DCF results using the Zacks growth forecast for each company. Using the Zacks analysts' consensus forecast of long-term earnings instead of the Value Line forecast, the cost of equity for the group is 12.5% unadjusted for flotation cost. Recognition of flotation costs brings the cost of equity estimate to 12.8%, shown in Column 5 of Attachment RAM-8. Using the median instead of the average, the cost of equity estimate for the group is 12.4%, which is identical to the result of 12.4% obtained using the Value Line growth forecast.

Q. PLEASE SUMMARIZE YOUR DCF ESTIMATES.

A. The table below summarizes my DCF estimates for Duke Energy Kentucky.

DCF STUDY	ROE
DCF Natural Gas Utilities Value Line Growth	10.10%

DCF Natural Gas Utilities Zacks Growth	12.20%
DCF Combination Gas & Elec Utilities Value Line Growth	12.40%
DCF Combination Gas & Elec Utilities Zacks Growth	12.40%

Q. DR. MORIN, PLEASE NOW TURN TO 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 common equity capital is not free. Flotation costs associated with stock issues are exactly like 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 his marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (printing, legal, prospectus, *etc.*). 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 cost requires an upward adjustment to the allowed return on equity.

A simple 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 10.52%.

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 30 basis points, depending on the magnitude of the dividend yield component. To illustrate, dividing the average expected dividend yield of approximately 5.0% for utility stocks by 0.95 yields 5.3%, which is 30 basis points higher.

Sometimes, the argument is 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, 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 continue 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 plan, employees' savings plan, warrants, and stock dividend programs. Each item 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 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. 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 parent, 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 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. SUMMARY OF COST OF EQUITY RECOMMENDATION

Q. CAN YOU SUMMARIZE YOUR RESULTS AND RECOMENDATION?

A. To arrive at my final recommendation, I performed three risk premium analyses. For the first two risk premium studies, I applied the CAPM and an empirical approximation of the CAPM using current market data. The other risk premium analysis was performed on historical risk premium data from utility industry aggregate data. I also performed DCF analyses on two surrogates for the Company's natural gas delivery business. They are a group of investment-grade dividend-paying natural gas distribution utilities and a group of investment-grade combination electric and gas utilities with the majority of their revenues from regulated operations. The results from all the various tests are summarized in the table below.

METHODOLOGY	ROE
CAPM	9.00%
Empirical CAPM	9.40%
Historical Risk Premium Electric	11.60%
DCF Natural Gas Utilities Value Line Growth	10.10%
DCF Natural Gas Utilities Zacks Growth	12.20%
DCF Combination Elec Utilities Value Line Growth	12.40%
DCF Combination Elec Utilities Zacks Growth	12.40%

The results range from a low of 9.00% to a high of 12.40% with a midpoint of 11.0%. The average result from all the tests is also 11.0% and the truncated average is 11.1%. Based on these results, I believe that 11.0% is a reasonable, albeit conservative, estimate of the Company's cost of common equity. By virtue of the averaging process, it should be noted that for reasons discussed earlier, the CAPM results are accorded less weight than the DCF results. My recommended ROE also assumes the approval of the Company's test year capital structure.

Q. DR. MORIN, WHAT IS YOUR FINAL CONCLUSION REGARDING DUKE ENERGY KENTUCKY 'S COST OF COMMON EQUITY CAPITAL?

A. Based on the results of all my analyses, the application of my professional judgment, and the risk circumstances of Duke Energy Kentucky, it is my opinion that a just and reasonable return on the common equity capital of Duke Energy Kentucky's natural gas delivery operations in the state of Kentucky is 11.0%. Currently, capital markets are in a state of turmoil. It is important to note that my recommended return assumes that more stable circumstances will return to capital markets. However, the current market circumstances are anything but normal as I discussed earlier, and I deem my 11.0% ROE recommendation as barebones and extremely conservative.

Q. DR. MORIN, ARE YOU FAMILIAR WITH THE "ZONE OF REASONABLENESS" APPROACH IN AUTHORIZING ROEs?

A. Yes, I am. Under this approach, a ROE range rather than a single point estimate is authorized by the regulator. There are three advantages of authorizing a reasonable ROE range rather than a single point estimate. The first is that providing a zone of reasonableness for the authorized ROE permits the regulator the flexibility of weighing other factors, such as rate base, capital structure, and incentive provisions in its decision, with the assurance that the ROE estimate is within a reasonable range.

The second is that capital markets are volatile, and reasoned judgment is important. The results of mechanical approaches to estimating ROE are subject to measurement error, small sample bias, and turbulence in capital markets. Thus, estimating ROE for ratemaking purposes must take a longer-term and a more flexible view.

The third, and most important, is that a range serves as an incentive device by encouraging the company to minimize costs and operate efficiently so as to attain the top end of the authorized range. Allowing a range of permissible returns instead of a specific number, within which the utility's return could fluctuate, reaping some reward for success, and penalty for failure, provides utility management some incentive for efficiency. It does not entirely possess these incentives under traditional rate of return regulation.

Q. IN YOUR OPINION, DR. MORIN, WHAT WOULD CONSTITUTE A FAIR AND REASONABLE ROE RANGE FOR DUKE ENERGY KENTUCKY?

A. In my opinion, based on the variability of results displayed in the summary table above, a range of 10.5% - 11.5% is fair and reasonable.

Q. WHAT CAPITAL STRUCTURE ASSUMPTION UNDERLIES YOUR RECOMMENDED RETURN ON DUKE ENERGY KENTUCKY'S COMMON EQUITY CAPITAL?

A. My recommended return on common equity for Duke Energy Kentucky is predicated on the adoption of the Company's projected test year capital structure consisting of 50% common equity capital. Should the Commission decide to deviate from the capital structure, the empirical finance literature demonstrates that with each reduction (increase) in common equity ratio of 1%, the return on equity increases (decreases) by approximately 10 basis points, and conversely of course.

Q. DID YOU EXAMINE THE REASONABLENESS OF THE COMPANY'S TEST YEAR CAPITAL STRUCTURE?

A. Yes, I did. I have compared Duke Energy Kentucky's rate year capital structure with: 1) the capital structures adopted by regulators for gas utilities, and 2) the actual capital structures of comparable gas utilities.

The April 2009 edition of SNL Energy's (formerly Regulatory Research Associates) "*Regulatory Focus: Major Rate Case Decisions*" reports an average percentage of common equity in the adopted capital structure of 51% for gas utilities for 2008, which is nearly identical to the Company's 50% proposed common equity ratio in this case. I have also examined the actual capital structures of my comparable group of natural gas utilities as reported by Value Line. The average common equity ratio for the group is 54.6% as shown on Attachment RAM-9. I conclude that the Company's common equity ratio of 50% (exclusive of short term debt) is aggressive but reasonable for ratemaking purposes.

If the Commission imputes a capital structure consisting of substantially more or (less) debt than the Company's projected test year capital structure, the higher or (lower) common equity cost rate related to a changed common equity ratio should be reflected in the approach. If the Commission ascribes a capital structure different from the test year capital structure, which imputes a higher debt amount for example, the repercussions on equity costs must be recognized. It is a rudimentary tenet of basic finance that the greater the amount of financial risk borne by common shareholders, the greater the return required by shareholders in order to be compensated for the added financial risk imparted by the greater use of senior debt financing. In other words, the greater the debt ratio, the greater is the return required by equity investors. Both the cost of incremental debt and the cost of equity must be adjusted to reflect the additional risk associated with the more debt-heavy capital structure. Lower common equity ratios imply greater risk and higher capital cost, and conversely.

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

A. Yes. The capital market environment is extremely volatile at this time. Interest rates, security prices and risk premiums do change over time. 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. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

VERIFICATION

Province of Nova Scotia)
) SS:
County of Halifax)

The undersigned, Dr. Roger A. Morin, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Roger A. Morin

Dr. Roger A. Morin, Affiant

Subscribed and sworn to before me by Dr. Roger A. Morin on this 15 day of June, 2009.

MICHAEL R. CROWELL
A Commissioner of the Supreme
Court of Nova Scotia

NOTARY PUBLIC

Michael R. Crowell

My Commission Expires: N/A

RESUME OF ROGER A. MORIN

(Spring 2009)

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DATE OF BIRTH: 3/5/1945

PRESENT EMPLOYER: Georgia State University
Robinson College of Business
Atlanta, GA 30303

RANK: Emeritus Professor of Finance

HONORS: 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, 1979-2008
- Professor of Finance for Regulated Industry and Director, Center for the Study of Regulated Industry, Robinson College of Business, Georgia State University, 1985-2008
- Visiting Professor of Finance, Amos Tuck School of Business, Dartmouth College, Hanover, N.H., 1986
- Emeritus Professor of Finance, Georgia State University, 2007-9

OTHER BUSINESS ASSOCIATIONS

- Communications Engineer, Bell Canada, 1962-1967.
- Member of the 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.
- Executive Visions Inc., Board of Directors, Member
- Board of External Advisors, College of Business, Georgia State University, Member 1987-1991

PROFESSIONAL CLIENTS

AGL Resources

AT & T Communications

Alagasco - Energen

Alaska Anchorage Municipal Light & Power

Alberta Power Ltd.

Allete

Ameren

American Water Works Company

Ameritech

Arkansas Western Gas

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

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.

Chattanoogee Gas Company

Cincinnatti Gas & Electric

Cinergy Corp.

Citizens Utilities

City Gas of Florida

CN-CP Telecommunications

Commonwealth Telephone Co.

Columbia Gas System

Consolidated Natural Gas

Constellation Energy

Delmarva Power & Light Co

Deerpath Group

Detroit Edison Company

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

Jersey Central Power & Light

Kansas Power & Light

KeySpan Energy

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

Nevada Power Company

New Brunswick Power

Newfoundland Power Inc. - Fortis Inc.

New Market Hydro

New Tel Enterprises Ltd.

New York Telephone Co.

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.

NYNEX

Oklahoma G & E

Ontario Telephone Service Commission

Orange & Rockland

PNM Resources

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

Rochester Telephone

San Diego Gas & Electric

SaskPower

Sierra Pacific Power Company

Sierra Pacific Resources

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.

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 in a Restructured Environment
  Contemporary Issues in Utility Finance

- SNL Center for Financial Education. faculty member 2008-2009.
  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 Public Utility 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.

Colorado Public Utilities Board

Delaware Public Utility 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 Service Commission

Illinois Commerce Commission

Indiana Utility Regulatory Commission

Iowa Board of Public Utilities

Louisiana Public Service Commission

Maine Public Service Commission

Manitoba Board of Public Utilities

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

Nevada Public Service Commission

New Brunswick Board of Public Commissioners

New Hampshire Public Utility Commission

New Jersey Board of Public Utilities

New Mexico Public Regulatory Commission

New Orleans City Council

New York Public Service Commission

Newfoundland Board of Commissioners of Public Utilities

North Carolina Utilities Commission

Ohio Public Utilities Commission

Oklahoma State Board of Equalization

Ontario Telephone Service Commission

Ontario Energy Board

Pennsylvania Public Service Commission

Quebec Natural Gas Board

Quebec Regie de l'Energie

Quebec Telephone Service Commission

South Carolina Public Service Commission

Tennessee Regulatory Authority

Texas Public Utility Commission

Utah Public Service Commission

Virginia Public Service 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., D # U2334-86020

Quebec Telephone, Quebec PSC, 1986, 1987, 1992

Newfoundland L & P, Nfld. Brd. Publ Comm. 1987, 1991

Northwestern Bell, Minnesota PSC, #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, 1989

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

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

New Brunswick Power, 2002

Entergy New Orleans, 2002

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

Delmarva Power & Light Company 2005

Union Heat Power & Light 2005

Puget Sound Energy 2006, 2007, 2009

Cascade Natural Gas 2006

Entergy Arkansas 2006-7

Bangor Hydro 2006-7

Delmarva 2006-7

Potomac Electric Power Co. 2006, 2007

Detroit Edison Co. 2007, 2008

Nevada Power Co. 2007

Hawaiian Electric Co. 2006-7

Hawaii Elec & Light Co. 2007

Maui Electric Co. 2007

Ameren Union Electric 2008

Consolidated Edison of New York 2007-2008

Orange & Rockland 2007

Niagara Mohawk Power Corp 2008
Allete (Minnesota Power) 2007-2008

Sierra Pacific Power 2007-2008

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 Fla., 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, 1978.

"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. 1982, 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.

Chase Econometrics, Interactive Data Corp., Research Grant, $50,000 per annum, 1986-1989.

NATURAL GAS DISTRIBUTION UTILITIES
BETA ESTIMATES

	Company Name	Beta
1	AGL Resources	0.75
2	Atmos Energy	0.65
3	Chesapeake Utilities.	0.70
4	Laclede Group	0.65
5	New Jersey Resources	0.70
6	Nicor Inc.	0.70
7	Northwest Nat. Gas	0.60
8	Piedmont Natural Gas	0.70
9	South Jersey Inds.	0.75
10	Southwest Gas	0.75
11	WGL Holdings Inc.	0.75
	AVERAGE	**0.70**

Source: VLIA 04/2009

COMBINATION ELEC & GAS UTILITIES
BETA ESTIMATES

	Company Name	Beta
1	ALLETE	0.75
2	Alliant Energy	0.70
3	Ameren Corp.	0.80
4	Avista Corp.	0.70
5	CMS Energy Corp.	0.95
6	Consol. Edison	0.65
7	DTE Energy	0.70
8	Duke Energy	0.60
9	Empire Dist. Elec.	0.75
10	Entergy Corp.	0.75
11	Exelon Corp.	0.90
12	MGE Energy	0.70
13	Northeast Utilities	0.75
14	NorthWestern Corp	
15	NSTAR	0.70
16	Pepco Holdings	0.75
17	PG&E Corp.	0.65
18	Sempra Energy	0.95
19	TECO Energy	0.75
20	Wisconsin Energy	0.65
21	Xcel Energy Inc.	0.70
	AVERAGE	**0.74**

Source: VLIA 04/2009

Utility Industry Historical Risk Premium

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Year	Utlity A-Rated 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 Yields
1	1931	5.12%	1,000.00						
2	1932	6.46%	850.73	-149.27	51.20	-9.81%	-0.54%	9.27%	-7.00%
3	1933	6.32%	1,015.77	15.77	64.60	8.04%	-21.87%	-29.91%	-28.19%
4	1934	5.50%	1,098.72	98.72	63.20	16.19%	-20.41%	-36.60%	-25.91%
5	1935	4.61%	1,115.47	115.47	55.00	17.05%	76.63%	59.58%	72.02%
6	1936	4.08%	1,071.99	71.99	46.10	11.81%	20.69%	8.88%	16.61%
7	1937	3.98%	1,013.70	13.70	40.80	5.45%	-37.04%	-42.49%	-41.02%
8	1938	3.90%	1,011.04	11.04	39.80	5.08%	22.45%	17.37%	18.55%
9	1939	3.52%	1,054.23	54.23	39.00	9.32%	11.26%	1.94%	7.74%
10	1940	3.24%	1,040.98	40.98	35.20	7.62%	-17.15%	-24.77%	-20.39%
11	1941	3.07%	1,025.27	25.27	32.40	5.77%	-31.57%	-37.34%	-34.64%
12	1942	3.09%	997.03	-2.97	30.70	2.77%	15.39%	12.62%	12.30%
13	1943	2.99%	1,014.97	14.97	30.90	4.59%	46.07%	41.48%	43.08%
14	1944	2.97%	1,003.00	3.00	29.90	3.29%	18.03%	14.74%	15.06%
15	1945	2.87%	1,015.14	15.14	29.70	4.48%	53.33%	48.85%	50.46%
16	1946	2.71%	1,024.58	24.58	28.70	5.33%	1.26%	-4.07%	-1.45%
17	1947	2.78%	989.32	-10.68	27.10	1.64%	-13.16%	-14.80%	-15.94%
18	1948	3.02%	964.17	-35.83	27.80	-0.80%	4.01%	4.81%	0.99%
19	1949	2.90%	1,018.11	18.11	30.20	4.83%	31.39%	26.56%	28.49%
20	1950	2.79%	1,016.77	16.77	29.00	4.58%	3.25%	-1.33%	0.46%
21	1951	3.11%	952.61	-47.39	27.90	-1.95%	18.63%	20.58%	15.52%
22	1952	3.24%	980.97	-19.03	31.10	1.21%	19.25%	18.04%	16.01%
23	1953	3.49%	964.23	-35.77	32.40	-0.34%	7.85%	8.19%	4.36%
24	1954	3.16%	1,048.65	48.65	34.90	8.35%	24.72%	16.37%	21.56%
25	1955	3.22%	991.20	-8.80	31.60	2.28%	11.26%	8.98%	8.04%
26	1956	3.56%	951.65	-48.35	32.20	-1.62%	5.06%	6.68%	1.50%
27	1957	4.24%	908.92	-91.08	35.60	-5.55%	6.36%	11.91%	2.12%
28	1958	4.20%	1,005.38	5.38	42.40	4.78%	40.70%	35.92%	36.50%
29	1959	4.78%	925.83	-74.17	42.00	-3.22%	7.49%	10.71%	2.71%
30	1960	4.78%	1,000.00	0.00	47.80	4.78%	20.26%	15.48%	15.48%
31	1961	4.62%	1,020.74	20.74	47.80	6.85%	29.33%	22.48%	24.71%
32	1962	4.54%	1,010.44	10.44	46.20	5.66%	-2.44%	-8.10%	-6.98%
33	1963	4.39%	1,019.83	19.83	45.40	6.52%	12.36%	5.84%	7.97%

34	1964	4.52%	983.00	-17.00	43.90	2.69%	15.91%	13.22%	11.39%
35	1965	4.58%	992.20	-7.80	45.20	3.74%	4.67%	0.93%	0.09%
36	1966	5.39%	901.59	-98.41	45.80	-5.26%	-4.48%	0.78%	-9.87%
37	1967	5.87%	943.94	-56.06	53.90	-0.22%	-0.63%	-0.41%	-6.50%
38	1968	6.51%	928.99	-71.01	58.70	-1.23%	10.32%	11.55%	3.81%
39	1969	7.54%	894.48	-105.52	65.10	-4.04%	-15.42%	-11.38%	-22.96%
40	1970	8.69%	891.81	-108.19	75.40	-3.28%	16.56%	19.84%	7.87%
41	1971	8.16%	1,051.83	51.83	86.90	13.87%	2.41%	-11.46%	-5.75%
42	1972	7.72%	1,044.47	44.47	81.60	12.61%	8.15%	-4.46%	0.43%
43	1973	7.84%	987.98	-12.02	77.20	6.52%	-18.07%	-24.59%	-25.91%
44	1974	9.50%	852.57	-147.43	78.40	-6.90%	-21.55%	-14.65%	-31.05%
45	1975	10.09%	949.69	-50.31	95.00	4.47%	44.49%	40.02%	34.40%
46	1976	9.29%	1,072.11	72.11	100.90	17.30%	31.81%	14.51%	22.52%
47	1977	8.61%	1,064.35	64.35	92.90	15.72%	8.64%	-7.08%	0.03%
48	1978	9.29%	938.71	-61.29	86.10	2.48%	-3.71%	-6.19%	-13.00%
49	1979	10.49%	900.41	-99.59	92.90	-0.67%	13.58%	14.25%	3.09%
50	1980	13.34%	802.50	-197.50	104.90	-9.26%	15.08%	24.34%	1.74%
51	1981	15.95%	843.97	-156.03	133.40	-2.26%	11.74%	14.00%	-4.21%
52	1982	15.86%	1,005.41	5.41	159.50	16.49%	26.52%	10.03%	10.66%
53	1983	13.66%	1,149.59	149.59	158.60	30.82%	20.01%	-10.81%	6.35%
54	1984	14.03%	975.38	-24.62	136.60	11.20%	26.04%	14.84%	12.01%
55	1985	12.47%	1,113.97	113.97	140.30	25.43%	33.05%	7.62%	20.58%
56	1986	9.58%	1,255.25	255.25	124.70	37.99%	28.53%	-9.46%	18.95%
57	1987	10.10%	955.69	-44.31	95.80	5.15%	-2.92%	-8.07%	-13.02%
58	1988	10.49%	967.63	-32.37	101.00	6.86%	18.27%	11.41%	7.78%
59	1989	9.77%	1,062.76	62.76	104.90	16.77%	47.80%	31.03%	38.03%
60	1990	9.86%	992.20	-7.80	97.70	8.99%	-2.57%	-11.56%	-12.43%
61	1991	9.36%	1,044.85	44.85	98.60	14.34%	14.61%	0.27%	5.25%
62	1992	8.69%	1,063.03	63.03	93.60	15.66%	8.10%	-7.56%	-0.59%
63	1993	7.59%	1,112.26	112.26	86.90	19.92%	14.41%	-5.51%	6.82%
64	1994	8.31%	930.36	-69.64	75.90	0.63%	-7.94%	-8.57%	-16.25%
65	1995	7.89%	1,041.91	41.91	83.10	12.50%	42.15%	29.65%	34.26%
66	1996	7.75%	1,014.12	14.12	78.90	9.30%	3.14%	-6.16%	-4.61%
67	1997	7.60%	1,015.30	15.30	77.50	9.28%	24.69%	15.41%	17.09%
68	1998	7.04%	1,059.61	59.61	76.00	13.56%	14.82%	1.26%	7.78%
69	1999	7.62%	940.94	-59.06	70.40	1.13%	-8.85%	-9.98%	-16.47%
70	2000	8.24%	939.72	-60.28	76.20	1.59%	59.70%	58.11%	51.46%
71	2001	7.78%	1,046.28	46.28	82.40	12.87%	-30.41%	-43.28%	-38.19%
72	2002	7.37%	1,042.55	42.55	77.80	12.03%	-30.04%	-42.07%	-37.41%
73	2003	6.58%	1,087.17	87.17	73.70	16.09%	26.11%	10.02%	19.53%
74	2004	6.16%	1,047.92	47.92	65.80	11.37%	24.22%	12.85%	18.06%
75	2005	5.65%	1,060.65	60.65	61.60	12.22%	16.79%	4.57%	11.14%
76	2006	6.07%	951.73	-48.27	56.50	0.82%	20.95%	20.13%	14.88%
77	2007	6.07%	1,000.00	0.00	60.70	6.07%	19.36%	13.29%	13.29%

78			
79	**Mean**	**5.0%**	**5.0%**

Source: Bloomberg Web site: Standard & Poors Utility Stock Index % Annual Change, Dec. to Dec

Bond yields from Bloomberg

DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	AGL Resources	5.47	5.33	5.76	11.09	11.39
2	Atmos Energy	5.36	6.00	5.68	11.68	11.98
3	Chesapeake Utilities	4.60	8.00	4.97	12.97	13.23
4	Laclede Group	3.31	10.00	3.64	13.64	13.83
5	Nicor Inc.	5.33	6.53	5.68	12.21	12.51
6	Northwest Nat. Gas	3.68	7.50	3.96	11.46	11.66
7	Piedmont Natural Ga:	3.97	7.33	4.26	11.59	11.82
8	South Jersey Inds.	3.18	8.60	3.45	12.05	12.24
9	Southwest Gas	3.60	8.00	3.89	11.89	12.09
10	WGL Holdings Inc.	4.38	6.67	4.67	11.34	11.59
	AVERAGE	**4.29**	**7.40**	**4.60**	**11.99**	**12.23**

Notes:
Column 1: Value Line Investment Analyzer Apr 2009
Column 2: Zacks long-term earnings growth forecast, 04/2009
Column 3 = Column 1 times (1 + Column 2/100)

NATURAL GAS UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Value Line Proj Growth (2)	Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	AGL Resources	5.47	3.00	5.63	8.63	8.93
2	Atmos Energy	5.36	4.50	5.60	10.10	10.40
3	Chesapeake Utilities	4.60	8.00	4.97	12.97	13.23
4	Laclede Group	3.31	4.50	3.46	7.96	8.14
5	Nicor Inc.	5.33	4.00	5.54	9.54	9.83
6	Northwest Nat. Gas	3.68	5.50	3.88	9.38	9.59
7	Piedmont Natural Gas	3.97	7.50	4.27	11.77	11.99
8	South Jersey Inds.	3.18	6.00	3.37	9.37	9.55
9	Southwest Gas	3.60	6.50	3.83	10.33	10.54
10	WGL Holdings Inc.	4.38	3.50	4.53	8.03	8.27
	AVERAGE	**4.29**	**5.30**	**4.51**	**9.81**	**10.05**

Notes:
Column 1, 2: Value Line Investment Analyzer, 04/2009
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 2 + Column 3

COMBINATION ELEC & GAS UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)
1	ALLETE	5.6	
2	Alliant Energy	5.1	6.0
3	Ameren Corp.	7.3	4.0
4	Avista Corp.	4.0	9.0
5	CMS Energy Corp.	4.4	11.0
6	Consol. Edison	5.7	1.0
7	DTE Energy	6.2	5.0
8	Duke Energy	6.1	7.0
9	Empire Dist. Elec.	7.1	10.0
10	Entergy Corp.	3.9	7.5
11	Exelon Corp.	3.8	8.0
12	MGE Energy	4.5	5.5
13	Northeast Utilities	3.7	12.0
14	NorthWestern Corp	6.5	10.0
15	NSTAR	4.4	7.5
16	Pepco Holdings	5.9	11.0
17	PG&E Corp.	4.3	7.0
18	Sempra Energy	3.6	7.0
19	TECO Energy	6.6	7.5
20	Wisconsin Energy	3.0	8.0
21	Xcel Energy Inc.	5.2	7.5

Notes:
Column 1, 2: Value Line Investment Analyzer, 4/2009
No growth projection is available for ALLETE

COMBINATION ELEC & GAS UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Alliant Energy	5.1	6.0	5.4	11.4	11.7
2	Ameren Corp.	7.3	4.0	7.6	11.6	12.0
3	Avista Corp.	4.0	9.0	4.4	13.4	13.6
4	CMS Energy Corp.	4.4	11.0	4.9	15.9	16.1
5	Consol. Edison	5.7	1.0	5.8	6.8	7.1
6	DTE Energy	6.2	5.0	6.6	11.6	11.9
7	Duke Energy	6.1	7.0	6.5	13.5	13.9
8	Empire Dist. Elec.	7.1	10.0	7.8	17.8	18.2
9	Entergy Corp.	3.9	7.5	4.1	11.6	11.9
10	Exelon Corp.	3.8	8.0	4.1	12.1	12.3
11	MGE Energy	4.5	5.5	4.8	10.3	10.5
12	Northeast Utilities	3.7	12.0	4.1	16.1	16.3
13	NorthWestern Corp	6.5	10.0	7.2	17.2	17.5
14	NSTAR	4.4	7.5	4.7	12.2	12.5
15	Pepco Holdings	5.9	11.0	6.6	17.6	17.9
16	PG&E Corp.	4.3	7.0	4.6	11.6	11.9
17	Sempra Energy	3.6	7.0	3.8	10.8	11.0
18	TECO Energy	6.6	7.5	7.1	14.6	15.0
19	Wisconsin Energy	3.0	8.0	3.2	11.2	11.4
20	Xcel Energy Inc.	5.2	7.5	5.6	13.1	13.4
	AVERAGE	**5.1**	**7.6**	**5.4**	**13.0**	**13.3**
	MEDIAN					**12.4**

Notes:

Column 1, 2: Value Line Investment Analyzer, 4/2009

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

Column 4 = Column 3 + Column 2

Column 5 = (Column 3 /0.95) + Column 2

Note: No growth forecast available for ALLETE

COMBINATION ELEC & GAS UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	ALLETE	5.6	6.5	6.0	12.5	12.8
2	Alliant Energy	5.1	6.0	5.4	11.4	11.7
3	Ameren Corp.	7.3	4.0	7.6	11.6	12.0
4	Avista Corp.	4.0	8.7	4.3	13.0	13.2
5	CMS Energy Corp	4.4	6.5	4.7	11.2	11.4
6	Consol. Edison	5.7	3.5	5.9	9.4	9.7
7	DTE Energy	6.2	6.0	6.6	12.6	13.0
8	Duke Energy	6.1	5.0	6.4	11.4	11.7
9	Entergy Corp.	3.9	7.3	4.1	11.4	11.6
10	Exelon Corp.	3.8	9.0	4.1	13.1	13.3
11	Northeast Utilities	3.7	9.5	4.0	13.5	13.7
12	NorthWestern Cor	6.5	10.0	7.2	17.2	17.5
13	NSTAR	4.4	7.4	4.7	12.1	12.4
14	Pepco Holdings	5.9	7.0	6.4	13.4	13.7
15	PG&E Corp.	4.3	7.1	4.6	11.7	12.0
16	Sempra Energy	3.6	6.5	3.8	10.3	10.5
17	TECO Energy	6.6	11.2	7.3	18.5	18.9
18	Wisconsin Energy	3.0	9.0	3.2	12.2	12.4
19	Xcel Energy Inc.	5.2	6.0	5.5	11.5	11.8
	AVERAGE	**5.0**	**7.2**	**5.4**	**12.5**	**12.8**
	MEDIAN					**12.4**

Notes:
Column 1: Value Line Investment Analyzer, 4/2009
Column 2: Zacks Investment Research, 4/2009
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

No growth projections available for Empire, MGE Energy.

Natural Gas Utilities
Common Equity Ratios

	Company Name	% Com Eq
1	AGL Resources	49.8
2	Atmos Energy	48.0
3	Chesapeake Utilities	65.4
4	Laclede Group	55.5
5	Nicor Inc.	69.0
6	Northwest Nat. Gas	53.7
7	Piedmont Natural Gas	52.8
8	South Jersey Inds.	57.3
9	Southwest Gas	41.9
10	WGL Holdings Inc.	62.4
	AVERAGE	**55.6**
	MEDIAN	54.6

Source: VLIA April 2009

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

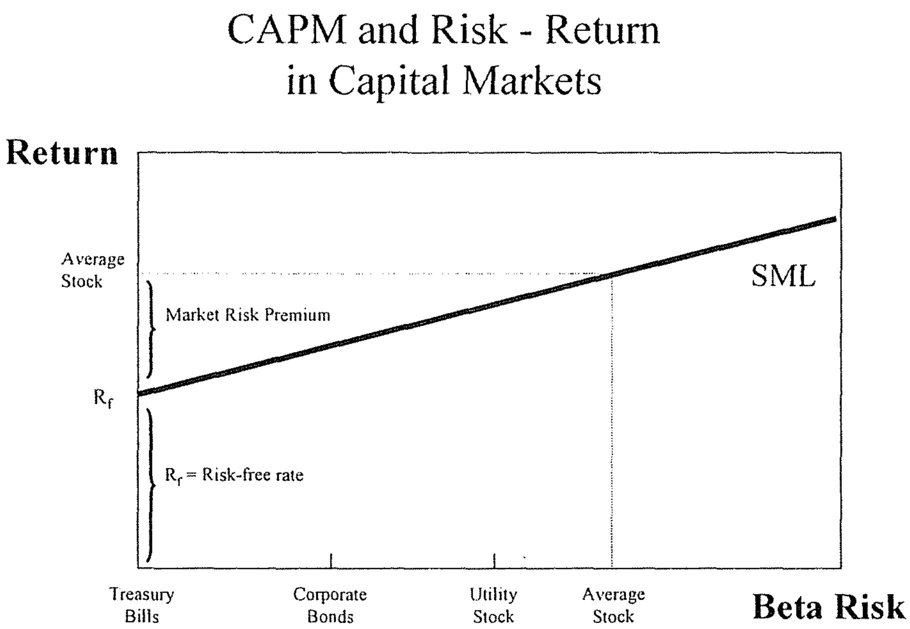
Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is:

$$K = R_F + \beta(R_M - R_F) \qquad (1)$$

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:

$$K = R_F + \beta \times MRP \qquad (2)$$

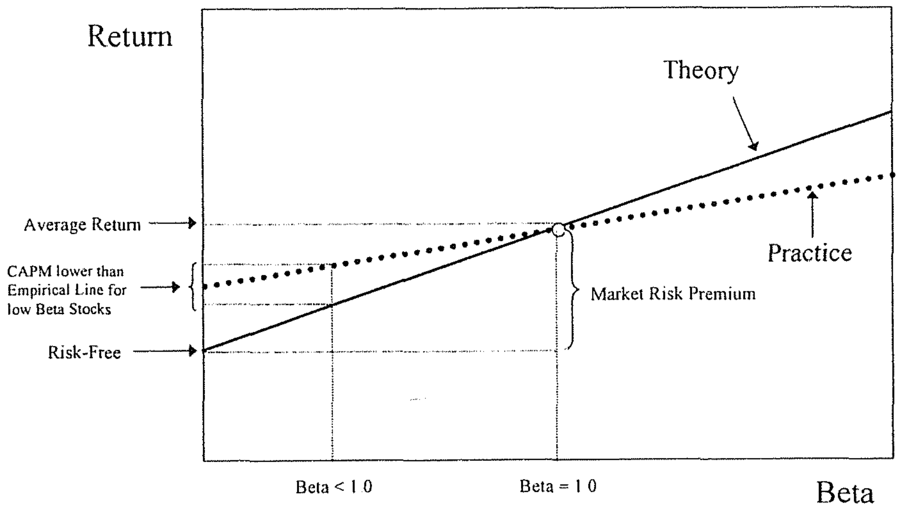
The CAPM risk-return relationship is depicted in the figure below and is typically labeled as the Security Market Line (SML) by the investment community.



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 [Regulatory Finance, Public Utilities Report Inc., Arlington, VA, 1994].

Risk vs Return

Theory vs. Practice



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:

$$K = R_F + \alpha + \beta\ (MRP - \alpha) \tag{3}$$

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:

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

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

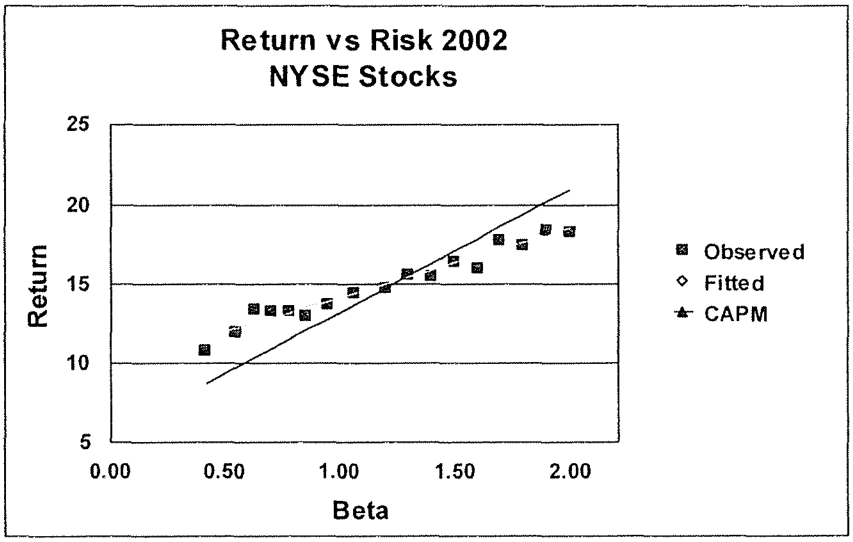
Given the observed magnitude of alpha, the empirical evidence indicates that the risk-return relationship is flatter than that predicted by the CAPM. Typical of the empirical evidence is the findings cited in Morin (1989) over the period 1926-1984 indicating that the observed expected return on a security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

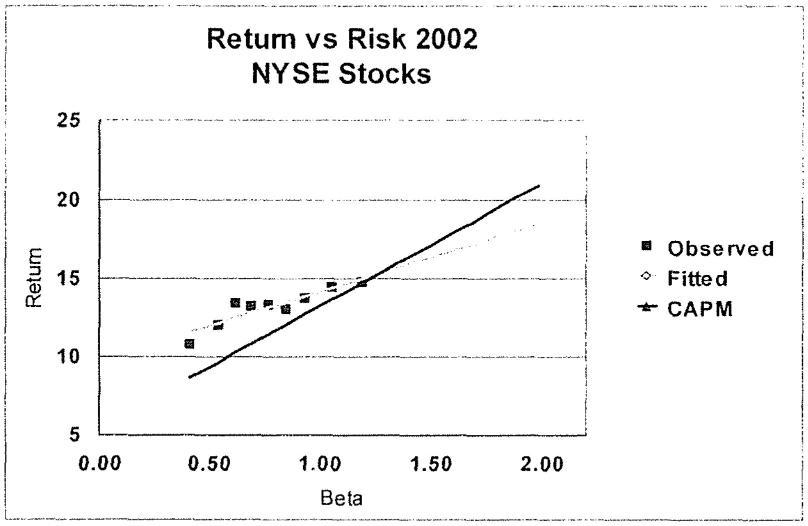
CAPM vs ECAPM



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

[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.

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).

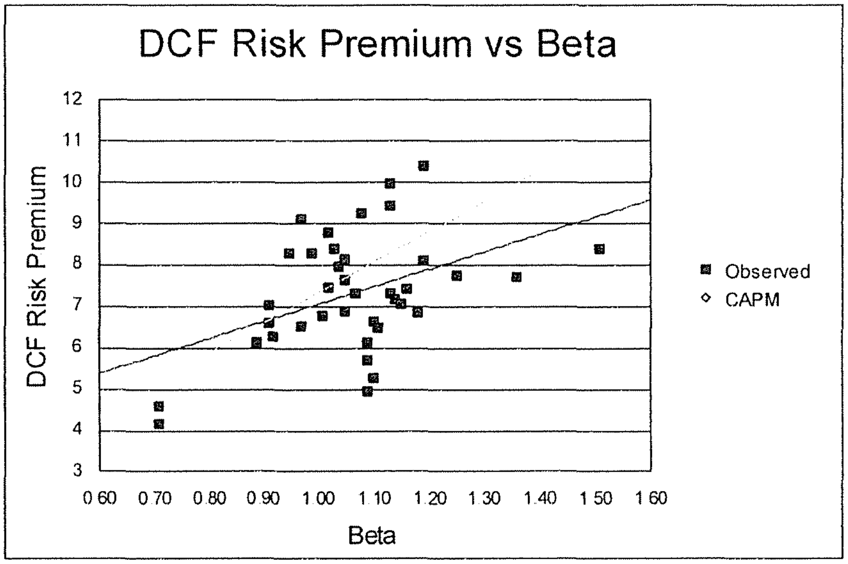
The table below, drawn from HMMO Table 4, displays the average estimate prospective risk premium (Column 2) by industry and the corresponding beta estimate for that industry, both in raw form (Column 3) and adjusted form (Column 4). The latter were calculated with the traditional Value Line – Merrill 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 (1)	DCF Risk Premium (2)	Raw Industry Beta (3)	Adjusted Industry Beta (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

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:

$$K = R_F + \alpha + \beta \,(MRP - \alpha) \qquad (5)$$

or, alternatively by the following equivalent relationship:

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

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:

$$K = R_F + \alpha + \beta \,(MRP - \alpha)$$
$$K = 5\% + 2\% + 0.80(7\% - 2\%)$$
$$= 11\%$$

[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:

$$K = 5\% + 0.25 \times 7\% + 0.75 \times 0.80 \times 7\%$$
$$= 11\%$$

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.

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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.

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_0 equals B_0, the book value per share, then the company's required return is:

$$r = D_1/B_0 + g$$

Denoting the percentage flotation costs 'f', proceeds per share B_0 are related to market price P_0 as follows:

$$P - fP = B_0$$

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

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

$$r = D_1/P(1-f) + g$$

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 AN ADJUSTMENT	)	
OF GAS RATES OF	)	CASE NO. 2009-00202
DUKE ENERGY KENTUCKY, INC.	)	

DIRECT TESTIMONY OF

ROBERT M. PARSONS

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

July 1, 2009

269095

TABLE OF CONTENTS

ATTACHMENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert M. Parsons. 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, an affiliate service company of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company), as Rates Manager.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I received a Bachelor of Business Administration Degree from The University of Cincinnati (UC) and a Master of Business Administration Degree from Xavier University. I am a Certified Public Accountant and a member of the American Institute of Certified Public Accountants and the Ohio Society of Certified Public Accountants.

Upon graduating from UC, I became employed by The Cincinnati Gas & Electric Company, the predecessor of Duke Energy Ohio, Inc. (Duke Energy Ohio). I have been continuously employed by Duke Energy Ohio or Duke Energy since 1975, and I have held positions in Treasury, Internal Audit, Tax, Fixed Assets and, since October 1998, in the Rate Department. I have been Rates Manager since July 2008.

Q. PLEASE SUMMARIZE YOUR DUTIES AS RATES MANAGER.

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

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

A. Yes. I provided oral testimony on cross-examination in support of an adjustment to Duke Energy Kentucky's Accelerated Main Replacement Rider (Rider AMRP) sometime between 2003 and 2005.

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

A. I sponsor and support the following filing schedules: Schedules A, B-1, B-5, B-5.1, B-6, C-1 through C-2.2, D-1, D-2.1 through D-2.28, E-1, E-2, F-1 through F-7, G-1 through G-3, H, and pages 2, 4, and 5 of Schedule K. These schedules satisfy filing requirements (FR) 10(10)(a) through 10(10)(h) and 10(10)(k) and were all prepared by me or under my direction and supervision. In addition, I will discuss other operating income and rate base issues raised in prior proceedings. I also sponsor and support filing requirements FRs 10(8)(a), 10(8)(b), 10(8)(c), 10(8)(f), and 10(9)(t). Finally, I will discuss the Company's proposal to recover the net charge offs related to the gas cost billed to customers and its proposal to include the carrying costs on gas inventory in the Gas Cost Adjustment Rider.

II. <u>TEST PERIOD AND RATE BASE</u>

Q. WHAT IS THE TEST PERIOD IN THIS PROCEEDING?

A. The Company has elected to use a forecasted test period in this proceeding. The forecasted test period reflects the twelve months ending January 31, 2011, adjusted for known and measurable changes, and a base period of twelve months ending September 30, 2009. The base period consists of six months of actual data, through March 31, 2009, and the remaining six months consists of forecasted data.

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

A. The Company determined rate base and capitalization using a 13-month average for the forecasted test period ending January 31, 2011. The base period rate base and capitalization represent end-of-period balances.

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

A. Yes. Pursuant to the Kentucky Public Service Commission rules, "the forecast contains the same assumptions and methodologies as used in the forecast prepared for use by management." As described by Duke Energy Kentucky witness Stephen R. Lee, the base and forecasted test periods were developed using the same methods applied in the Company's annual budgeting process. The first six months of the base period are actual results and were taken from the Company's books and records.

III. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE SCHEDULE A.

A. Schedule A is the overall financial summary for both the base period and the forecasted test period at present rates. Based on the filing in this proceeding, as adjusted, the Company's gas operations are projected to earn a return on capitalization of 3.48% for the forecasted test period, which is considerably less than the 7.671% return requested in this proceeding. In order to achieve the appropriate return on capitalization, Duke Energy Kentucky's base gas revenues must increase $17,494,129, as shown in Schedule A.

Q. HOW WAS TOTAL CAPITALIZATION FROM SCHEDULE J ALLOCATED TO GAS OPERATIONS ON SCHEDULE A?

A. The Company determined the amount of total capitalization allocated to gas operations using the methodology approved by the Commission in prior Duke Energy Kentucky rate proceedings. This process involves applying a gas rate base ratio for the base and forecasted test periods, as determined on WPA-1b and WPA-1d, to total company capitalization, as shown on Schedule J-1, adjusted for non-jurisdictional rate base items. The calculation of allocated capitalization for the base and forecasted test periods are shown on WPA-1a and WPA-1c, respectively.

Q. WHAT ARE THE MAJOR FACTORS THAT PREVENT DUKE ENERGY KENTUCKY FROM EARNING A FAIR RETURN ON THE CAPITAL INVESTED IN THE GAS SYSTEM?

A. As discussed in the testimony of Duke Energy Kentucky witness William Don Wathen Jr., The Company's significant increase in gas plant, mainly due to its investment in the Accelerated Main Replacement Program (AMRP), have impaired its ability to earn a fair and reasonable return. A smaller but significant factor has been a decline in volumetric gas sales. It is noteworthy that operation and maintenance (O&M) expenses have not changed significantly since the Company's last gas base rate case due to the Company's ongoing efforts to reduce costs. Duke Energy Kentucky witness Mr. Gary J. Hebbeler describes the Company's efforts to reduce costs in his testimony.

Q. PLEASE DESCRIBE SCHEDULE B-1.

A. Schedule B-1 is the rate base summary for both the base and forecasted test periods and is supported by various schedules in Section B of the Company's filing. The plant in service, reserve for accumulated depreciation and amortization, and construction work in progress for the base and forecasted test periods were summarized from Schedules B-2, B-3, and B-4, as supported by Duke Energy Kentucky witness Ms. Brenda R. Melendez. The working capital component was summarized from Schedule B-5, and other items of rate base were obtained from Schedule B-6. The jurisdictional gas rate base for the forecasted test period as contained in Schedule B-1 is $253,125,967.

Q. PLEASE DESCRIBE SCHEDULE B-5.

A. Schedule B-5 is a summary of the jurisdictional working capital calculation for both the base and forecasted test period based on the Commission's traditional methodology. The calculation includes a cash element of working capital, material and supplies inventory, gas enricher liquids, and prepayments.

Q. PLEASE DESCRIBE SCHEDULE B-5.1.

A. Schedule B-5.1 reflects the itemized miscellaneous working capital items for both the base and forecasted test periods. The forecasted test period is presented for both the 13-month average and the end of period balance.

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 test period, and the end of period balance for both the base and forecasted test periods. The inventory consists 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 gas working capital for the forecasted test period is ($95,694).

Q. PLEASE EXPLAIN THE GAS ENRICHER LIQUIDS ON SCHEDULE B-5.1.

A. The balance of gas enricher liquids shown on Schedule B-5.1 represents the 13-month average for the forecasted test period, and the end of period balance for both the base and forecasted test periods, respectively. Consistent with the adjustment made to Gas Plant devoted to other than Kentucky customers on WPB-2.2a, 65% of the gas enricher liquids amount has been eliminated from the working capital calculation. The jurisdictional amount included in the forecasted test period is $355,804.

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

A. The prepayments shown on Schedule B-5.1 represent the 13-month average for the forecasted test period, and the end of period balance for both the base and forecasted test periods, respectively. These prepayments are expenditures that, as required by the vendor or taxing authority, must be paid in advance prior to being charged to operations and, therefore, represent a working capital requirement. As can be seen on Schedule B-5.1, all of the gas prepayments included in the forecasted test period working capital computation are considered non-jurisdictional. This is due to the fact that all of the prepayments are either related to the electric operations of the business or, as in the case of the Kentucky Public Service Commission maintenance taxes, are considered non-jurisdictional because of past precedent of the Commission.

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 test periods. It represents the financing required 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 cash working capital is $2,612,875 and for the forecasted test period cash working capital is calculated to be $2,371,199.

Q. WHY HAS THE GAS STORED UNDERGROUND BEEN ELIMINATED FROM THE JURISDICTIONAL WORKING CAPITAL ON SCHEDULE B-5.1?

A. As explained in the testimony of Mr. Wathen, the Company is proposing to move the carrying costs on gas stored underground from base rates to its Gas Cost Adjustment Rider (Rider GCA). Therefore, contingent on the Commission's acceptance of the Company's proposal to move the carrying costs to Rider GCA, the13-month average balance of gas stored underground shown on Schedule B-5.1 is being considered non-jurisdictional. If this proposal is not accepted, the full amount of the 13-month average balance should be included in the forecasted Gas jurisdictional working capital. I will discuss the specifics of the Company's proposal later in my testimony.

Q. PLEASE DESCRIBE SCHEDULE B-6.

A. Schedule B-6 presents certain deferred credits, accumulated deferred income taxes (ADIT), and other items that form the adjustments to rate base as summarized on Schedule B-1. On this schedule, the first column contains balances as of the end of the base period (page 1 of 2) and the 13-month average balance for the forecasted test period (page 2 of 2). The second and third columns allocate the balances to jurisdictional customers. Duke Energy Kentucky's gas operations are 100% jurisdictional, as indicated in column three. The fourth column contains adjustments to the balances and a footnote reference describing the adjustment, and the fifth column is the jurisdictional amount included in rate base. The balances shown are: Customer Advances for Construction, Account 252; Investment Tax Credits, Account 255; and Deferred Income Taxes, Account Nos. 190, 281, 282, and 283.

Q. WHY ARE SOME OF THESE AMOUNTS EXCLUDED FROM RATE BASE?

A. There are several reasons for items to be excluded from rate base. First, with regard to the investment tax credits, certain amounts cannot be used as a cost of service reduction in accordance with the Internal Revenue Code. Second, certain amounts were eliminated to be consistent with other adjustments proposed by the Company.

In addition, certain of the Company's gas facilities are not used exclusively to serve Kentucky customers. Liberalized Depreciation ADIT and Accumulated Deferred Investment Tax Credits related to this non-jurisdictional gas plant were eliminated from jurisdictional gas rate base in determining the rate base ratio, consistent with the development of the ratio in prior proceedings. The items and corresponding amounts to be excluded from jurisdictional gas rate base are shown on WPB-6c and WPB-6d. The ratio of gas plant devoted to other than Duke Energy Kentucky's customers is based on a methodology accepted by the Commission in Case No. 2005-00042.

Q. PLEASE DESCRIBE SCHEDULE C-1.

A. Schedule C-1 is a jurisdictional operating income summary for the forecasted test period ended January 31, 2011. This schedule includes the operating income summary at both current and proposed rates. It assumes that the Commission allows the total amount of the requested gas revenue increase of $17,494,336. The forecasted return at current rates was summarized from Schedule C-2 and the proposed increase was obtained from Schedule M. The forecasted return at proposed rates was developed by adding the proposed increase and the related expenses and taxes on the proposed increase to the forecasted return at current rates. The rate base as shown on this schedule is calculated on Schedule B-1. The capitalization allocated to gas operations is calculated on workpaper WPA-1c.

Q. PLEASE DESCRIBE SCHEDULE C-2.

A. Schedule C-2 is an adjusted jurisdictional operating income statement. In order to develop the forecasted test year that is appropriate for ratemaking, a two-step process was required. First, it was necessary to show the adjustments required to transform the financial data for the base period into the forecasted test period. Second, it was necessary to adjust the forecasted test period data to reflect any fixed, known and measurable adjustments required to ensure that the revenues and expenses to be recovered in rates are representative of the expected costs to serve Duke Energy Kentucky's gas customers on an ongoing basis.

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

Q. PLEASE DESCRIBE SCHEDULE C-2.1.

A. Schedule C-2.1 sets forth the detail of the Company's gas operating results for both the base and forecasted test periods. The gas operating results, shown on Schedule C-2.1, are listed by account and are summarized on Schedule C-2.

Q. PLEASE DESCRIBE SCHEDULE C-2.2.

A. Schedule C-2.2 contains a monthly comparison of gas revenue and expense in the base period to the 12-month period prior to the beginning of the base period by Federal Energy Regulatory Commission (FERC) account. Variances from prior periods are indicated in dollars and in percent.

Q. PLEASE DESCRIBE SCHEDULE D-1.

A. Schedule D-1 is a summary of the adjustments to base and forecasted test period operating revenues and operating expenses as set forth in Schedules D-2.1 through D-2.28. These *pro forma* adjustments to the base period data are necessary to derive the forecasted test period amounts, which include the fixed, known, and measurable adjustments required to ensure that revenue and expenses included in rates are set at the appropriate level to cover the cost of providing service to Duke Energy Kentucky's gas customers.

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

A. The adjustments shown in Schedules D-2.1 through D-2.14 reflect the normal budgetary changes that are expected to occur from the base period through the forecasted test period. The remaining adjustments, shown in Schedules D-2.15 through D-2.28, present *pro forma* adjustments to the forecasted test period data required to ensure that the correct amount of revenue and expense is included in rates at the proper ongoing level. Some costs, although reflected in the normal forecasting process, are not recoverable from Duke Energy Kentucky's customers. Other adjustments were made to reflect traditional ratemaking methodology (*e.g.*, amortizing a regulatory asset to reflect the Commission's prior orders). The reflection of a proper cost level is necessary in order to give the Company a reasonable opportunity to earn its authorized return and to ensure that customers are not paying for more than the cost of providing service. Ignoring appropriate adjustments to the test period used for setting rates puts the Company at risk for potentially under-recovering its ongoing costs and also puts customers at risk of overpaying for service.

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

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

Q. PLEASE DESCRIBE SCHEDULE D-2.1.

A. Schedule D-2.1 adjusts base period revenue to the amount included in the forecasted test period. The adjustment results in a net revenue increase of $5,863,426. The federal and state income tax effects are shown on Schedule D-1.

Q. PLEASE DESCRIBE SCHEDULE D-2.2.

A. Schedule D-2.2 adjusts purchased gas costs to the amount included in the forecasted test period. The effect of the adjustment on Duke Energy Kentucky's gas operations is a decrease in pre-tax operating expenses of $1,290,670.

Q. PLEASE DESCRIBE SCHEDULE D-2.3.

A. Schedule D-2.3 adjusts base period other production expenses to the amount included in the forecasted test period. The effect of the adjustment on gas operations is an increase in pre-tax operating expenses of $40,363.

Q. PLEASE DESCRIBE SCHEDULE D-2.4.

A. Schedule D-2.4 adjusts base period other gas supply expenses to the amount included in the forecasted test period. The effect of the adjustment on gas operations is an increase in pre-tax operating expenses of $146,105.

Q. PLEASE DESCRIBE SCHEDULE D-2.5.

A. Schedule D-2.5 adjusts base period transmission expenses to the amount included in the forecasted test period. Since the Company has no gas transmission expense in either the base or forecasted test period, no adjustment is necessary.

Q. PLEASE DESCRIBE SCHEDULE D-2.6.

A. Schedule D-2.6 adjusts base period gas distribution expenses to the amount included in the forecasted test period. The effect of the adjustment on gas operations is an increase in pre-tax operating expenses of $316,688.

Q. PLEASE DESCRIBE SCHEDULE D-2.7.

A. Schedule D-2.7 adjusts base period customer accounts expenses to the amount included in the forecasted test period. The effect of the adjustment on gas operations is an increase in pre-tax operating expenses of $306,001.

Q. PLEASE DESCRIBE SCHEDULE D-2.8.

A. Schedule D-2.8 adjusts base period customer service and information expenses to the amount included in the forecasted test period. The effect of the adjustment on gas operations is a decrease in pre-tax operating expenses of $10,122.

Q. PLEASE DESCRIBE SCHEDULE D-2.9.

A. Schedule D-2.9 adjusts base period sales expense to the amount included in the forecasted test period. Since the Company has no sales expense in either the base or forecasted test period, no adjustment is necessary.

Q. PLEASE DESCRIBE SCHEDULE D-2.10.

A. Schedule D-2.10 adjusts base period administrative and general expenses to the amount included in the forecasted test period. The effect of the adjustment on gas operations is a decrease in pre-tax operating expenses of $652,755.

Q. PLEASE DESCRIBE SCHEDULE D-2.11.

A. Schedule D-2.11 adjusts base period other operating expenses to the amount included in the forecasted test period. The effect of the adjustment on gas operations is an increase in pre-tax operating expenses of $362,672.

Q. PLEASE DESCRIBE SCHEDULE D-2.12.

A. Schedule D-2.12 adjusts base period depreciation expense to the amount included in the forecasted test period. The effect of the adjustment on gas operations is an increase in pre-tax operating expenses of $757,715.

Q. PLEASE DESCRIBE SCHEDULE D-2.13.

A. Schedule D-2.13 adjusts base period taxes other than income taxes to the amount included in the forecasted test period. The effect of the adjustment on gas operations is an increase in pre-tax operating expenses of $2,761,119.

Q. PLEASE DESCRIBE SCHEDULE D-2.14.

A. Schedule D-2.14 adjusts base period income tax expense to the amount included in the forecasted test period. The effect of the adjustment on gas operations is an increase in income tax expense of $266,572.

Q. PLEASE DESCRIBE SCHEDULE D-2.15.

A. The Company sells all of its accounts receivable to an affiliate, Cinergy Receivables, L.L.C. (Cinergy Receivables) at a discount. The discount is based on a formula that compensates the purchasing company for the time value of money and a discount rate based on Duke Energy Kentucky's charge-off (*i.e.*, bad debt) history.

Since the Company's capitalization includes the average balance of receivables at the interest rate being paid to Cinergy Receivables, Schedule D-2.15 ensures that there is no double recovery of the interest expense associated with the uncollectible expense. Consequently, the time value of money component of the discount rate being charged to uncollectible expense (Account 904) is eliminated from the forecasted test year expenses. This portion of the adjustment reduces expenses by $1,025,219. The remaining portion of the adjustment annualizes uncollectible expense based on the revenue included on Schedule C-2 and the Company's proposal to move the portion of net charge offs associated with gas cost revenue to its Rider GCA. This additional adjustment results in a further decrease in pre-tax operating expense of $255,116. I will discuss the Company's proposal for recovery of net charge offs associated with gas cost revenue later in my testimony.

Q. PLEASE DESCRIBE SCHEDULE D-2.16.

A. The adjustment on Schedule D-2.16 is to amortize the projected cost of presenting the instant case. Duke Energy Kentucky proposes to amortize its projected rate case expense over three years, which increases amortization expenses includable in the revenue requirement by $86,667.

Q. PLEASE DESCRIBE SCHEDULE D-2.17.

A. Schedule D-2.17 is not being used in this rate case.

Q. PLEASE DESCRIBE SCHEDULE D-2.18.

A. Interest synchronization is a method used to ensure that the revenue requirements reflect the appropriate income tax effects for jurisdictional interest expense determined by the average cost of debt. Schedule D-2.18 presents the calculation of the state and federal income taxes on the interest cost adjustment included in the cost of capital. The gas jurisdictional capitalization as determined on WPA-1c is multiplied by the long-term and short-term debt percentage of total capitalization as developed on page 2 of Schedule J-1. An adjustment is made to eliminate the applicable portion of Construction Work in Progress (CWIP) subject to Allowance for Funds Used During Construction (AFUDC) from the components of capitalization.

The results are then multiplied by the annual cost of long-term and short-term debt, respectively. The sum of these results represents the annualized gas interest expense deductible for income tax purposes. From this annualized total, we subtract the forecasted test period gas book interest expense that was calculated on WPB-2.18b using the method described by the Commission's ratemaking guidance in Case No. 2001-00092. The effect of this adjustment on gas operations is to decrease state income taxes by $12,700 and to decrease federal income taxes by $69,636.

Q. PLEASE DESCRIBE SCHEDULE D-2.19.

A. Schedule D-2.19 reflects the elimination of revenues and expenses applicable to gas operations devoted to other than Kentucky customers; namely, 65% of the propane storage cavern and related mixing facilities, a portion of the odorization stations, and various feeder lines.

The effect of this elimination is to reduce other revenue by $514,092, O&M expenses by $272,425, payroll taxes by $4,440, and property tax expense by $67,616. The amount of the depreciation expense applicable to these facilities is eliminated on Schedule D-2.23.

Q. PLEASE DESCRIBE SCHEDULE D-2.20.

A. Schedule D-2.20 is an adjustment to reflect the annualization of AFUDC on the CWIP balance as of the plant valuation date. This adjustment is calculated by multiplying CWIP subject to AFUDC, as shown on Schedule B-4, page 2, by the rate of return as shown on Schedule J-1, page 2. The Company is following Commission precedent by using the overall rate of return for this calculation. An adjustment of $289,745 was made to net operating income after tax, based on the Company's use of the overall rate of return for this adjustment.

Q. PLEASE DESCRIBE SCHEDULE D-2.21.

A. Schedule D-2.21 is an adjustment to annualize the property tax expense on the jurisdictional gas plant included in the forecasted test period rate base. The annualized property tax was calculated by segregating the 13-month average jurisdictional gas net plant into four categories: non-taxable property, real estate, tangible personal property, and manufacturing property. Each of these property tax classes was multiplied by their respective estimated property tax ratio. These property tax ratios were arrived at by averaging the ratios approved by the Kentucky Department of Revenue for the past three years. The resulting valuations were multiplied by the estimated property tax rate by class to determine the annualized property tax. The estimated property tax rate was also calculated by averaging the total state and local property tax rate by class for the past three years. The sum of the annualized property tax by class shown on WPD-2.21a is the total annualized property tax expense included in this adjustment. By comparing this result to the amount included in the forecasted test period, an adjustment was made to reduce forecasted test period property tax expense by $894,566.

Q. PLEASE DESCRIBE SCHEDULE D-2.22.

A. Schedule D-2.22 is an adjustment to eliminate miscellaneous expenses such as advertising, sponsorships, and employee recognition expenses from the forecasted test period. These adjustments were made in order to comply with the Commission's orders in prior rate proceedings. The effect of the adjustment on gas operations is a decrease in pre-tax operating expenses of $4,211.

Q. PLEASE DESCRIBE SCHEDULE D-2.23.

A. Schedule D-2.23 is an adjustment to annualize depreciation expense for the forecasted test period. Depreciation expense projected for the test period using the accrual rates proposed by Duke Energy Kentucky witness Mr. John J. Spanos and reflected in Schedule B-3.2 is compared to the depreciation expense included in the forecasted test period, Schedule C-2.1. This adjustment increases depreciation expense by $2,061,951. Since this adjustment impacts the book/tax depreciation timing difference, it also decreases state deferred income taxes by $123,717 and federal deferred income taxes by $678,382.

Q. PLEASE DESCRIBE SCHEDULE D-2.24.

A. Schedule D-2.24 is an adjustment to eliminate $795,537 of unbilled revenue and $846,223 of unbilled gas costs from the forecasted test period. Since the unbilled gas cost is a book/tax timing difference, the adjustment also increases state deferred income taxes by $50,773 and federal deferred income taxes by $278,408.

Q. PLEASE DESCRIBE SCHEDULE D-2.25.

A. Schedule D-2.25 is not being used in this rate case.

Q. PLEASE DESCRIBE SCHEDULE D-2.26.

A. Schedule D-2.26 is an adjustment to reflect a sharing of incentive compensation costs between customers and shareholders. The adjustment utilizes a methodology similar to the one adopted by the Commission in Case Nos. 2005-00042 and 2006-00172. Duke Energy Kentucky witness Mr. Jay R. Alvaro describes the incentive compensation plans and the sharing percentages that the Company proposes to use in its adjustment. The adjustment decreases incentive compensation expense in the forecasted test period by $616,501.

Q. PLEASE DESCRIBE SCHEDULE D-2.27.

A. Schedule D-2.27 is an adjustment to annualize the Kentucky Public Service Commission maintenance tax based on annualized revenue determined on Schedule C-2 and to reflect the most currently available assessment rate. The adjustment decreases expense in the forecasted test period by $48,067.

Q. PLEASE DESCRIBE SCHEDULE D-2.28.

A. In its November 29, 2005, Order in Case No. 2005-00228, approving the Duke Energy/Cinergy merger, the Commission approved a plan to allow the Company to share the anticipated savings that were expected to result from the merger with customers and to amortize deferred merger costs over a five-year period. Schedule D-2.28 is an adjustment to eliminate merger credits and the amortization of merger costs from the forecasted test period. The terms of the merger agreement state that *"upon the effective date of new rates in ULH&P's next gas and electric base rate cases (not including any electric or gas base rate case which results in rates effective prior to January 1, 2008), the gas or electric, rate credit applicable to that service will expire."* To comply with the terms of the merger agreement, the merger credit revenue included in the forecasted test period must be eliminated. Schedule D-2.28 accomplishes this by increasing revenues in the amount of merger credits projected for the forecasted test year, $172,353.

The Order in Case No. 2005-00228 also states *"[i]f ULH&P files a new gas or electric rate case within five years following merger closing, the Company's amortization of such costs for that particular service shall cease upon effective date for such new rates, and ULH&P will not seek to recover such unamortized costs as part of such new base rates."* To comply with the terms of the merger agreement, the amortization of merger costs included in the forecasted test period must be eliminated. Schedule D-2.28 accomplishes this by eliminating amortization of merger costs in the amount of $290,184 from the forecasted test period. The net effect of this adjustment is an increase in pre- tax operating income of $462,537.

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 and the forecasted test period under current rates and for the forecasted test period at proposed rates.

Q. PLEASE DESCRIBE SCHEDULE E-2.

A. Schedule E-2 is for the development of jurisdictional federal and state taxable income and federal and state income tax expense under current rates. Since the utility taxes are 100% jurisdictional, this schedule is not applicable.

Q. PLEASE DESCRIBE SCHEDULE F-1.

A. Schedule F-1, entitled "Social and Service Club Dues," indicates that no social or service club dues were charged to gas operating expenses during the forecasted test period.

Q. PLEASE DESCRIBE SCHEDULE F-2.1.

A. Schedule F-2.1, entitled "Charitable Contributions," lists the charitable contributions made by the Company. As indicated on the schedule, the charitable contributions were included below the line expense and there were no charitable contributions charged to gas operating expenses during the forecasted test period.

Q. PLEASE DESCRIBE SCHEDULE F-2.2.

A. Schedule F-2.2, entitled "Initiation Fees/Country Club Expense," lists the country club expenses incurred by the Company. No country club expenses were charged to gas operating expenses during the forecasted test period and, thus, there are no related jurisdictional costs in the forecasted test period.

Q. PLEASE DESCRIBE SCHEDULE F-2.3.

A. Schedule F-2.3, entitled "Employee Party, Outing, & Gift Expense," indicates that there were no employee party, outing, or gift expenses projected to be included for Duke Energy Kentucky's gas operations during the forecasted test period.

Q. PLEASE DESCRIBE SCHEDULE F-3.

A. Schedule F-3 sets forth the detail, by account, of Customer Service and Informational Sales and General Advertising Expense for both the base and forecasted test periods. A portion of Miscellaneous Customer Service and Informational expense has been eliminated through an adjustment on Schedule D-2.22, in order to comply with the Commission's Orders in prior rate proceedings.

Q. PLEASE DESCRIBE SCHEDULE F-4.

A. Schedule F-4, entitled "Advertising," indicates the advertising expenses projected for gas operations during the forecasted test period.

Q. PLEASE DESCRIBE SCHEDULE F-5.

A. Schedule F-5, entitled "Professional Services Expenses," indicates the professional services expenses projected for gas operations during the forecasted test period.

Q. PLEASE DESCRIBE SCHEDULE F-6.

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

Q. PLEASE DESCRIBE SCHEDULE F-7.

A. Schedule F-7, entitled "Civic, Political and Related Expense," indicates that there are no civic, political and related expenses projected to gas operations during the forecasted test period.

Q. PLEASE DESCRIBE SCHEDULE G-1.

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

Q. PLEASE DESCRIBE SCHEDULE G-2.

A. Schedule G-2 is a Total Company payroll analysis for the most recent five years, the base period and the forecasted test period. Pages 1 and 2 summarize total company costs. Pages 3 through 8 show the total company payroll by employee classification including union, exempt, and non-exempt. Labor hours, labor dollars, employee benefits, payroll taxes, and the number of employees presented on Schedule G-2 represent Duke Energy Kentucky's direct amounts. All numbers presented on Schedule G-2 represent employees of Duke Energy Kentucky only. No charges allocated from Duke Energy Business Services, LLC, are included.

Q. PLEASE DESCRIBE SCHEDULE G-3.

A. Schedule G-3 details total executive compensation and related benefits and taxes, of each of the highest paid executives listed in Duke Energy's 2008 Proxy Statement.

Q. PLEASE DESCRIBE SCHEDULE H.

A. Schedule H, entitled "Computation of Gross Revenue Conversion Factor" (GRCF), sets forth the calculation of the GRCF. This is the factor, or multiplier, used to gross-up the operating income deficiency to a revenue deficiency amount. It includes an uncollectible accounts factor that which represents the portion of the average total discount rate that is related to net charge-offs, collection costs and late payment charges. Also included in the GRCF are the Kentucky Public Service Commission maintenance tax, and state and federal income taxes. The GRCF is included on Schedule A and is used to compute the revenue deficiency.

Q. PLEASE DESCRIBE SCHEDULE K.

A. Schedule K contains certain financial and statistical information for Duke Energy Kentucky, as required pursuant to Kentucky Administrative Regulations. Ms. Melendez sponsors the plant data and the composite depreciation rates contained on page 1. Company witness Mr. Stephen G. De May sponsors the fixed charge coverage ratios, the stock and bond ratings and the percentage of construction expenditures financed internally on page 3. I sponsor the remaining financial and statistical information.

Q. PLEASE DESCRIBE FR 10(8)(a).

A. FR 10(8)(a) contains the financial data for the forecasted test period in the form of *pro forma* adjustments to the base period.

Q. PLEASE DESCRIBE FR 10(8)(b).

A. FR 10(8)(b) contains the forecasted adjustments for the twelve months immediately following the suspension period.

Q. PLEASE DESCRIBE FR 10(8)(c).

A. FR 10(8)(c) contains the 13-month average capitalization and net investment rate base for the forecasted test period ending January 31, 2011.

Q. PLEASE DESCRIBE FR 10(8)(f).

A. FR 10(8)(f) contains a reconciliation of the rate base and capital used to determine the revenue requirements.

Q. PLEASE DESCRIBE FR 10(9)(t).

A. FR 10(9)(t) is a list of all commercially available or in-house developed computer software, programs, and models used in the development of the schedules and workpapers associated with the filing of the Duke Energy Kentucky's application.

IV. <u>INCOME TAX EXPENSE</u>

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 35% for both the base period and forecasted test period.

Q. WHAT TAX RATE DID THE COMPANY USE TO CALCULATE ITS TEST PERIOD STATE INCOME TAX EXPENSE?

A. The Company used the statutory Kentucky corporate income tax rate of 6% for both the base period and forecasted test 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 both the base and forecasted test periods, is 38.90%. This rate includes the corporate statutory federal income tax rate of 35% and the statutory Kentucky corporate income tax rate of 6%. The calculation of the composite federal and state statutory income tax rate is shown on Attachment RMP-1. State income taxes are deductible in computing the federal tax liability and this deduction is considered in computing the overall effective tax liability.

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. It is customary and appropriate to use the income tax rate that most accurately reflects the actual state income tax for a business on a 'stand-alone basis,' which for the base and forecasted test periods is the statutory rate of 6%.

Q. WHAT TAX INFORMATION DID YOU PROVIDE TO OTHER WITNESSES?

A. I provided Company witness Stephen R. Lee 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 September 30, 2009, and the forecasted test period.

I reviewed Mr. Lee's calculation of deferred income taxes for the base period and the forecasted test 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 Mr. De May with the accumulated deferred investment tax credit balance for his use on Schedules J-1, J-1.1 and J-1.2.

V. UNCOLLECTIBLE GAS COST RECOVERY

Q. PLEASE DESCRIBE HOW THE COMPANY IS PROPOSING TO TREAT UNCOLLECTIBLE GAS COST EXPENSE IN THIS PROCEEDING.

A. Duke Energy Kentucky's forecasted test year includes $338,344 of uncollectible expense. Since a customer's bill is essentially made up of two basic types of charges, the fixed costs of providing natural gas delivery service and the variable cost of the natural gas commodity, it logically follows that uncollectible expense should be split between the base and commodity components. In this proceeding, Duke Energy Kentucky is proposing to carve out, or decouple, the uncollectible expense related to the commodity portion of the customer bill and recover the actual net charge offs, which is calculated as actual net charge offs and collection fees less late payment charges of the gas cost billed to customers through the Company's Rider GCA. The portion of uncollectible expense related to the fixed costs associated with delivering natural gas to the customer, $122,920, will remain in base rates. This proposed treatment reduces the amount of uncollectible expense included in base rates and ensures that the Company is only recovering its actual uncollectible expense related to the natural gas delivered. Since the price of natural gas is volatile and the level of consumption of natural gas is declining, at least in part due to price and improved efficiency, including 100% of the uncollectible expense as a fixed charge in base rates results in the Company either over- or under-recovering its uncollectible expense. The Company's proposed adjustment is reflected on WPD-2.15a. If the Commission does not approve this treatment of uncollectible expense, then the amount of uncollectible expense included in base rates will need to be adjusted accordingly to fully reflect uncollectible expense on both the base component of sales and the natural gas commodity component. Mr. Wathen provides further support for this proposed change.

Q. PLEASE EXPLAIN HOW THE COMPANY PROPOSES TO RECOVER THE NET CHARGE OFFS RELATED TO GAS COST BILLED TO CUSTOMERS THROUGH RIDER GCA.

A. When the Company prepares its monthly Rider GCA filing, the uncollectible expense related to commodity gas costs will be included in the calculation of the Expected Gas Cost (EGC) on Schedule I. The uncollectible expense related to gas costs will be calculated as shown on Attachment RMP-3. The uncollectible expense for the most recent month actual data is available at the time of the filing will be split between base revenue and gas cost revenue based on their respective ratio of that month's total gas revenue. The gas cost portion of the net charge offs will be included in the EGC for recovery in the following month as shown on Attachment RMP-4.

Q. IS THERE ANY PROVISION FOR TRUE UP OF ANY OVER- OR UNDER-RECOVERY OF THE NET CHARGE OFFS?

A. Yes. The normal operation of the Actual Adjustment through Rider GCA calls for a quarterly true up of the EGC through the Actual Adjustment included on Schedule III of the Rider GCA filing. The Actual Adjustment is included in Rider GCA for the following twelve months. Any residual amount to be trued up after the twelve months of recovery is transferred to the Balance Adjustment for final disposition over the following twelve month period.

VI. CARRYING COSTS ON GAS STORED UNDERGROUND

Q. WHAT IS THE COMPANY'S PROPOSAL FOR EARNING CARRYING COSTS ON GAS STORED UNDERGROUND?

A. The Company has removed Gas Stored Underground from its calculation of Working Capital on Schedule B-5.1 and is proposing to recover the carrying costs on this item through Rider GCA. Mr. Wathen explains in his testimony the reasons the Company is proposing this method of recovery.

Q. PLEASE EXPLAIN HOW THIS RECOVERY WOULD BE ACCOMPLISHED.

A. Each month, the Company files an update to Rider GCA for the Expected Gas Cost to be billed the following month. The carrying costs on the estimated average balance of Gas Stored Underground for the revenue month will be included in the calculation of Rider GCA. Attachment RMP-2 provides a sample of this calculation. In this example, January 2010's actual balance is known. The February and March balances are estimated based on expected injections and/or withdraws. Carrying costs are calculated on the average of the February and March ending balances. This carrying cost amount is included in Schedule I of the March Rider GCA filing and shown on Attachment RMP-4.

Q. WHAT RATE WOULD BE USED TO CALCULATE THE AMOUNT OF CARRYING COSTS TO BE INCLUDED IN RIDER GCA?

A. The Company will use the rate of return approved by the Commission in this case on a pre-tax basis. Page 3 of Attachment RMP-2 provides the calculation of the pre-tax rate of return based on the return requested by the Company in this case.

Q. IS THERE A PROVISION FOR TRUE UP OF ANY OVER- OR UNDER-RECOVERY OF THE CARRYING COST AMOUNT?

A. Yes. Just as the EGC is trued up through the Actual Adjustment, the carrying costs will be adjusted to actual and any over- or under-recovery will be included in the Actual Adjustment. The Actual Adjustment is billed for the following twelve months and any residual amount is then transferred to the Balance Adjustment for future recovery or refund.

VII. <u>CONCLUSION</u>

Q. WERE SCHEDULES A, B-1, B-5, B-5.1, B-6, C-1 THROUGH C-2.2, D-1, D-2.1 THROUGH D-2.28, E-1, E-2, F-1 THROUGH F-7, G-1 THROUGH G-3, H, AND K, FR10(8)(A), FR10(8)(B), FR10(8)(C), FR10(8)(F) AND FR10(9)(T), THE TAX INFORMATION YOU SUPPLIED TO OTHER WITNESSES AND ATTACHMENTS RMP-1, RMP-2, RMP-3 AND RMP-4

PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

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

A. Yes

VERIFICATION

State of Ohio)
) SS:
County of Hamilton)

The undersigned, Robert M. Parsons, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robert M. Parsons

Robert M. Parsons, Affiant

Subscribed and sworn to before me by Robert M. Parsons on this 17th day of June 2009.

Patty A. Selm

NOTARY PUBLIC

My Commission Expires

PATTY A. SELM
Notary Public, State of Ohio
My Commission Expires 09-15-2014

280056

DUKE ENERGY KENTUCKY
Calculation of Combined Statutory Income Tax Rate
Base and Forecasted Periods

Line No.			
1	State Taxable Income	$100.00	
2	Statutory State Income Tax Rate	6.00%	
3	State Income Tax		$6.00
4	Federal Taxable Income	$94.00	
5	Statutory Federal Income Tax Rate	35.00%	
6	Federal Income Tax		$32.90
7	Total Income Tax		$38.90
8	Combined Statutory Federal and State		
9	Income Tax Rate (line 7/line1)		38.90%

PURCHASED GAS ADJUSTMENT
COMPANY NAME: DUKE ENERGY KENTUCKY, INC.

SUPPLEMENTAL MONTHLY REPORT

ESTIMATED COST OF GAS INJECTED AND WITHDRAWN FROM STORAGE

Details for the EGC Rate in Effect as of March, 2010

			Monthly Storage Activity			
Line No.	Month	Beginning Storage Inventory	Injected	Withdrawn		Ending Storage Inventory
1	January 2010	$9,709,615	$0	$2,952,467	(a)	$6,757,148
2	February 2010	$6,757,148	$0	$2,008,194	(b)	$4,748,954
3	March 2010	$4,748,954	$0	$2,440,624	(b)	$2,308,330

(a) Actual
(b) Estimated

PURCHASED GAS ADJUSTMENT
COMPANY NAME: DUKE ENERGY KENTUCKY, INC.

SUPPLEMENTAL MONTHLY REPORT

ESTIMATED CONTRACT STORAGE CARRYING COSTS

Details for the EGC Rate in Effect as of March, 2010

Line No.	Ending Storage Balance Month	*Estimated* Ending Storage Inventory	Average Monthly Storage Inventory Balance	Avg. Storage *Balance* times Monthly Cost of Capital (1)	Estimated Monthly MCF	$/MCF
				0.758333%		
1	January 2010	$6,757,148				
2	February 2010	$4,748,954				
3	March 2010	$2,308,330	$3,528,642	$26,759	1,505,786	$0.018

Note (1): 9.10% divided by 12 months = 0.758333%. See Page 3 of 3.

PURCHASED GAS ADJUSTMENT
COMPANY NAME: DUKE ENERGY KENTUCKY, INC.

SUPPLEMENTAL MONTHLY REPORT

CALCULATION OF PRE-TAX RATE OF RETURN

Details for the EGC Rate in Effec March, 2010

Line No.	CLASS OF CAPITAL	13 MONTH AVG BALANCE ($)	% OF TOTAL	% COST	WEIGHTED COST %	GROSS REVENUE CONVERSION FACTOR	PRE-TAX RETURN
1	Common Equity	411,218,278	49 901%	11 000%	5 489%	1 004349	5 513%
2	Long-Term Debt	367.408,791	44 585%	4 657%	2 076%	1 64378	3 412%
3	Short-Term Debt	45,441,090	5 514%	1 917%	0.106%	1 64378	0.174%
4	Total Capital	824,068,159	100.000%		7.671%		9.100%

DUKE ENERGY KENTUCKY
Net Charge Offs, Collection Fees and Late Payment Charge
Split Between Base Cost and Gas Cost

Line No.		Source	Example Month		
1	Net Charge Offs	Gross/Net Write Off Report	$350,000		
2	Electric Allocation (1)	A/R Sale Journal Entry Calculation	$247.555		
3	Gas Allocation (1)	A/R Sale Journal Entry Calculation	$102.445	$102 445	
4	Gas Collection Fees	A/R Sale Journal Entry Calculation		5 700	
5	Gas Late Payment Charge	A/R Sale Journal Entry Calculation		(48,000)	
6	Total Gas Net Charge Offs, Collection Fees and Late Payment Charges			$60,145	
7	*Actual Billed Revenue*				
8	Revenue Less Gas Cost Revenue	Revenues - Billing System	$2,700 000		
9	Gas Cost Revenue	Revenues - Billing System	11,200,000		
10	Total Billed Revenue		$13,900,000		
11	Ratio of Revenue to Total				
12	Revenue Less Gas Cost Revenue	Calculated (Line 3 / Line 5)	19 424%		
13	Gas Cost Revenue	Calculated (Line 4 / Line 5)	80.576%		
14	Total Billed Revenue		100.000%		
15	Net Charge Offs and Expenses				
16	Base Rate	Calculated (Line 6 * Line 12)		$11 683	
17	Gas Cost	Calculated (Line 6 * Line 13)		**$48,462**	**To Rider GCA filing, Schedule I**

(1) Allocated on percent of service revenues to total revenues

GAS COST ADJUSTMENT
DUKE ENERGY KENTUCKY
EXPECTED GAS COST RATE CALCULATION (EGC)

"SUMMARY" FOR THE EGC RATE IN EFFECT AS OF XXXXX 1, 2010

					$	
DEMAND (FIXED) COSTS:						
Columbia Gas Transmission Corp.					2,604,075	
Texas Gas Transmission					490,750	
Tennessee Gas Pipeline					1,059,993	
Columbia Gulf Transmission Corp.					925,578	
KO Transmission Company					307,584	
Gas Marketers					34,019	
TOTAL DEMAND COST:					5,421,999	
PROJECTED GAS SALES LESS SPECIAL CONTRACT IT PURCHASES:			10,233,165	MCF		
DEMAND (FIXED) COMPONENT OF EGC RATE:	$5,421,999	/	10,233,165	MCF	**$0.530**	**/MCF**
COMMODITY COSTS:						
Gas Marketers					$5.553	/MCF
Gas Storage						
Columbia Gas Transmission					$0.000	/MCF
Propane					$0.000	/MCF
COMMODITY COMPONENT OF EGC RATE:					**$5.553**	**/MCF**
OTHER COSTS:						
Storage Carrying Costs	$26,759	/	1,505,786	MCF	**$0.018**	/MCF
Net Charge Off	$48,462	/	1,505,786	MCF	**$0.032**	/MCF
OTHER COST COMPONENT OF EGC RATE:					**$0.050**	**/MCF**
TOTAL EXPECTED GAS COST:					**$6.133**	**/MCF**

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN ADJUSTMENT	)	
OF GAS RATES OF	)	CASE NO. 2009-00202
DUKE ENERGY KENTUCKY, INC.	)	

DIRECT TESTIMONY OF

TIMOTHY A. PHILLIPS

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

July 1, 2009

269101

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Timothy A. Phillips. 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, an affiliate service company of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company), as Lead Forecaster, Forecasting Department.

Q. PLEASE SUMMARIZE YOUR EDUCATION.

A. I received a Bachelor of Science degree in Business, majoring in Finance, from Indiana University in 1992 and a Master of Arts degree in Economics from Indiana University in 1995. I also completed an additional year of graduate study towards a doctorate in Economics at the University of Iowa in 1998.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. I was a Research Assistant in the Department of Economics at both Indiana University - Purdue University at Indianapolis (IUPUI) and The University of Iowa (TUOI). Most of this research involved the analysis and modeling of health and financial data using various econometric techniques.

I also taught *Principles of Microeconomics* at IUPUI during 1996-1997 and was a Teaching Assistant for *Principles of Macroeconomics* and *Statistical Analysis* at TUOI.

I joined Cinergy Corp. in January 1999 as a Marketing Analyst in the Load Forecasting Department. I was promoted to Senior Analyst in February

2004. In January 2008, after the merger between Cinergy Corp. and Duke Energy (Duke Energy), I was promoted to my current position of Lead Forecaster.

Q. PLEASE DESCRIBE YOUR DUTIES AS LEAD FORECASTER.

A. My primary responsibility is to assist in the development and maintenance of Duke Energy's long-term electric and gas forecasts for its three-state Midwest service area. 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 complete various data requests and special projects, both internal and external to my department, requiring statistical, forecasting, and/or economic analysis.

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

A. No, I have not.

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

A. My testimony explains the Company's methodology used to prepare the gas forecast. I discuss the normal weather conditions used in the preparation of the gas forecast. I also sponsor certain information that I provided to Duke Energy Kentucky witness Mr. Stephen R. Lee for his use in calculating the forecasted test period data.

II. DEVELOPMENT OF THE FORECAST

Q. WHAT INFORMATION DID YOU PROVIDE TO MR. LEE FOR HIS USE IN CALCULATING THE FORECASTED TEST PERIOD DATA?

A. I provided Mr. Lee with a forecast of the projected gas and electric sales for Duke Energy Kentucky on a monthly basis for each customer class over a ten-year period. These forecasts are updated at least annually. I also provided Mr. Lee with the projected number of customers for each customer class.

Q. DID YOU PREPARE DUKE ENERGY KENTUCKY'S CURRENT GAS FORECAST?

A. Yes.

Q. HOW DID YOU DEVELOP THE FORECAST?

A. Generally speaking, I developed the forecast in three steps. First, I obtained a service area economic forecast. Next, I prepared an energy forecast. Finally, using the energy forecast, I prepared a winter peak forecast.

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

A. I obtained the economic forecast of the service area from Economy.com, a nationally recognized economic forecasting firm. Based upon its forecast of the national economy, Economy.com prepares a forecast of key economic concepts specifically for the service area of 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 models.

Q. HOW DID YOU DEVELOP THE ENERGY FORECAST?

A. The energy forecast projects the energy required to serve retail customer classes - residential, commercial, industrial and governmental. I determined the projected energy requirements for Duke Energy Kentucky's retail gas customers through econometric analysis. Econometric models are a means of representing economic behavior through statistical methods such as regression analysis.

Q. PLEASE EXPLAIN HOW YOU DEVELOPED THE PEAK FORECAST.

A. I developed the forecast of winter peak demand by also using an econometric model. This econometric model examines the historical relationship between peak demand, weather, and total system deliveries. System deliveries are used to capture the effect of changes in economic growth and space heat saturation.

Q. WHAT ARE THE PRIMARY FACTORS AFFECTING ENERGY USAGE?

A. Some of the major factors are the number of customers (for residential class only) and economic variables such as employment, industrial production, income and price. Employment and income variables measure economic activity levels. Generally, energy use increases with higher industrial and commercial economic activity as well as with increased saturation of residential appliances, including space heating equipment. As prices increase, energy usage tends to decrease due to customers' energy conservation activities. In addition, weather is an important factor affecting energy usage.

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

A. Yes. Variables are included in the equations to account for these factors. By including these variables, it is then possible to project the future energy consumption based on forecasts of these factors.

Q. HOW DOES MANAGEMENT JUDGMENT FIT INTO THE FORECASTS?

A. Under any approach to 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 that affect usage.

Q. WHAT GROWTH DOES THE GAS FORECAST PROJECT?

A. The forecast projects an annual growth of 0.10% in gas deliveries over the next five years, 2010-2015. Attachment TAP-1 shows the gas sales forecast and five-year growth rates for residential, commercial, industrial, governmental, other, and deliveries for 2010 through 2015.

III. WEATHER

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

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

Q. WHAT IS A HDD?

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

Heating Degree Days = Base Temperature – Daily Average Temperature

Q. PLEASE EXPLAIN "NORMAL" WEATHER.

A. The gas forecast projects Duke Energy Kentucky's gas sales for the test period. In order to project this, I must make a judgment about the weather conditions expected to occur during the test period. These expected weather conditions are known as "normal" weather. Importantly, the "normal" weather must be representative of current weather trends since it is used to predict the level of weather expected to occur in the future. I then prepare Duke Energy Kentucky's gas forecast based on such expected weather conditions.

Q. ARE MEASURES OF NORMAL WEATHER AVAILABLE?

A. Yes. One such source is the National Oceanic and Atmospheric Administration (NOAA) of the U.S. Department of Commerce, which publishes measures of normal degree days. Additional information about NOAA is available at www.noaa.gov.

Q. DOES 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. NOAA updates its calculations for the United States for thirty-year periods at the end of each decade. The most current thirty-year period used by NOAA is 1971-2000. NOAA's next thirty-year normal weather period will be 1981-2010.

NOAA provides estimates of "normal" HDD using daily measurements obtained from the weather station located at the Northern Kentucky and Greater Cincinnati International Airport. This data is provided on a daily, monthly and annual basis. Attachment TAP-2 provides the NOAA thirty-year degree day normals for Covington, Kentucky, for the period from 1961 through 1990 and the most recent NOAA thirty-year degree day normals for Covington, Kentucky, for the period from 1971 through 2000.

Q. WHAT ARE THE NOAA ANNUAL NORMAL HDD FOR COVINGTON, KENTUCKY FOR 1960 THROUGH 1990 AND FOR 1971 THROUGH 2000?

A. The annual level of normal HDD for the years 1961 through 1990 is 5,248. The annual level of normal HDD for the years 1971 through 2000 is 5,148.

Q. HAS NOAA'S DATA FOR THE THIRTY-YEAR NORMAL WEATHER BEEN THE SUBJECT OF RECENT EVALUATION OR REVIEW?

A. Yes. NOAA has recognized that the standard thirty-year normal is not meeting the needs of industry, utilities and other users of its data. Via a letter dated September 17, 2007, A nthony Arguez, Ph.D., Research Climatologist for the National Climatic Data Center initiated discussions to solicit input from the users of NOAA's normal weather. Dr. Arguez's letter is provided in Attachment TAP-3 and excerpted below:

> Climate normals are very important factors in commercial, industrial, agricultural, building, and transportation planning. The energy industry, in particular, is uniquely sensitive to climatic factors, including normals.
>
> Producing climate normals that are more representative of the current state of the climate, at the time they are computed, is a major goal of our efforts.
>
> There is also a need to create climate normals that take into account a changing climate. Climate normals were designed for climates that were thought to be relatively stationary, *i.e.*, climates in which long-term averages do not vary a great deal in time. According to the Fourth Assessment Report of the

> Intergovernmental Panel of Climate Change (IPCC), however, there is virtually universal consensus that the climate has warmed relatively rapidly over the last 30 years.
>
> ...we look forward to continuing to work closely with all segments of the energy/utility industry to strategize on ways to provide better climate normals...

Duke Energy is participating in these discussions with NOAA, with such participation including a webcast on June 2, 2009.

IV. TEN-YEAR WEATHER NORMALS

Q. DID YOU USE THIRTY-YEAR WEATHER NORMALS TO PREPARE DUKE ENERGY KENTUCKY'S GAS FORECAST?

A. No. I initially consulted the normal weather data prepared by NOAA, particularly, the thirty-year weather normals, and compared them to more recent NOAA weather data. I ultimately determined that it would be more appropriate to use NOAA weather data for a recent ten-year period to prepare the gas forecast.

Q. WHY DID YOU USE TEN-YEAR WEATHER NORMALS INSTEAD OF THIRTY-YEAR WEATHER NORMALS FOR THE FORECAST?

A. Importantly, the "normal" weather used in the forecast must be representative of current weather trends. Experience during the past several years indicates that the NOAA normals based on 1971 through 2000 are not representative of current weather for the Duke Energy Kentucky service area. There is evidence of a long-term downward trend in HDD. Also, during the past several years, HDD were well below the thirty-year HDD levels. Therefore, I concluded that the thirty-year normals were no longer representative as an estimate of the weather used to produce the forecast. In my opinion, it is reasonable to forecast Duke Energy

Kentucky's gas sales for the test period using normals derived from the actual weather experienced over a recent ten-year period.

Q. WHAT HAS BEEN THE LONG-TERM TREND IN DEGREE-DAYS?

A. For the years 1971 through 2008, HDD have experienced a downward trend. The graph shown in Attachment TAP-4 provides visual evidence of this trend. This same trend is also evidenced by the fact that the NOAA heating degree day normals based on the thirty-year period from 1971 through 2000 are lower than the normals based on the period of 1961 through 1990 (5,148 vs. 5,248).

In developing a forecast, the objective is to use a level of normal degree days that provides an unbiased estimate of the expected weather conditions. Therefore, I concluded that it would be reasonable to use normal HDD derived from the actual weather experienced over a recent ten-year period to capture the current trend.

Q. WHAT HAS BEEN THE TREND IN HDD FOR COVINGTON, KENTUCKY, SINCE 1998?

A. For the years 1999 through 2008, the trend in HDD for Covington, Kentucky, has continued downward, as can be seen from the graph in Attachment TAP-5.

Q. HOW DO THE ACTUAL ANNUAL HDD FOR THE LAST TEN YEARS FOR COVINGTON, KENTUCKY COMPARE TO THIRTY-YEAR NORMALS?

A. For the period of 1999 through 2008, Duke Energy Kentucky experienced seven out of ten years where actual annual HDD were below the thirty-year normal HDD level of 5,148. See Attachments TAP-5 and TAP-6. This illustrates that, over most of the last ten years, and especially the last five years, the NOAA HDD normal is too high.

Q. HOW DO THE ACTUAL ANNUAL HDD FOR THE LAST TEN YEARS COMPARE TO THE TEN-YEAR NORMALS?

A. For the period 1999 through 2008, Duke Energy Kentucky experienced five out of the ten years where actual annual HDD were below the ten-year normal of 4,881 and five out of ten years where actual annual HDD were above the ten-year normal of 4,881, which is an even distribution around the normal. See Attachment TAP-6.

Q. CAN THE DUKE ENERGY KENTUCKY NORMAL WEATHER AND NOAA NORMAL WEATHER BE COMPARED USING MEAN PERCENT ERROR (MPE)?

A. Yes. MPE can indicate whether the measure of normal degree days contains any bias to over-estimate or under-estimate the actual weather conditions. For example, if MPE is positive, this indicates that there is a bias for the measure of normal to be higher than the actual. If MPE is close to zero, this indicates that there is no bias for the measure of normal to be different 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

The MPE for HDD calculated for the years 1999 through 2008 comparing actual degree days to the ten-year average HDD used as normal results in an MPE of 0.2%. See Attachment TAP-6. This measure is close to zero. These results indicate that the ten-year estimate of normal degree days is a reasonable predictor of HDD.

The MPE for HDD calculated for the years 1999 through 2008, comparing actual degree days to the thirty-year NOAA normal for the forecast, results in an MPE of 5.7%. See Attachment TAP-6. This measure indicates that the NOAA normal weather has a strong bias to be higher than the actual. Also, this measure is further from zero than the MPE calculated using the Duke Energy Kentucky normal weather. It is apparent that the Duke Energy Kentucky measures of normal weather more closely predicted actual HDD.

Q. WHAT CAN YOU REASON FROM THESE RESULTS?

A. Given the evidence of a downward trend in HDD, along with the fact that for the majority of recent years HDD were below the NOAA normal, I concluded that the NOAA HDD normals were not representative. Therefore, the normals based on weather from 1999 through 2008 are, in my opinion, more accurate representations of normal weather.

Q. DID YOU BASE YOUR DECISION TO USE TEN-YEAR WEATHER NORMALS ON ANY OTHER INFORMATION?

A. Yes. One compelling support for ten-year weather normals comes from the U.S. Department of Energy, Energy Information Administration (EIA). Just recently, this agency changed to a ten-year normal for use in its national and regional energy forecast in the Annual Energy Outlook 2008 (AEO2008). Attachment TAP-7 provides the relevant section from the AEO2008 discussing the change to a ten-year normal. John Cymbalsky of the EIA also made a presentation explaining the reasons for the change and relevant excerpts from this presentation are provided in Attachment TAP-8.

Additionally, NOAA has available on their web site a tool called "Dynamic Normals" that allows a person to extract daily or monthly normal degree days for something other than thirty years. The number of years chosen is at the discretion of the user. Thus, NOAA itself is encouraging organizations to use periods other than thirty-year normals where other periods appear to be better predictors of the weather that will be in effect during the time period under consideration.

Finally, in June 2007, William Gresham of Columbia Gas conducted an informal survey of gas distribution companies regarding their forecasting practices. A copy of the survey and results are provided in Attachment TAP-9. The survey asked the following question about weather:

> "What is the definition for normal weather for your company's financial plan?"

The results of the survey indicate that 17 of the 35 companies (49%) use something other than a thirty-year average and that 10 of the 35 (29%) use a ten-year average.

In the present case, given my own analysis and the supporting reasons above, it would be reasonable to use ten-year weather normals for preparing the gas forecast.

Q. WHAT BASE TEMPERATURE IS USED BY DUKE ENERGY KENTUCKY TO CALCULATE HDD?

A. The base temperature used to calculate HDD is 59 degrees Fahrenheit (59°F).

Q. WHY IS A BASE TEMPERATURE OF 59°F USED TO CALCULATE HDD RATHER THAN 65°F AS USED BY NOAA?

A. Duke Energy Kentucky plotted class level daily gas loads versus daily average temperature. Attachment TAP-10 provides visual evidence that heating loads begin around 59°F. The Company further conducted a statistical analysis of data on the residential class, whose usage is very weather sensitive. We evaluated the R^2 values, regressing gas usage against HDD, using different base temperatures ranging from 65°F through 55°F. Results showed that the R^2 value at 59°F was the largest, indicating the best fit for the data in Duke Energy Kentucky's service area as shown below:

Temp.	R^2
65°F	0.95845
64°F	0.96284
63°F	0.96667
62°F	0.96989
61°F	0.97227
60°F	0.97369
59°F	**0.97425**
58°F	0.97376
57°F	0.97214
56°F	0.96916
55°F	0.96484

Using the visual evidence in the graphs and the R^2 analysis, the Company selected 59°F as the base temperature for HDD. This evidence indicates that heating loads begin at 59°F and that gas usage is flat for temperatures above 59°F.

Q. DO ANY OTHER UTILITY COMPANIES CALCULATE HDD USING A BASE TEMPERATURE OTHER THAN 65°F?

A. Yes. The 2005 Gas Forecasting Benchmark Survey sponsored by the Ohio Gas Association and the American Gas Association indicates that 7 out of 43 respondents (16%) use a base temperature other than 65°F when calculating HDD.

Each utility should use the base temperature for calculating HDD that best indicates when heating load begins. In Duke Energy Kentucky's case, this is a base temperature of 59°F. Historical HDD, calculated with a base of 59°F, were utilized in the estimation and development of the econometric forecasting models.

Q. WHAT ANNUAL LEVEL OF NORMAL HEATING DEGREE DAYS DID YOU USE FOR THE FORECASTS?

A. I used the ten-year weather normal of 3,604 HDD, also based on 59°F, to develop the forecast. In my opinion, this weather normal more accurately represents reasonable weather conditions for gas forecasting.

V. CONCLUSION

Q. IN YOUR OPINION, IS DUKE ENERGY KENTUCKY'S FORECAST REASONABLE?

A. Yes. The forecast is reasonable and the methods used to establish the forecast were reasonable and appropriate.

Q. DID YOU EITHER PREPARE OR REVIEW AND RELY UPON ATTACHMENTS TAP-1 THROUGH TAP-10 IN DEVELOPING YOUR TESTIMONY?

A. Yes.

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

A. Yes.

VERIFICATION

State of Ohio)
)
County of Hamilton)

The undersigned, Timothy A. Phillips, being duly sworn, deposes and says that he is a Lead Forecaster, Forecasting Department, at Duke Energy Business Services, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Timothy A. Phillips, Affiant

Subscribed and sworn to before me by Timothy A. Phillips on this 16TH day of June, 2009.

ADELE M. DOCKERY
Notary Public, State of Ohio
My Commission Expires 01-05-2014

NOTARY PUBLIC

My Commission Expires: 01/05/2014

Duke Energy Kentucky Billed MCF Gas Sales Forecast

	Residential	Commercial	Industrial	Governmental	Other	Deliveries
2010	6,460,177	3,714,644	1,941,809	887,643	11,905	13,016,178
2011	6,477,120	3,724,156	1,905,911	872,893	11,905	12,991,985
2012	6,511,005	3,725,776	1,873,234	865,330	11,905	12,987,250
2013	6,545,547	3,726,903	1,855,036	867,081	11,905	13,006,472
2014	6,587,180	3,734,085	1,843,177	866,939	11,905	13,043,286
2015	6,624,487	3,737,801	1,841,183	867,367	11,905	13,082,743
Five-year growth	0.50%	0.12%	-1.06%	-0.46%	0.00%	0.10%

NOAA Thirty-Year Normals
For 1961 - 1990

KENTUCKY

HEATING DEGREE DAY NORMALS (BASE 65 F)

STATION	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	ANN
ASHLAND	0	5	72	338	621	949	1101	910	679	382	155	13	5225
BARBOURVILLE	0	0	35	306	546	856	992	792	580	303	123	7	4540
BARDSTOWN	0	0	36	263	534	859	1008	801	558	270	108	0	4437
BARREN RIVER LAKE	0	0	32	251	522	853	1014	809	576	264	105	0	4426
BAXTER	0	0	46	310	573	874	1001	812	611	325	135	6	4693
BEAVER DAM	0	0	32	238	501	837	986	762	525	227	85	0	4193
BEREA COLLEGE	0	0	30	239	495	815	961	759	531	246	98	0	4174
BERNHEIM FOREST	0	0	33	244	513	843	1004	787	545	254	98	0	4321
BOWLING GREEN FAA AP	0	0	37	251	525	843	995	778	551	253	95	0	4328
BRADFORDSVILLE	0	0	49	303	570	890	1054	846	620	319	138	0	4789
CAMPBELLSVILLE 2 SSW	0	0	36	245	507	818	977	762	530	248	100	0	4223
CARROLLTON LOCK 1	0	0	36	267	528	874	1029	820	586	282	115	0	4537
CECILIA 2 SE	0	0	51	308	588	915	1085	868	626	303	128	0	4872
COVINGTON WSO AP	0	0	51	327	621	977	1144	930	682	354	151	11	5248
DANVILLE	0	0	43	285	561	905	1060	860	629	317	141	6	4807
DIX DAM	0	0	29	243	498	831	986	787	565	269	110	0	4318
FALMOUTH	0	11	68	360	642	980	1147	935	713	400	177	10	5443
FARMERS 2 S	0	5	57	329	594	915	1082	885	654	354	145	8	5028
FRANKFORT LOCK 4	0	0	47	310	582	921	1091	890	663	348	145	5	5002
GLASGOW	0	0	32	259	528	837	983	762	532	237	91	0	4261
GOLDEN POND 8 N	0	0	22	230	495	837	989	778	540	232	82	0	4205
GRAYSON 3 SW	0	6	71	359	627	946	1101	913	698	399	181	14	5315
GREENSBURG	0	0	35	275	543	865	1020	818	586	284	122	0	4548
GREENVILLE 2 W	0	0	28	227	492	822	958	742	511	218	87	0	4085
HEIDELBERG LOCK 14	0	0	52	316	585	899	1051	851	632	344	136	0	4866
HENDERSON 7 SSW	0	0	26	226	507	871	1017	798	552	238	88	0	4323
HODGENVILLE-LINCOLN NP	0	0	35	242	513	849	995	778	539	249	99	0	4299
HOPKINSVILLE	0	0	29	250	525	871	1023	809	570	259	101	0	4437
JACKSON WSO AP	0	0	38	264	519	840	998	798	549	262	125	0	4393
LEITCHFIELD 2 N	0	0	43	265	540	871	1017	804	564	270	108	0	4482
LEXINGTON WSO AP	0	0	47	287	570	902	1060	854	611	312	135	5	4783
LONDON FAA AP	0	0	56	302	555	853	1001	790	573	290	129	9	4558
LOUISVILLE WSFO AP	0	0	36	254	537	871	1032	820	580	273	105	6	4514
LOVELACEVILLE	0	0	25	212	501	837	977	759	528	216	77	0	4132
MADISONVILLE	0	0	26	225	498	840	986	770	529	216	77	0	4167
MAMMOTH CAVE PARK	0	0	35	252	510	831	980	762	533	234	97	0	4234
MANCHESTER 4 W	0	0	54	327	576	877	1020	826	620	341	137	5	4783
MAYFIELD RADIO WNGO	0	0	21	202	480	818	949	734	505	215	73	0	3997
MAYSVILLE SEWAGE PLANT	0	6	51	312	600	946	1110	916	688	372	159	10	5170
MIDDLESBORO	0	0	41	305	558	859	989	801	595	319	139	5	4611
MONTICELLO 3 NE	0	0	41	286	546	846	1004	801	586	321	130	0	4561
MOUNT VERNON	0	0	52	305	564	893	1048	840	614	315	125	0	4756
MURRAY	0	0	19	202	468	809	949	722	499	195	69	0	3932
OWENSBORO 3 W	0	0	28	228	519	865	1017	792	552	241	92	0	4334
PADUCAH WSO	0	0	24	228	513	859	1004	787	550	231	83	0	4279
PADUCAH SEWAGE PLANT	0	0	27	235	525	874	1020	815	572	237	88	0	4393
PRINCETON 1 SE	0	0	24	216	483	825	970	753	515	216	74	0	4076
ROCHESTER FERRY	0	0	48	297	555	884	1039	834	598	287	115	0	4657
RUSSELLVILLE	0	0	35	265	519	862	1014	815	561	259	109	0	4439
SCOTTSVILLE 3 SSW	0	0	23	201	462	784	927	708	478	204	86	0	3873
SHELBYVILLE 1 E	0	5	64	346	624	964	1128	918	698	381	159	7	5294
SOMERSET 2 N	0	0	47	285	540	840	983	778	555	279	108	0	4415
STEARNS	0	0	63	326	564	874	1008	826	601	326	155	7	4750
SUMMER SHADE	0	0	35	262	519	828	977	762	539	253	101	0	4276
TOMAHAWK 1 WSW	0	5	83	372	630	946	1091	899	657	357	167	12	5219
WARSAW MARKLAND DAM	0	0	47	331	609	961	1128	924	694	372	160	8	5234
WAYNESBURG 7 NE	0	0	44	282	531	853	998	792	561	282	127	6	4476
WEST LIBERTY	0	0	70	349	618	936	1085	888	663	366	162	9	5146
WILLIAMSBURG	0	0	38	292	534	837	973	790	574	292	121	0	4451
WILLIAMSTOWN 3 NW	0	0	41	270	564	921	1079	868	626	320	140	0	4829

United States Climate Normals 1971-2000

CLIMATOGRAPHY OF THE UNITED STATES NO. 81

Monthly Normals of Temperature, Precipitation, and Heating and Cooling Degree Days
1971-2000

KENTUCKY

No	Station Name	Element	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
			DEGREE DAYS (Total)												
003	ASHLAND	HDD	1076	875	684	383	171	27	1	9	77	338	636	940	5217
		CDD	0	0	0	4	69	185	299	254	113	19	0	0	943
004	BARBOURVILLE	HDD	958	757	578	318	136	10	0	2	42	306	557	846	4510
		CDD	0	0	0	6	85	209	331	295	135	34	1	0	1096
005	BARDSTOWN 5 E	HDD	996	768	566	289	117	7	0	5	49	281	558	861	4497
		CDD	0	0	0	9	96	221	341	301	139	29	0	0	1136
005	BARDWELL 2 E	HDD	959	717	505	222	77	2	0	1	30	213	508	833	4067
		CDD	0	0	3	22	139	313	434	371	183	33	2	0	1500
007	BARREN RIVER LAKE	HDD	961	753	549	272	110	6	0	1	33	239	509	823	4256
		CDD	0	0	1	17	127	278	409	364	185	42	2	0	1425
008	BAXTER	HDD	964	772	601	331	140	12	0	3	50	307	574	850	4604
		CDD	0	0	0	4	75	188	310	277	126	25	0	0	1005
009	BEAVER DAM	HDD	973	735	530	250	94	3	0	1	37	240	520	838	4221
		CDD	0	0	1	15	117	272	393	346	172	32	1	0	1349
010	BEREA COLLEGE	HDD	941	727	540	264	108	8	0	4	46	262	518	813	4231
		CDD	0	0	1	14	106	230	334	292	142	29	2	0	1150
012	BERNHEIM FOREST	HDD	967	741	533	265	100	6	0	2	31	236	515	829	4225
		CDD	0	0	1	14	114	255	383	348	174	35	2	0	1326
019	BOWLING GREEN FAA AP	HDD	956	740	535	261	99	4	0	2	40	251	527	828	4243
		CDD	0	0	1	15	122	283	417	366	178	31	0	0	1413
020	BRADFORDSVILLE	HDD	997	789	605	325	139	8	0	3	50	300	567	865	4648
		CDD	0	0	0	6	92	224	354	306	141	27	1	0	1151
023	CAMPBELLSVILLE 2 SSW	HDD	957	737	537	271	114	8	0	3	42	252	518	810	4249
		CDD	0	0	0	9	107	242	352	310	148	33	1	0	1202
032	CARROLLTON LOCK 1	HDD	999	778	579	290	118	7	0	3	33	251	520	854	4432
		CDD	0	0	0	7	103	236	367	331	170	39	1	0	1254
039	CINCINNATI COVINGTON AP	HDD*	1110	881	670	368	130	19	1	3	68	319	626	953	5148
		CDD*	0	0	3	13	73	215	335	282	126	16	1	0	1064
040	CRAB ORCHARD 6 N	HDD	946	761	545	284	130	11	0	5	55	288	533	842	4400
		CDD	0	0	1	10	97	213	312	271	126	24	2	0	1056
043	CYNTHIANA	HDD	1075	861	671	376	162	17	0	5	57	333	615	930	5102
		CDD	0	0	0	5	86	210	328	285	120	21	0	0	1055
044	DANVILLE	HDD	1026	820	627	330	149	17	0	6	52	292	570	887	4776
		CDD	0	0	0	7	97	216	336	303	147	32	0	0	1138
045	DIX DAM	HDD	950	740	550	270	111	4	0	1	33	240	499	810	4208
		CDD	0	0	1	14	115	251	375	337	172	40	1	0	1306
050	EASTERN KENTUCKY UNIV	HDD	1036	820	628	327	136	12	0	5	52	296	567	890	4769
		CDD	0	0	0	6	95	214	338	289	128	24	0	0	1094
052	ELIZABETHTOWN WP 2	HDD	1064	831	653	348	158	10	0	2	41	296	592	902	4897
		CDD	0	0	0	4	71	206	332	302	153	23	0	0	1091
055	FALMOUTH	HDD	1118	881	702	389	179	22	1	11	59	347	632	967	5308
		CDD	0	0	0	4	78	191	305	275	107	14	0	0	974
056	FARMERS 2 S	HDD	1033	829	639	343	144	16	0	6	48	309	573	881	4821
		CDD	0	0	0	8	85	207	328	290	121	25	0	0	1064
061	FRANKFORT LOCK 4	HDD	1077	871	684	377	166	20	0	5	60	327	611	931	5129
		CDD	0	0	0	2	71	189	316	279	118	19	0	0	994
069	GILBERTSVILLE KY DAM	HDD	894	676	465	184	52	1	0	0	14	162	441	773	3662
		CDD	0	0	5	27	171	383	522	469	259	62	6	0	1904
070	GLASGOW	HDD	897	677	479	218	79	3	0	1	28	221	488	771	3862
		CDD	0	0	5	21	141	300	421	375	199	45	2	0	1509
072	GOLDEN POND 8 N	HDD	958	732	517	239	81	3	0	1	28	225	502	823	4109
		CDD	0	0	2	19	127	285	426	371	193	41	1	0	1465
073	GRAY HAWK	HDD	1085	877	710	423	202	34	4	11	86	395	661	960	5448
		CDD	0	0	0	1	48	131	239	203	75	14	0	0	711
074	GRAYSON 3 SW	HDD	1066	870	696	399	183	22	0	9	69	357	631	926	5228
		CDD	0	0	0	2	60	160	282	252	92	17	0	0	865
075	GREENSBURG	HDD	978	771	576	297	118	6	0	2	39	274	543	847	4451
		CDD	0	0	0	11	111	258	392	343	164	32	1	0	1312
078	HARDINSBURG	HDD	1015	764	556	267	101	7	0	2	37	249	543	864	4405
		CDD	0	0	3	15	115	245	365	324	157	32	1	0	1257
081	HEIDELBERG	HDD	1034	832	654	374	166	18	0	6	55	324	597	898	4958
		CDD	0	0	0	3	68	167	292	261	113	18	0	0	922
084	HENDERSON 7 SSW	HDD	1005	771	556	264	98	4	0	2	34	234	531	875	4374
		CDD	0	0	0	15	123	276	389	341	165	34	1	0	1344
087	HODGENVILLE-LINCOLN NP	HDD	964	731	531	265	111	6	0	2	44	256	529	841	4280
		CDD	0	0	0	12	99	224	344	306	153	32	1	0	1171
088	HOPKINSVILLE	HDD	988	766	543	255	93	4	0	1	36	242	517	853	4298
		CDD	0	0	2	23	127	286	410	364	179	40	2	0	1433

UNITED STATES DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
NATIONAL ENVIRONMENTAL SATELLITE DATA
AND INFORMATION SERVICE
NATIONAL CLIMATIC DATA CENTER
151 PATTON AVE ROOM 120
ASHEVILLE NC 28801-5001

September 17, 2007

The Department of Commerce's Bureau of Economic Analysis estimates at least 1/3 of the U.S. Gross Domestic Product is climate sensitive, a potential impact of $4 Trillion per year (in 2005 dollars), after inflation adjustment. This includes industries ranging from power generation to agriculture. NOAA has a responsibility to fulfill the mandate of Congress "to establish and record the climatic conditions of the United States" (Organic Act of 1890). One of the primary ways in which NOAA's NCDC carries out this responsibility is through the production of "climate normals" for temperature, i.e. the average temperature over a 30-year period at a given location. These normals are computed every 10 years; the most recent version covers the period from 1971 to 2000.

Climate normals are very important factors in commercial, industrial, agricultural, building, and transportation planning. The energy industry, in particular, is uniquely sensitive to climatic factors, including normals. This is from both an energy provider perspective and a regulatory perspective. From the provider perspective, climate normals are utilized for managing energy loads, assessing risk via weather derivatives of heating and cooling degree days, etc. From a regulatory perspective, NOAA NCDC's official climate normals are often invoked by regulators when determining what providers can charge customers. Not surprisingly, many energy providers include temperature data on customer bills, indicating the clear link between energy consumption and climate.

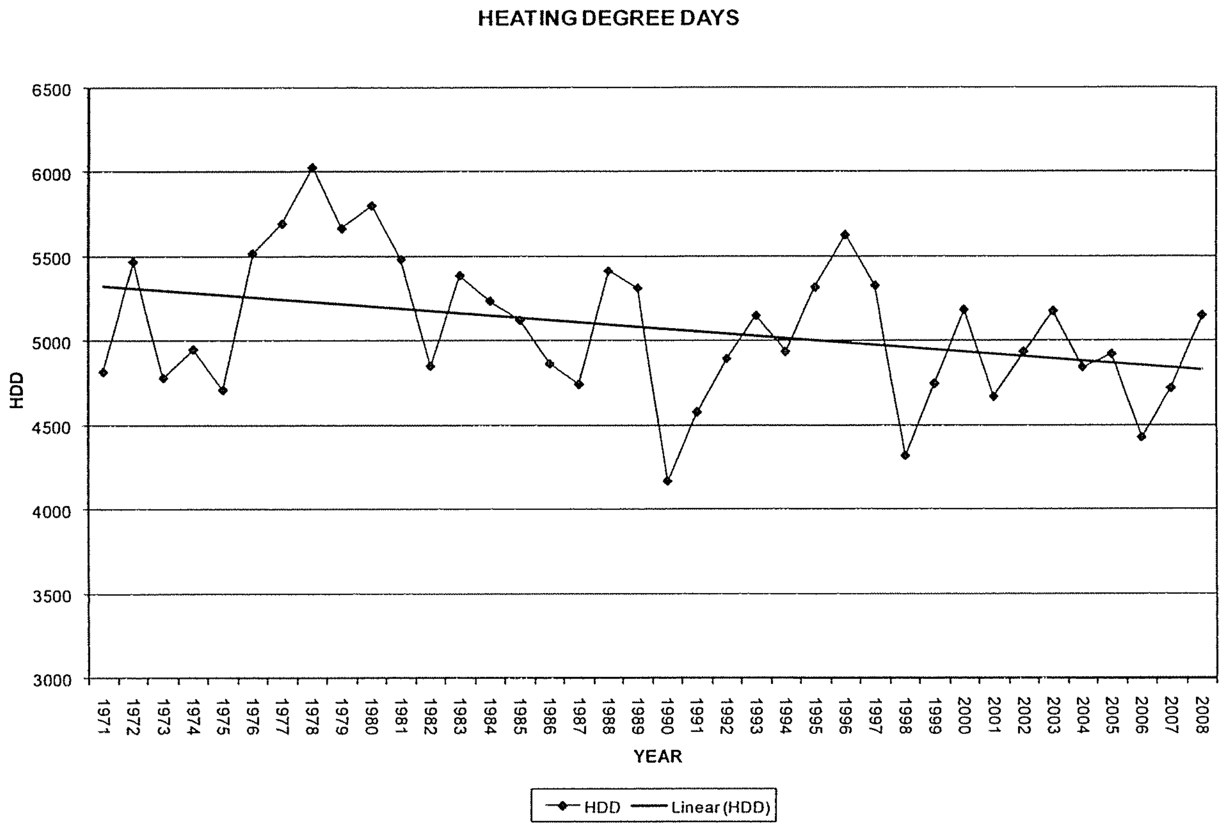
Climate normals are calculated retrospectively, but utilized prospectively. To complicate matters, NOAA NCDC's official climate normals are only made available every 10 years. The net result is a current-day energy regulator, for instance, may be forced to make a decision for the future based on data from 1971-2000. Producing climate normals that are more representative of the current state of the climate, at the time they are computed, is a major goal of our efforts. In addition, there is a clear need to create new normals that take into account artificial changes caused by changes in observation practice such as station moves and changes to instrumentation. NOAA's NCDC takes considerable care to ensure that the impact of station changes are minimized via its data homogenization and quality assessment algorithms.

There is also a need to create climate normals that take into account a changing climate. Climate normals were designed for climates that were thought to be relatively stationary, i.e. climates in which long-term averages do not vary a great deal in time. According to the Fourth Assessment Report of the Intergovernmental Panel of Climate Change (IPCC), however, there is virtually universal consensus that the climate has warmed relatively rapidly over the last 30 years. There is extensive evidence, as well as anecdotal evidence from the energy industry, that climate change is producing major impacts on the U.S. economy. In light of all of the aforementioned issues regarding the impact of climate normals on the industry, we look forward

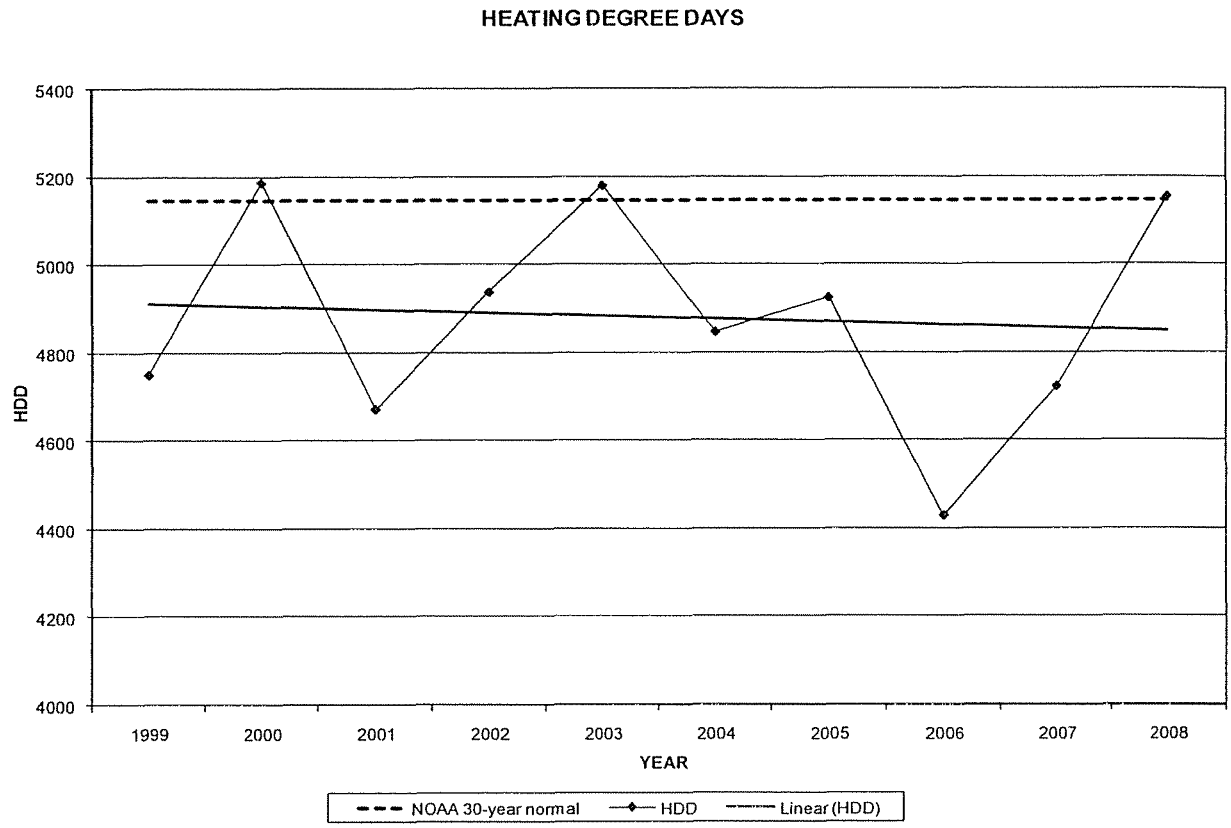
to continuing to work closely with all segments of the energy/utility industry to strategize on ways to provide better climate normals through "optimal" normals products in the future.

A NATIONAL RESOURCE FOR CLIMATE INFORMATION

Annual HDD
For Covington, Kentucky
1971 - 2008



Annual HDD
For Covington, Kentucky
1999 - 2008



Comparison of Actual HDD to NOAA Thirty-Year Normal

YEAR	HDD	NORMAL			MPE
1999	4,750	5,148		Below	8.4%
2000	5,187	5,148	Above		-0.8%
2001	4,672	5,148		Below	10.2%
2002	4,938	5,148		Below	4.3%
2003	5,180	5,148	Above		-0.6%
2004	4,847	5,148		Below	6.2%
2005	4,925	5,148		Below	4.5%
2006	4,430	5,148		Below	16.2%
2007	4,723	5,148		Below	9.0%
2008	5,155	5,148	Above		-0.1%
				Mean % Error	5.7%

Comparison of Actual HDD to DE-Kentucky Ten-Year Normal

YEAR	HDD	NORMAL			MPE
1999	4,750	4,881		Below	2.8%
2000	5,187	4,881	Above		-5.9%
2001	4,672	4,881		Below	4.5%
2002	4,938	4,881	Above		-1.2%
2003	5,180	4,881	Above		-5.8%
2004	4,847	4,881		Below	0.7%
2005	4,925	4,881	Above		-0.9%
2006	4,430	4,881		Below	10.2%
2007	4,723	4,881		Below	3.3%
2008	5,155	4,881	Above		-5.3%
				Mean % Error	0.2%

moderate consumption, while price increases both result from and contribute to changes in the mix of supply sources.

The reason for the large price variations across the cases is the need to turn to more expensive sources of supply to satisfy the demand for natural gas as consumption increases and available sources of supply diminish. With the exception of Alaska and unconventional natural gas, the domestic conventional natural gas resource base is largely depleted, and only limited production increases are possible in response to consumption increases. Most of the large conventional fields have already been discovered, leaving only the smaller and deeper fields that are more costly to develop.

In the limited electricity generation supply case, which assumes the same resource base and rate of technological progress as in the reference case, unconventional natural gas production increases in response to higher prices. The assumptions for the limited natural gas supply case limit technological progress and reduce the size of the resource base, causing a much greater price increase than in the limited electricity generation supply case. Increased demand for natural gas in the limited electricity generation supply case raises the natural gas wellhead price in 2030 to $7.57 per thousand cubic feet, compared with $6.63 per thousand cubic feet in the reference case. In the limited natural gas supply case, the wellhead price in 2030 is $9.61 per thousand cubic feet, and in the combined limited case it is $12.55 per thousand cubic feet.

Electricity Prices

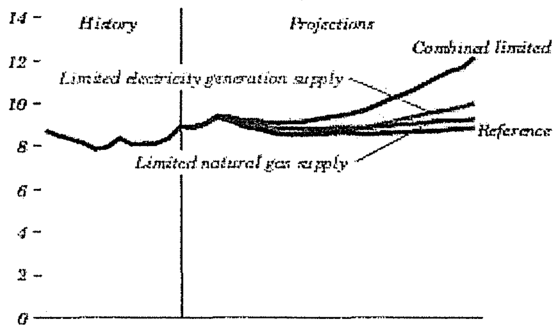
In the *AEO2008* reference case, real electricity prices are projected to remain relatively flat, with the 2030 price slightly below the current price. In the three limited cases, all with higher natural gas prices, electricity prices in 2030 are 4 percent to 36 percent higher than 2006 prices (Figure 20). Electricity prices in 2030 in the limited electricity generation supply case are higher than those in the limited natural gas supply case, even though natural gas prices are lower, because there are more options to change the generation mix in the limited natural gas supply case. In the limited electricity generation supply case, with capacity additions largely restricted to natural gas technologies, electricity prices are more sensitive to changes in natural gas prices and are 13 percent higher in 2030 than projected in the reference case. In comparison, electricity prices in 2030 in the limited natural gas supply case are 5 percent higher than in the reference case. In the combined limited case, electricity prices in 2030 are 37 percent higher than in the reference case.

Trends in Heating and Cooling Degree-Days: Implications for Energy Demand

Weather-related energy use, in the form of heating, cooling, and ventilation, accounted for more than 40 percent of all delivered energy use in residential and commercial buildings in 2006. Given the relatively large amount of energy affected by ambient temperature in the buildings sector, EIA has reevaluated what it considers "normal" weather for purposes of projecting future energy use for heating, cooling, and ventilation. In *AEO2008*, estimates of "normal" heating and cooling degree-days are based on the population-weighted average for the 10-year period from 1997 through 2006.

In previous *AEOs*, EIA used the National Oceanic and Atmospheric Administration (NOAA) 30-year average for heating and cooling degree-days as a benchmark for normal weather. Over the past several years, however, many energy analysts have questioned the use of the 30-year average, given the recent trend toward warmer weather relative to the 30-year average. Figure 21 shows percentage differences from the 30-year average in heating and cooling degree-days for the past 15 years. Over the 15-year period, only two winters have been colder, and all but three summers have been warmer, than the 30-year average; and on average, the winters have been 4 percent warmer and the summers 5 percent warmer than the 30-year average. Five of the 15 summers were more than 10 percent warmer than the 30-year average, whereas only 2 of the 15 winters were 10 percent

Figure 20. U.S. average electricity prices in four cases, 1995-2030 (2006 cents per kilowatthour)



warmer than the average, indicating a larger change for summer than for winter weather over the past 15 years. This suggests that the 30-year average is heavily weighted by years before 1993 and is less representative of heating and cooling degree-days in more recent years.

The recent changes in average heating and cooling degree-days have not only affected the accuracy of *AEO* projections for heating and cooling demand. Underestimating summer demand for cooling—particularly, peak demand—can undermine the plans made by electricity producers for wholesale power purchases and capacity additions. Overestimating winter demand for heating can affect plans for natural gas storage and supply. Consequently, many energy analysts have suggested that shorter time periods provide a more appropriate basis for projecting "normal" weather. For example, Cambridge Energy Research Associates, Inc., now uses a 15-year period (1991-2005) to estimate normal weather in its projections for heating and cooling degree-days [*63*], and NOAA, responding to customer feedback, has undertaken a process to revise its traditional 30-year average by creating "optimal climate normals" that will be more representative of current weather trends [*64*]. EIA decided to use the 10-year average to provide a better match with recent trends in heating and cooling degree-days.

Heating and Cooling Degree-Days in AEO2008

All the *AEO2008* projections use the 1997-2006 average as a proxy for normal weather from 2009 through 2030. The 10-year average is based on heating and cooling degree-day data by State, provided by NOAA, and State population weights provided by the U.S. Census Bureau. The State population projections allow for dynamic estimates of heating and cooling degree-days at the Census Division level. Where State populations are expected to shift within and across Census Divisions, the projections for average heating and cooling degree-days at the national level can vary from year to year.

Figure 21. Annual heating and cooling degree-days, 1993-2007 (percent difference from 30-year average)

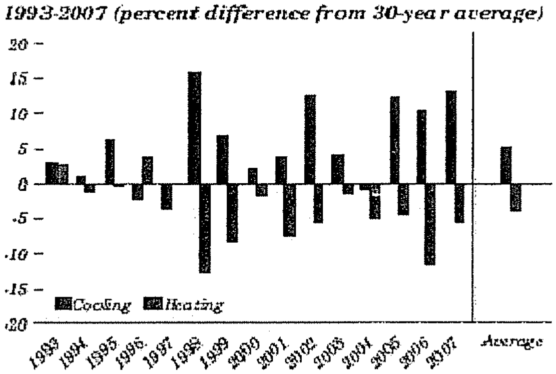


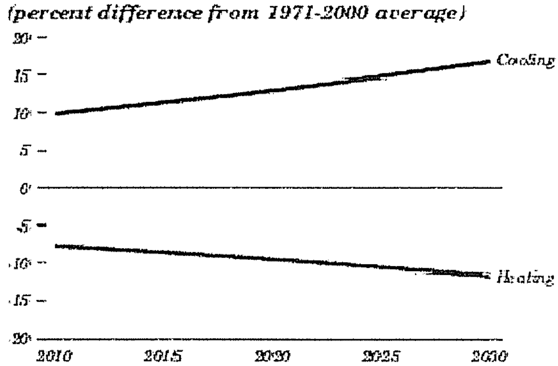
Figure 22 shows differences in heating and cooling degree-days in the *AEO2008* projection for 2010-2030 from the 1971-2000 30-year average published by NOAA. (It should be noted that the projection is not based on any assumption about global warming. Rather, expected U.S. population shifts cause the numbers of average heating and cooling degree-days to change over the projection period.) In 2010, the number of U.S. cooling degree-days in the *AEO2008* reference case is about 10 percent greater than the NOAA 30-year average with fixed population weights, and the number of heating degree-days is 8 percent less [*65*]. Accordingly, electricity providers are projected to see more peak summer demand, and direct fuel use for heating in buildings is projected to decline through 2030 as a result of State population shifts, all else being equal.

Impacts on the AEO2008 Projections

Fuel Use in Buildings and for Electricity Generation

Because space heating accounts for more direct energy use in buildings than does cooling, use of the 10-year averages for heating and cooling degree-days results in a 2.4-percent net decrease (about 0.6 quadrillion Btu) in buildings sector energy consumption in 2030, as compared with the same projection based on 30-year average heating and cooling degree-days (Figure 23). For electricity providers, on the other hand, the increase in electricity use for

Figure 22. Heating and cooling degree-days in the AEO2008 reference case, 2010-2030 (percent difference from 1971-2000 average)



NEMS Buildings Sector Working Group Meeting: AEO 2008 Data Development & Modeling Projects

EIA Buildings Team
June 28, 2007

Energy Information Administration
Official Energy Statistics from the U.S. Government

NEMS Buildings Projects for AEO 2008

- Residential
  - Change start year to 2005 based on pending RECS 2005
  - Update new housing shell characteristics based on new Census data, new version of REM-Design, and new Energy Star specs.
  - Update heating shares, square footage, etc. based on new data.
- Commercial
  - District Services update based on 2007 EEA Inc. Baseline Characterization of District Energy Systems
  - Refine 2003 CBECS EUIs
- Residential and Commercial
  - Update technology cost and performance data for major appliances and equipment based on 2007 Navigant findings
  - Update distributed generation modules to include niches and distributed wind. Base commercial penetration on IRR instead of years to postitive cumulative net cash flow.
  - **Change to 10 year average for 'normal' heating and cooling-degree days**
  - Update personal computer projections

Buildings Modeling Projects for AEO 2008 2

(Emphasis added)

Survey Questions **please answer for the models used for your financial plan.**

Your Name:
Your Company:

Weather

1. What is the definition for normal weather for your company's financial plan?

2. How often is the definition updated?

3. Why was this definition chosen?

Residential Model

1. Is the dependent variable of your residential model aggregate volume or volume per customer?

2. Do you have separate models for base load and temperature sensitive load or one model for both?

3. Is your dependent variable weather normalized or actual?

4. What are your independent variables? Please list the variables for the base load model and temperature-sensitive load model separately.

5. Do you use an end-use model for your financial plan?

6. What is the frequency of your model data? Monthly, quarterly, annual, other? If it is less frequent than monthly, do you allocate to months?

7. Do you adjust the forecasts based on your model to minimize the difference between the most recent actual values and the unadjusted/fitted values derived directly from your model?

Follow-up

Depending on your answers, we may want to call you with a few follow-up questions. If you are willing, please send your name and telephone number to

RESULTS

Survey of Gas Distribution Company Forecasting Practices
June 2007

15 respondents representing 35 companies

Definition of Normal Weather

Definition of Normal Weather

10-yr avg	10	29%
15-yr avg	1	3%
20-yr avg	6	17%
30-yr avg	18	51%
Total	35	100%

Rationale for Definition

Regulation	13	37%
Wx Trend	11	31%
None	11	31%
Total	35	100%

Update Schedule for Normal Wx

As Needed	10	29%
Annual	18	51%
10 years	6	17%
Rate Case	1	3%
Total	35	100%

Residential Models

Aggregate Volume or UPC

Aggregate	4	11%
UPC	31	89%
Total	35	100%

Total Model or Base/TS/End Use

Total	14	40%
B/TS/EU	18	51%
Growth Rate	3	9%
Total	35	100%

Actual or Normal Dep Variable

Actual	23	66%
Normal	12	34%
Total	35	100%

Model Data Frequency

Monthly	35	92%
Quarterly	1	3%
Annual	2	5%
Total	38	100%

Adjust Model for Last Observation(s)

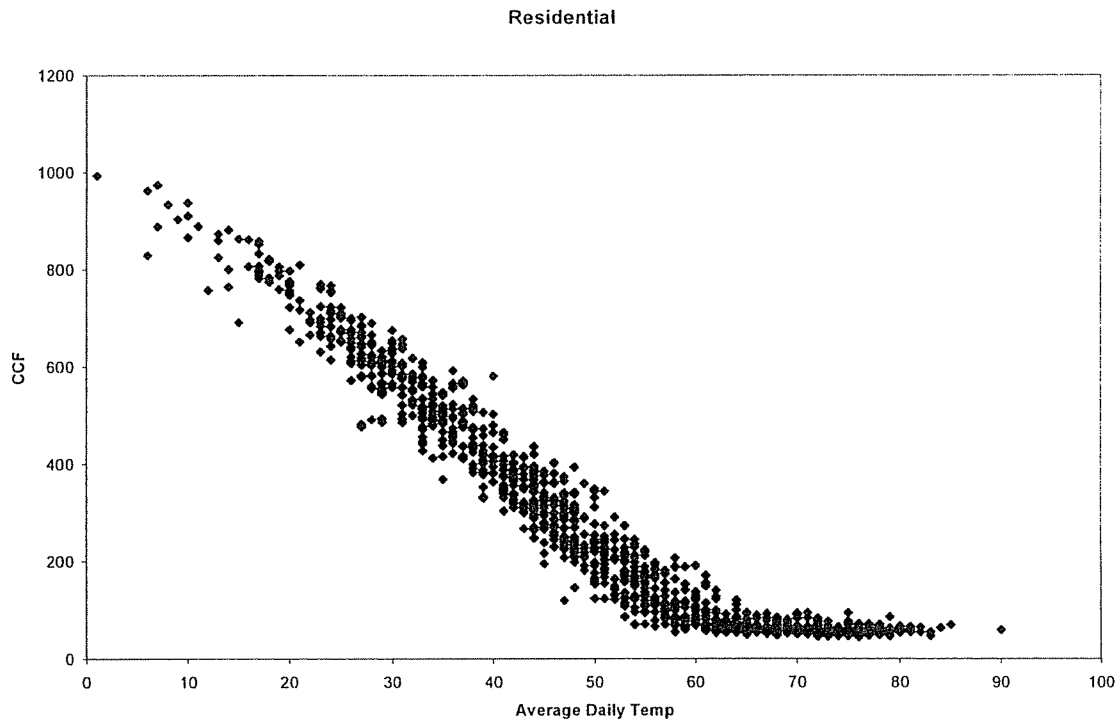
Yes	23	66%
No	12	34%
Total	35	100%

Trend Variable

Yes	16	46%
No	19	54%
Total	35	100%

Price Variable

Yes	20	57%
No	15	43%
Total	35	100%


Residential
1200
1000
800
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400
200
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0
10
20
30
40
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60
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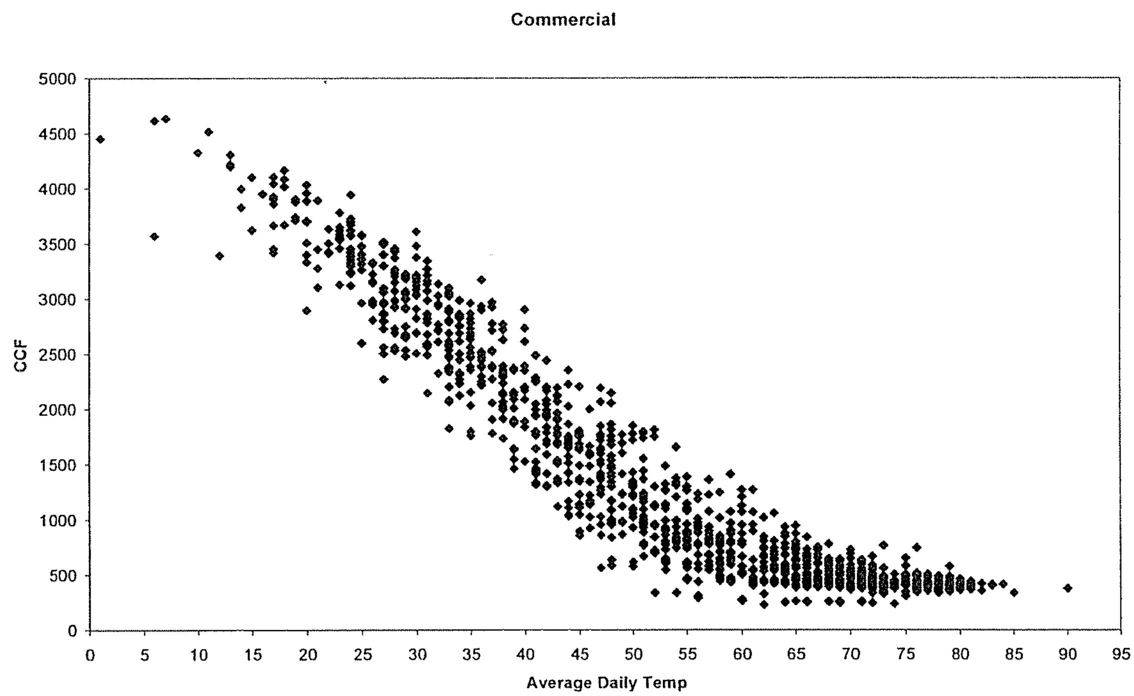
80
90
100
Average Daily Temp


Commercial
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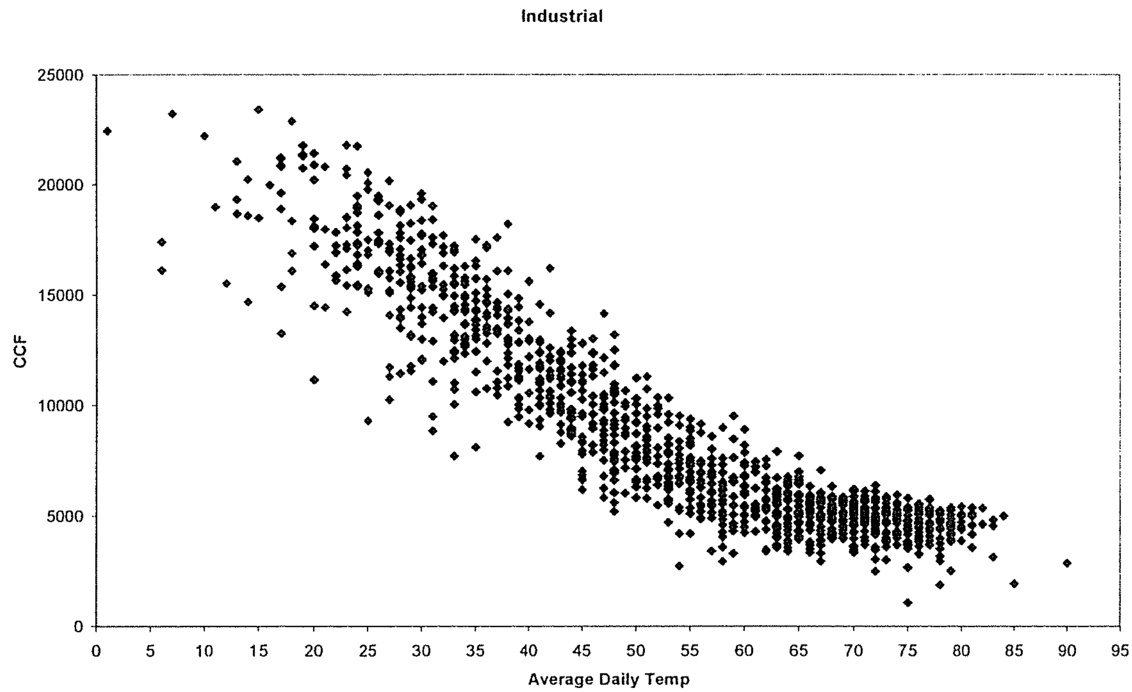
Average Daily Temp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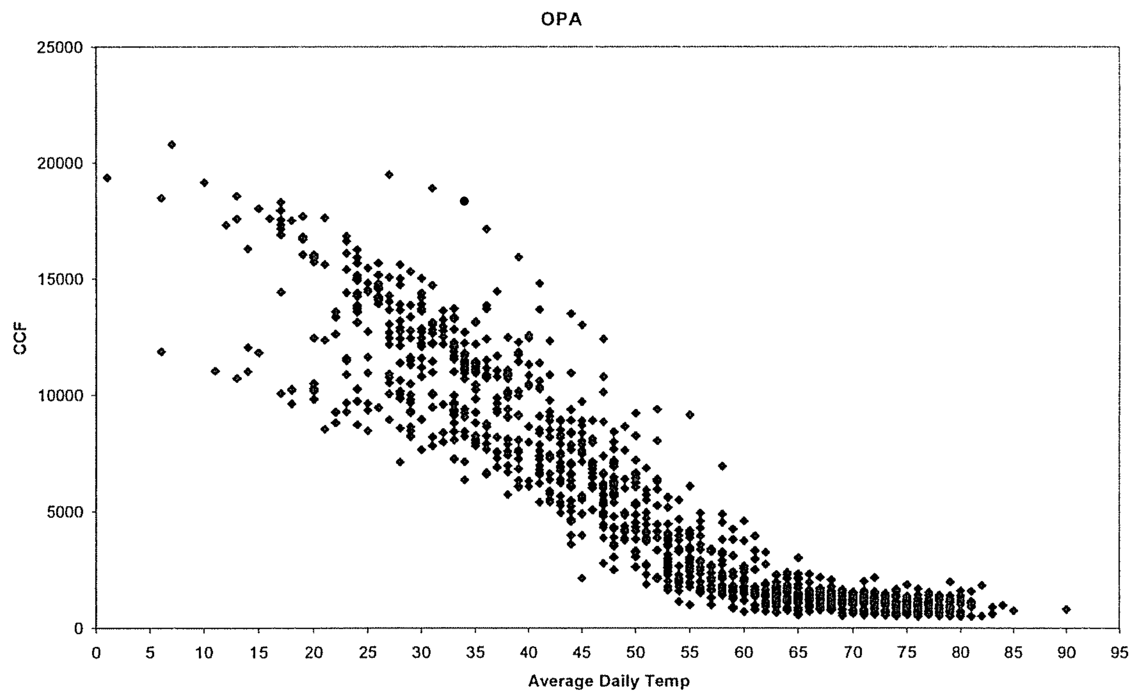
Average Daily Temp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Average Daily Temp

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN ADJUSTMENT	)	
OF GAS RATES OF	)	CASE NO. 2009-00202
DUKE ENERGY KENTUCKY, INC.	)	

DIRECT TESTIMONY OF

JOHN J. SPANOS

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

July 1, 2009

281171

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. ARE YOU ASSOCIATED WITH ANY FIRM?

A. Yes. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, Inc.

Q. HOW LONG HAVE YOU BEEN ASSOCIATED WITH GANNETT FLEMING VALUATION AND RATE CONSULTANTS, INC.?

A. I have been associated with the firm since college graduation in June 1986.

Q. WHAT IS YOUR POSITION WITH THE FIRM?

A. I am a Vice President.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

Q. DO YOU BELONG TO ANY PROFESSIONAL SOCIETIES?

A. Yes. I am a member of the Society of Depreciation Professionals and the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. DO YOU HOLD ANY SPECIAL CERTIFICATION AS A DEPRECIATION EXPERT?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003 and February 2008.

Q. PLEASE OUTLINE YOUR EXPERIENCE IN THE FIELD OF DEPRECIATION.

A. In June 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June 1986 through December 1995, I helped prepare numerous depreciation and original cost studies for utility companies in various industries. I helped perform depreciation studies for the following telephone companies: United Telephone of Pennsylvania, United Telephone of New Jersey and Anchorage Telephone Utility. I helped perform depreciation studies for the following companies in the railroad industry: Union Pacific Railroad, Burlington Northern Railroad and Wisconsin Central Transportation Corporation.

I helped perform depreciation studies for the following organizations in the electric industry: Chugach Electric Association, The Cincinnati Gas and Electric Company (CG&E), The Union Light, Heat and Power Company (now Duke Energy Kentucky), Northwest Territories Power Corporation and the City of Calgary - Electric System.

I helped perform depreciation studies for the following pipeline companies: TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

I helped perform depreciation studies for the following gas companies: Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, CG&E, Duke Energy Kentucky, Lawrenceburg Gas Company and Penn Fuel Gas, Inc.

I helped perform depreciation studies for the following water companies: Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service life and net salvage, calculated annual depreciation, and prepared reports for submission to state Public Utility Commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July 1999, I was promoted to the position of Manager, Depreciation and Valuation Studies. In December 2000, I was promoted to my present position as Vice-President of Gannett Fleming Valuation and Rate Consultants, Inc., and I became responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Pennsylvania-American Water Company; Aqua Pennsylvania; Kentucky-American Water Company; Virginia-American Water Company; Indiana-American Water Company; Hampton Water Works Company; Omaha Public Power District; Enbridge Pipe Line Company; Inc.; Columbia Gas of Virginia, Inc.; Virginia Natural Gas Company National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions; The City of Bethlehem - Bureau of Water; The City of Coatesville Authority; The City of Lancaster - Bureau of Water; Peoples Energy Corporation; The York Water Company; Public Service Company of Colorado; Enbridge Pipelines; Enbridge Gas Distribution, Inc.; Reliant Energy-HLP; Massachusetts-American Water Company; St. Louis County Water Company; Missouri-American Water Company; Chugach Electric Association; Alliant Energy; Oklahoma Gas & Electric Company; Nevada Power Company; Dominion Virginia Power; NUI-Virginia Gas Companies; Pacific Gas & Electric Company; PSI Energy; NUI - Elizabethtown Gas Company; Cinergy Corporation – CG&E; Cinergy Corporation – Duke Energy Kentucky; Columbia Gas of Kentucky; SCANA, Inc.; Idaho Power Company; El Paso Electric Company; Central Hudson Gas & Electric; Centennial Pipeline Company; CenterPoint Energy-Arkansas; CenterPoint Energy – Oklahoma; CenterPoint Energy – Entex; CenterPoint Energy - Louisiana; NSTAR – Boston Edison Company; Westar Energy, Inc.; PPL Electric

Utilities; PPL Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Duke Energy Carolinas; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Northern Indiana Public Service Company; Tennessee-American Water Company; Columbia Gas of Maryland; Bonneville Power Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc. and B. C. Gas Utility, Ltd. My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

Q. HAVE YOU SUBMITTED TESTIMONY TO ANY REGULATORY UTILITY COMMISSIONS ON THE SUBJECT OF UTILITY PLANT DEPRECIATION?

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission; the Commonwealth of Kentucky Public Service Commission; the Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the Public Utilities Board of New Jersey; the Missouri Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Alberta Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana Public Service Commission; the

State Corporation Commission of Kansas; the Oklahoma Corporate Commission; the Public Service Commission of South Carolina; Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; Illinois Commerce Commission; the Indiana Utility Regulatory Commission; the California Public Utilities Commission; the Federal Energy Regulatory Commission ("FERC"); the Arkansas Public Service Commission; the Public Utility Commission of Texas; Maryland Public Service Commission; Washington Utilities and Transportation Commission; The Tennessee Regulatory Commission; the Regulatory Commission of Alaska; and the North Carolina Utilities Commission.

Q. HAVE YOU HAD ANY ADDITIONAL EDUCATION RELATING TO UTILITY PLANT DEPRECIATION?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: "Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation" and "Managing a Depreciation Study." I have also completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

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

A. I sponsor filing requirement 10(9)(s), which is a depreciation study performed for Duke Energy Kentucky.

II. <u>DEPRECIATION STUDY</u>

Q. PLEASE DEFINE THE CONCEPT OF DEPRECIATION.

A. Depreciation refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which can be reasonably anticipated or contemplated, against which the Company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and the requirements of public authorities.

Q. DID YOU PREPARE THE DEPRECIATION STUDY FILED BY DUKE ENERGY KENTUCKY IN THIS PROCEEDING?

A. Yes. I prepared the depreciation study submitted by Duke Energy Kentucky with its filing in this proceeding. My report is entitled: "Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas and Common Plant as of December 31, 2008." This report sets forth the results of my depreciation study for Duke Energy Kentucky.

Q. IN PREPARING THE DEPRECIATION STUDY, DID YOU FOLLOW GENERALLY ACCEPTED PRACTICES IN THE FIELD OF DEPRECIATION VALUATION?

A. Yes.

Q. PLEASE DESCRIBE THE CONTENTS OF YOUR REPORT.

A. My report is presented in three parts. Part I, Introduction, presents the scope and basis for the depreciation study. Part II, Methods Used in Study, includes descriptions of the basis of the study, the estimation of survivor curves and net salvage and the calculation of annual and accrued depreciation. Part III, Results of Study, presents a description of the results, summaries of the depreciation calculations, graphs and tables that relate to the service life and net salvage analyses, and the detailed depreciation calculations.

The table on pages III-4 and III-5 presents the estimated survivor curve, the net salvage percent, the original cost as of December 31, 2008, the book reserve and the calculated annual depreciation accrual and rate for each account or subaccount. The section beginning on page III-6 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page III-131 presents the results of the salvage analysis. The section beginning on page III-160 presents the depreciation calculations related to surviving original cost as of December 31, 2008.

Q. PLEASE EXPLAIN HOW YOU PERFORMED YOUR DEPRECIATION STUDY.

A. I used the straight line remaining life method of depreciation, with the equal life group procedure. The annual depreciation is based on a method of depreciation accounting that seeks to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit, or group of assets, in a systematic and reasonable manner.

For General Plant Accounts 1910, 1930, 1940, 1970, 1980 in common plant and 2910, 2940 and 2980 in gas plant, I used the straight line remaining life method of amortization. The account numbers identified throughout my testimony represent those in effect as of December 31, 2008. The annual amortization is based on amortization accounting that distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account and vintage.

Q. HOW DID YOU DETERMINE THE RECOMMENDED ANNUAL DEPRECIATION ACCRUAL RATES?

A. I did this in two phases. In the first phase, I estimated the service life and net salvage characteristics for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In the second phase, I calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

Q. PLEASE DESCRIBE THE FIRST PHASE OF THE DEPRECIATION STUDY, IN WHICH YOU ESTIMATED THE SERVICE LIFE AND NET SALVAGE CHARACTERISTICS FOR EACH DEPRECIABLE GROUP.

A. The service life and net salvage study consisted of compiling historical data from records related to Duke Energy Kentucky's plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning practices and plans as they relate to plant operations; and interpreting the above data and the estimates used by other gas utilities to form judgments of average service life and net salvage characteristics.

Q. WHAT HISTORICAL DATA DID YOU ANALYZE FOR THE PURPOSE OF ESTIMATING SERVICE LIFE CHARACTERISTICS?

A. I analyzed the Company's accounting entries that record plant transactions during the period 1956 through 2008. The transactions included additions, retirements, transfers, sales and the related balances. The Company records included surviving dollar value by year installed for each plant account as of December 31, 2008.

Q. WHAT METHOD DID YOU USE TO ANALYZE THIS SERVICE LIFE DATA?

A. I used the retirement rate method. This is the most appropriate method when retirement data covering a long period of time is available, because this method determines the average rates of retirement actually experienced by the Company during the period of time covered by the depreciation study.

Q. PLEASE DESCRIBE HOW YOU USED THE RETIREMENT RATE METHOD TO ANALYZE DUKE ENERGY KENTUCKY'S SERVICE LIFE DATA.

A. I applied the retirement rate analysis to each different group of property in the study. For each property group, I used the retirement rate data to form a life table which, when plotted, shows an original survivor curve for that property group. Each original survivor curve represents the average survivor pattern experienced by the several vintage groups during the experience band studied. The survivor patterns do not necessarily describe the life characteristics of the property group; therefore, interpretation of the original survivor curves is required in order to use them as valid considerations in estimating service life. The Iowa type survivor curves were used to perform these interpretations.

Q. WHAT IS AN "IOWA-TYPE SURVIVOR CURVE" AND HOW DID YOU USE SUCH CURVES TO ESTIMATE THE SERVICE LIFE CHARACTERISTICS FOR EACH PROPERTY GROUP?

A. Iowa type curves are a widely-used group of survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.

Iowa type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves and truncated Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements.

The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. For example, the Iowa 55-R2.5 indicates an average service life of fifty-five years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a moderate height, 2.5, for the mode (possible modes for R type curves range from 1 to 5).

Q. PLEASE DESCRIBE HOW THE ACCELERATED MAIN REPLACEMENT PROGRAM IMPACTED THIS STUDY.

A. The Accelerated Main Replacement Program (AMRP) was utilized in Account 2761, Main – Cast Iron, Copper and All Valves, and Account 2801, Services – Cast Iron, Copper and Valves. This program has been in place since 2000 and will continue through September 2010 when virtually all 12-inch and smaller diameter cast iron mains and associated services will be replaced. Therefore, the projected retirements for the years 2009 and 2010 were included in the life analysis for these accounts in order to properly incorporate historical statistics with future expectations of service life for these assets. The estimated survivor curves for the experience band 1956 through 2010 are plotted on page III-31 of the depreciation study for Account 2761, and page III-63 for Account 2801. There is no anticipated affect on the estimated plastic and steel mains or services due to AMRP.

Q. HAS THE IMPLEMENTATION OF AMRP DATA THROUGH 2010 AFFECTED THE PROPOSED DEPRECIATION RATES?

A. Yes, the utilization of the 2009 and 2010 data has properly estimated the life characteristics of cast iron assets in the two accounts. Consequently, the proposed depreciation accrual rates of 5.25% for Account 2761 and 2.86% for Account 2801 will match the appropriate recovery level to useful life of cast iron investment in these two accounts by the time most assets are retired in 2010.

Q. PLEASE DESCRIBE HOW YOU ESTIMATED NET SALVAGE PERCENTAGES.

A. I estimated the net salvage percentages by incorporating the historical data for the period 1980 through 2008 and considered estimates for other gas companies.

Q. PLEASE DESCRIBE THE SECOND PHASE OF THE PROCESS THAT YOU USED IN THE DEPRECIATION STUDY IN WHICH YOU CALCULATED COMPOSITE REMAINING LIVES AND ANNUAL DEPRECIATION ACCRUAL RATES.

A. After I estimated the service life and net salvage characteristics for each depreciable property group, I calculated the annual depreciation accrual rates for each group, using the straight line remaining life method, and using remaining lives weighted consistent with the equal life group procedure.

Q. PLEASE DESCRIBE THE STRAIGHT LINE REMAINING LIFE METHOD OF DEPRECIATION.

A. The straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life.

Q. PLEASE DESCRIBE THE EQUAL LIFE GROUP PROCEDURE.

A. The equal life group procedure is a method for determining the remaining life annual accrual for each vintage property group. Under this procedure, the future book accruals (original cost less book reserve) for each vintage are divided by the composite remaining life for the surviving original cost of that vintage. The vintage composite remaining life is derived by summing the original cost less the calculated reserve for each equal life group and dividing by the sum of the whole life annual accruals.

Q. PLEASE DESCRIBE AMORTIZATION ACCOUNTING.

A. In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. Amortization accounting is used for accounts with a large number of units but small asset values; therefore, depreciation accounting is difficult for these assets because periodic inventories are required to properly reflect plant in service. Consequently, retirements are recorded when a vintage is fully amortized rather than as the units are removed from service. That is, there is no dispersion of retirement. All units are retired when the age of the vintage reaches the amortization period. Each plant account or group of assets is assigned a fixed period which represents an anticipated life which the asset will render full benefit. For example, in amortization accounting, assets that have a 20-year amortization period will be fully recovered after 20 years of service and taken off the Company books but not necessarily removed from service. In contrast, assets that are taken out of service before 20 years remain on the books until the amortization period for that vintage has expired.

Q. AMORTIZATION ACCOUNTING IS BEING IMPLEMENTED TO WHICH PLANT ACCOUNTS?

A. Amortization accounting is only appropriate for certain Common and General Plant accounts. These accounts are 1910, 1930, 1940, 1970, 1980 for Common Plant; and 2910, 2940 and 2980 for General Plant which represent approximately two percent of depreciable plant.

Q. PLEASE USE AN EXAMPLE TO ILLUSTRATE HOW THE ANNUAL DEPRECIATION ACCRUAL RATE FOR A PARTICULAR GROUP OF PROPERTY IS PRESENTED IN YOUR DEPRECIATION STUDY.

A. I will use Account 2762, Mains - Steel, as an example because it is the largest depreciable group and represents 20% of depreciable plant.

The retirement rate method was used to analyze the survivor characteristics of this property group. Aged plant accounting data was compiled from 1956 through 2008 and analyzed in periods that best represent the overall service life of this property. The life tables for the 1956-2008 and 1979-2008 experience bands are presented on pages III-39 through III-44 of the report. The life tables display the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page III-39 shows $16,845 retired at age 0.5 with $72,744,417 exposed to retirement. Consequently, the retirement ratio is 0.0002 and the surviving ratio is 0.9998. These life tables, or original survivor curves, are plotted along with the estimated smooth survivor curve, the 55-R2.5 on page III-38.

My calculation of the annual depreciation related to the original cost at December 31, 2008, of utility plant is presented on pages III-179 through III-181. The calculation is based on the 55-R2.5 survivor curve, 20% negative net salvage, the attained age, and the allocated book reserve. The tabulation sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. These totals are brought forward to the table on page III-4.

III. CONCLUSION

Q. WAS THE DEPRECIATION STUDY FILED BY DUKE ENERGY KENTUCKY IN THIS PROCEEDING PREPARED BY YOU OR UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

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

A. Yes.

VERIFICATION

Commonwealth Pennsylvania)
) **SS:**
County of Cumberland)

The undersigned, John J. Spanos, being duly sworn, deposes and says that he is a Vice President associated with the firm of Gannett Fleming in its Valuation and Rate Division, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

John J. Spanos
John J. Spanos, Affiant

Subscribed and sworn to before me by John J. Spanos on this 11th day of June, 2009.

NOTARY PUBLIC

My Commission Expires:

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Cheryl Ann Rutter, Notary Public
East Pennsboro Twp., Cumberland County
My Commission Expires Feb. 20, 2011
Member, Pennsylvania Association of Notaries

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN ADJUSTMENT	)	
OF GAS RATES OF	)	CASE NO. 2009-00202
DUKE ENERGY KENTUCKY, INC.	)	

DIRECT TESTIMONY OF

DONALD L. STORCK

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

July 1, 2009

269448

TABLE OF CONTENTS

PAGE

ATTACHMENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Donald L. Storck. 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, Inc., an affiliate service company of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company), as a Director, Rates Services.

Q. PLEASE SUMMARIZE YOUR EDUCATION.

A. I have a Bachelor of Science Degree in Accounting from Ball State University. I completed an executive education program at the University of Michigan.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. I began my employment with PSI Energy, Inc. (PSI), in 1976, as a Staff Accountant in the Corporate Accounting Department. From 1976 through 1994, I held several financial positions at PSI and at various times was responsible for Corporate Accounting, Cash Management, Corporate Budgeting and auditing of long-term fuel supply contracts. Following the 1994 merger between PSI and The Cincinnati Gas & Electric Company to form Cinergy Corp. (Cinergy), I held positions with the Cinergy affiliated companies, supporting the Gas Business Unit and Cinergy Resources, Inc., a non-regulated retail gas marketing company.

I became the Financial Reporting Manager for Cinergy's Regulated Business Unit from 1999 until April 2006. I was promoted to my current position in April 2006.

Q. PLEASE DESCRIBE YOUR DUTIES AS DIRECTOR, RATE SERVICES.

A. My responsibilities include developing cost-of-service studies and tariff administration.

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

A. No.

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

A. I sponsor schedules B-7, B-7.1, B-7.2, D-3, D-4, and D-5 the cost of service study identified as Filing Requirement (FR) FR 10(9)v-1 through FR 10(9)v-5 and the distribution of the proposed revenue.

II. <u>SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS</u>

Q. PLEASE DESCRIBE SCHEDULES B-7 AND D-3.

A. These schedules report the allocation factors used to determine the jurisdictional percentages of gas plant, expenses, *etc.*, necessary to allocate the amount of the proposed new gas rates between jurisdictional and non-jurisdictional customers. These schedules indicate that 100% of the costs are jurisdictional, because Duke Energy Kentucky does not have any non-jurisdictional gas customers within its service territory.

Q. PLEASE DESCRIBE SCHEDULES B-7.1 AND D-4.

A. These schedules are the support for Schedules B-7 and D-3 described above. They provide the basis for the actual jurisdictional allocation factors. These schedules also show that 100% of Duke Energy Kentucky's gas costs are jurisdictional.

Q. PLEASE DESCRIBE SCHEDULES B-7.2 AND D-5.

A. These schedules explain changes made to the jurisdictional allocation from the Company's prior gas rate proceeding in Case No. 2005-00042. In Duke Energy Kentucky's last gas rate case, 100% of its costs were also jurisdictional. As a result, there were no changes in the jurisdictional allocation factors used in this proceeding.

Q. PLEASE DESCRIBE FR 10(9)v-1 THROUGH FR 10(9)v-5.

A. FR10 (9)v-1 through FR 10(9)v-5 is a fully allocated, embedded cost of service study by rate class.

III. <u>COST OF SERVICE STUDIES</u>

Q. WHAT IS THE PURPOSE OF A COST OF SERVICE STUDY?

A. The purpose of a Cost of Service Study is to allocate a utility's cost of service among the different customer classes which are responsible for causing these costs. After the costs are assigned to the appropriate customer classes, rates are designed to provide the Company with an opportunity to generate a stream of revenues to recover these costs.

Q. WHAT INFORMATION DID THE COMPANY USE TO DEVELOP THE COST ALLOCATION FACTORS FOR THE COST OF SERVICE STUDIES USED IN THIS PROCEEDING?

A. The test period for this proceeding is the twelve months ending January 31, 2011, which is comprised of forecasted data. The development of the test period allocation factors is based on historical data. I will discuss the development of the various allocation factors used in this proceeding later in my testimony.

Q. PLEASE DESCRIBE THE TYPE OF COST OF SERVICE STUDY YOU USED IN THIS PROCEEDING.

A. The basic cost of service study is an embedded or fully allocated cost of service study by rate class for the forecasted test period ended January 31, 2011, as adjusted. This cost of service study allocates cost in categories such as plant, expenses and taxes among the various customer classes and calculates the revenue responsibility for each class. This Cost of Service Study is at FR 10(9)v-1 through FR 10(9)v-5.

Q. HOW IS THE COST OF SERVICE STUDY ORGANIZED?

A. Schedule 1 of the cost of service study contains a summary of the cost of service. Schedules 2 through 10 and Schedule 12 show the complete detail of all the elements of the cost of service study. Schedules 11 and 13 list the allocation factors, tax rates, and rate of return data that were utilized in the cost of service study. The detailed calculation and derivation of the allocation factors used in the cost of service study are included in the work papers filed in this case.

Q. WHAT JURISDICTIONAL CUSTOMER CLASSES WERE USED IN THE COST OF SERVICE STUDIES?

A. I used the following customer classes; RS-Residential, GS-General Service, FT-Firm Transportation and IT- Interruptible Transportation.

Q. PLEASE LIST EACH ELEMENT OF THE COST OF SERVICE STUDIES THAT YOU PREPARED.

A. The elements of a cost of service study are the following:

Operating & Maintenance Expense

+ Depreciation
+ Other Taxes
+ Federal Income Tax
+ State Income Tax
+ Return
+ AFUDC Offset
- Revenue Credits
= Revenue Requirement or Cost of Service

Q. HOW DID YOU DEVELOP THE BASIC COST OF SERVICE STUDY THAT YOU USED TO ALLOCATE COSTS TO THE DIFFERENT CUSTOMER CLASSES?

A. First, I received functionalized costs, *i.e.*, production and distribution, from Duke Energy Kentucky witness Mr. Robert M. Parsons. Then, I developed the classification factors based on customer, commodity and demand statistics for the test period. Finally, I made the allocation to rate classes based on the general principles outlined in the National Association of Regulatory Utility Commissioners (NARUC) Gas Distribution Rate Design Manual, Chapter 7, *Cost Allocation Studies*, of the AGA book *Gas Rate Fundamentals* (4^{th} edition), my utility company experience and my knowledge of cost-of-service studies.

Q. PLEASE DESCRIBE THE METHODOLOGY USED TO ALLOCATE PRODUCTION PLANT AND OTHER DEMAND RELATED ITEMS TO THE VARIOUS CLASSES OF CUSTOMERS.

A. The average and excess method (also known as the average and peak demand method) was used in the allocation of these items. The Company has a gas load research program, which allows us to determine the class coincident peaks utilized in this methodology.

Q. PLEASE DESCRIBE THE AVERAGE AND EXCESS DEMAND METHOD OF ALLOCATION.

A. As noted in the NARUC Gas Distribution Rate Design Manual, this method reflects a compromise between the coincident and non-coincident demand methods. Total demand costs are multiplied by the system's load factor to arrive at the capacity costs attributed to average use and are apportioned to the various customer classes on an annual volumetric basis. The remaining costs are considered to have been incurred to meet the individual peak demands of the various classes of service and are allocated on the basis on the coincident peak of each class.

Q. DO YOU HAVE AN OPINION REGARDING WHETHER THIS IS A REASONABLE ALLOCATION METHOD TO USE?

A. Yes. The average and excess demand method is a reasonable cost allocation method to use because: (1) shifts in the system peak do not greatly affect the allocation, as would happen in the coincident peak method; (2) the allocation of unused capacity is similar to the non-coincident demand method, except that it is applied only to the excess of class peak day demands above the average daily demand; and (3) this method gives recognition to load-factor.

Q. HOW DID THE COMPANY DEVELOP CLASS COINCIDENT PEAK DAY DEMAND DATA?

A. Load research data and historical volumes were developed by the Company and utilized to determine peak day demand data. This information is included on Pages 1, 3 and 4 of the cost of service study workpapers WPFR-9v-6. The following is an example of how the demands were calculated for Rate RS for the month of January.

Step 1 - Determine the average daily demand by dividing the monthly weather normalized volumes by the number of days in the month.

1,058,731Mcf ÷ 31 days =34,153 Mcf/day

Step 2 - Determine the daily class coincident peak demand by dividing the average daily demand, from Step 1, by the coincident peak load factor, which was obtained from load research data.

34,153Mcf/day ÷ .5853 = 58,351Mcf/day

This process was followed for each rate class for each month to determine each rate class' monthly coincident peak day demand. The coincident peak day demands for the peak month were then used to develop the average and excess demand allocators in the cost-of-service studies. My calculation of the coincident peak day demand factors for each rate class is at workpaper WPFR-9v-6, pages 6-7.

Q. WHAT COSTS DID YOU ALLOCATE BY USING THE AVERAGE AND EXCESS DEMAND COST ALLOCATORS?

A. Using the average and excess demand formula, I calculated two peak day demand factors K203 and K205. I used allocation factor K203 to allocate all the rate classes the demand component of the following costs: system measuring and regulating equipment, regulators, mains, and associated land, rights of way, structures and improvements. I used allocation factor K205 to allocate production facilities and related demand, operating and maintenance (O&M) costs among rate classes.

Q. WHAT METHOD DID YOU USE TO ALLOCATE ADMINISTRATIVE AND GENERAL EXPENSES?

A. I used a two step approach. First, I functionalized Administrative and General (A&G) expenses based on specific groupings of employee salaries and wages. These groupings include Production Demand, Production Commodity, Distribution, Customer Accounting, Customer Service and Information and Sales. I then allocated these expenses to each rate class based on (O&M) expense allocation factors. For example, I allocated the A&G expense as production demand plant to each rate class based on the demand-related production O&M expense allocator. I used the same procedure to allocate the other A&G expenses to each rate class. I used the K411 allocation factor for adjustments to all A&G costs throughout the basic Cost of Service Study. The K411 allocation factor simply consists of the sum of the weighted functionalized A&G expenses by class. This is the same procedure used in Case Nos. 2001-00092 and 2005-00042.

Q. HOW DID YOU ALLOCATE THE REMAINING DISTRIBUTION PLANT COSTS TO THE VARIOUS CUSTOMER CLASSES?

A. I allocated the costs for large industrial measuring and regulating plant by using allocator K595, based on Mcf ratios, excluding residential, commercial and interdepartmental Mcf. This equipment serves the industrial customers of the General Service, Firm Transportation and Interruptible Transportation Service rate groups.

I allocated the services based upon weighted customer ratios. I calculated the weighting factors by using the average cost of the different types and sizes of services. I allocated the meter and meter installation costs using ratios developed from a meter cost study. I allocated house regulator and regulator installation costs based upon the weighted ratios within each rate class.

Q. HOW DID YOU ALLOCATE THE COSTS FOR COMMON AND GENERAL PLANT?

A. I functionalized the common and general plant costs into specific functional categories using my earlier functionalization of the labor costs. I allocated these costs to each rate class based on how much of the direct O&M for that specific function had been allocated to each rate class. This was the same method I used to allocate A&G expenses.

Q. HOW DID YOU ALLOCATE CONSTRUCTION WORK IN PROGRESS (CWIP) COSTS?

A. I allocated distribution Construction Work in Progress (CWIP) costs based on the weighted gross plant ratio.

Q. HOW DID YOU ALLOCATE THE ADJUSTMENTS THAT WERE SUBTRACTED FROM RATE BASE?

A. I allocated the following items based on the net plant ratios for each rate class: liberalized depreciation, contributions in aid of construction, customer advances for construction, capitalized interest, and investment tax credit. I allocated miscellaneous deferrals based on the A&G cost allocation. I allocated deferred unrecovered purchased gas costs to the rate class based on the firm Mcf sales ratio.

Q. HOW DID YOU ALLOCATE ADJUSTMENTS THAT WERE ADDED TO RATE BASE?

A. I used the A&G expense cost factor K411, to allocate the amounts reflected in the Accumulated Deferred Income Tax Account 190. Items included in this account relate to post-retirement and pension benefits, vacation pay accruals, deferred compensation benefits, and miscellaneous deferrals.

Q. HOW DID YOU ALLOCATE WORKING CAPITAL?

A. Working capital consists of the following items: materials and supplies, prepayments, cash, and other miscellaneous items. Propane and materials and supplies were allocated based on the peak and average demand allocator, K205 and net plant ratios, respectively. Cash working capital is a simple calculation equal to 1/8 of O&M expense minus the cost of gas.

Q. HOW DID YOU ALLOCATE PRODUCTION OPERATION AND MAINTENANCE EXPENSES?

A. I used firm Mcf sales to allocate the demand and commodity-related production expenses. I allocated the other production expenses by using the peak and average demand allocation factor K205.

Q. HOW DID YOU ALLOCATE DISTRIBUTION OPERATION AND MAINTENANCE EXPENSES?

A. I allocated load dispatching, and rent costs based on total annual Mcf sales allocator

K300. I allocated mains and services operating expenses based on mains and services plant cost allocation ratio K667. I allocated measuring and regulating station expenses based on the peak and average demand cost allocator K203. I allocated customer installation and other distribution expenses based on the combination customer/ demand cost allocation factor K415.

I allocated meter and house regulator O&M expenses based on meter and house regulator plant cost allocation allocator K697. I allocated mains maintenance expense based on allocator K203 for the customer portion and K401 for the demand portion, similar to the allocation of mains' plant costs. I allocated services maintenance expense based on the weighted customer-services ratio K403, similar to the allocation of services' plant costs. I allocated supervision and engineering expenses based on the total distribution plant cost allocation ratio D249. I allocated industrial measuring and regulating expenses based on the same ratio as the industrial measuring and regulating plant cost allocation ratio, K595. I allocated expenses related to elimination of the non Duke Energy Kentucky portion of Accounts 874 and 887, mains and services expenses and maintenance of mains, based on the weighted gross distribution plant allocator.

Q. HOW DID YOU ALLOCATE CUSTOMER ACCOUNTING, UNCOLLECTIBLE ACCOUNTS, CUSTOMER SERVICE AND INFORMATION, AND SALES EXPENSES?

A. Customer Accounting includes Accounts 901, 902, 903 and 905 and was allocated to class based on allocator K405. Uncollectible expense is recorded in Account 904 and was allocated using K406. Customer Service & Information includes Account

907, 908, 909, and 910 and was allocated using K407. Sales Expense includes 911, 912, and 913. Sales expense was allocated using K408.

Each of allocators K405, K406, K407, and K408 were derived from other allocators in a two-step process. First, each Account was allocated to rate class. Accounts 901, 903, 905, and 908-911 were allocated to rate class based on allocator K401, total customers. The allocation of Account 902 meter reading expense is based on meter cost allocator K413. Expenses in Account 904 were allocated to rate classes based on a residential/non-residential charge-off allocator K406.

Second, the accounts by rate class within each allocator were added. To derive Customer Accounting Expense Allocator K405, for example, the amounts allocated to each class in Accounts 901, 902, 903 and 905 were summed up to get the total RS, GS, IT and FT amounts for Customer Accounting Expense. Allocator K405 was then calculated by taking the ratio in each rate class (RS, GS IT and FT) to total Customer Accounting Expense. Allocator K405 was then applied to test year Customer Accounting Expense. A similar process was used for Customer Service and Information Expense and Sales Expense.

Q. HOW DID YOU ALLOCATE DEPRECIATION EXPENSES?

A. I allocated depreciation expenses to rate class based on the class net plant ratios.

Q. HOW DID YOU ALLOCATE REAL ESTATE AND PROPERTY TAXES?

A. I allocated real estate and property taxes to rate class based on the weighted class net plant ratio NP29.

Q. HOW DID YOU ALLOCATE PAYROLL AND HIGHWAY TAXES, THE PSC ASSESSMENT AND OTHER MISCELLANEOUS TAXES?

A. I allocated the PSC Maintenance Taxes to class based on K901, present revenues. I allocated Payroll and Other Miscellaneous Taxes to rate class based the class-weighted A&G expense ratio K411.

Q. HOW DID YOU ALLOCATE FEDERAL AND STATE INCOME TAXES?

A. I reviewed each income tax component to determine the functional cause of the component then selected the appropriate allocation factor. For example, Depreciation in Excess of Book Depreciation was allocated to the rate classes based on the appropriate class depreciation expense ratio.

Q. HOW DID YOU ALLOCATE OTHER OPERATING REVENUES?

A. Miscellaneous service revenues and other gas revenues from bad check and reconnection charges were allocated to class based on the ratio K401, customers by class to the total. Revenues from the transportation of gas for associated companies and interdepartmental sales were allocated to class based on customer class present revenues allocation ratio K901. I allocated the allowance of funds used during construction (AFUDC) offset adjustment due to CWIP based on weighted CWIP plant cost allocation ratio CW29.

Q. WHAT DO THE RESULTS OF THE PROPOSED COST OF SERVICE STUDY SHOW?

A. Based on the allocation assumptions made and the rate of return of approximately 7.671% requested in this proceeding, the cost of service justifies a gas revenue increase of approximately $17.5 million for the forecasted test period ending January 31, 2011, as adjusted for known and measurable changes.

Q. HOW DID YOU DETERMINE THE PROPOSED REVENUE

DISTRIBUTION FOR THIS PROCEEDING?

A. First, I eliminated 100% of the interclass subsidies between customer classes based on present revenues. I then allocated the proposed rate increase to customer classes based on the class allocation of capitalization allocated to gas operations.

Q. WHY DID YOU PROPOSE THE REDUCTION IN THE INTERCLASS SUBSIDY REVENUES IN THIS PROCEEDING?

A. The Company's goal is to move toward earning the same rate of return on all customer classes, based on equitable considerations and based upon the principle of cost causation. Attachment DLS-1 is a summary of the Cost of Service results prior to the interclass subsidy revenue calculation and development of proposed revenues. In reviewing the present rates of return shown on DLS-1, page 1, there are fairly large differences among the rate classes.

The Company is proposing to eliminate 100% of interclass subsidies in this proceeding. As a general tenet of ratemaking, all classes of customers should, to the extent practicable, pay the cost of providing service to that class. The Company's proposal to eliminate 100% of the interclass subsidies provides each class with an accurate price signal and restores the basic ratemaking principles of cost causation. Not eliminating all interclass subsidies will only serve to perpetuate, or even worsen the problem as changes in sales among classes could exaggerate the interclass subsidy situation.

Q. WHERE CAN THE VARIOUS ELEMENTS OF THE COST OF SERVICE STUDY BE FOUND?

A. A summary of each item is listed on Schedule 1 of the cost of service study.

Schedules 2, 3, 4 and 5 contain detailed information on Rate Base; Schedule 6, Operation and Maintenance expenses; Schedule 7, Depreciation; Schedule 8, Other Taxes; Schedules 9 and 12 Federal and State Income Tax; Schedule 10, the Cost of Service Computation; Schedule 11, Capitalization Dollars, Rate of Return, Revenue and Income Tax Rates; and Schedule 13, Allocation Factors.

Q WHERE ARE THE REVENUE IMPACTS OF THE BASE RATE INCREASE OF $17.5 MILLION FOUND?

A Attachment DLS-1, page 2 provides the results of the Company's proposed base revenue increase. This attachment also supports the Company's proposed 100% reduction of the revenue interclass subsidies that currently exist.

Q. HOW WERE THE RESULTS OF YOUR COST OF SERVICE STUDIES USED IN THIS PROCEEDING?

A. I provided the results of the fully allocated cost of service study by rate class and function to Duke Energy Kentucky Witness, James E. Ziolkowski, to develop the proposed revenue distribution and rate design for this proceeding.

IV. CONCLUSION

Q. WERE SCHEDULES B-7, B-7.1, B-7.2, D-3, D-4 and D-5, FR 10(9)V-1 THROUGH FR 10(9)V-5, WORKPAPER WPFR 10(9)v-6, AND ATTACHMENT DLS-1 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

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

A. Yes.

VERIFICATION

State of Ohio)
) SS:
County of Hamilton)

The undersigned, Donald L. Storck, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Donald L. Storck

Donald L. Storck, Affiant

Subscribed and sworn to before me by Donald L. Storck on this 11th day of June, 2009.

Patty A. Selm

NOTARY PUBLIC

My Commission Expires: PATTY A. SELM
Notary Public, State of Ohio
My Commission Expires 09-15-2014

DUKE ENERGY KENTUCKY
COMPUTATION OF THE RATE INCREASE AMOUNT BY RATE CLASS
INTERCLASS SUBSIDY CALCULATION
TWELVE MONTHS ENDING JANUARY 31, 2011
GAS CASE NO: 2009-00202

Line No.	Rate Class	Capitalization (A)	Present Revenues (B)	Present Net Operating Income (C)	Present ROR (D)	Gross Revenues At Average ROR (E)	**Interclass Subsidization** Overcollected (Undercollected)* (F)	**Interclass Subsidization** Times **100%** (G)	Rate Increase Allocated on Capitalization (H)	Proposed Revenues Reflecting Elimination of **100% of Interclass Subsidies** (I)	Proposed Percent Increase (J)	Proposed Increase Reflecting Elimination of **100% of Interclass Subsidization** (L)	ROR At Proposed Rates (K)	Revenue Distribution (M)
		Schedule 1 COS	Schedule 1 COS	Schedule 1 COS	(C) / (A)	(((A) * (A) Line 8) - (C)) / (A) Line 11) + (B)	(B) - (E)	(F) * 100%	((A) / (A) Line 6)) * (H) Line 6)	(H)-(G)+(B)	((I)-(B))/(B)	(H) - (G)	(((L)*(Line 11)+(C)))/(A)	(I)/(I) Line 6
1	Rate RS	181,043,179	80,575,805	4,837,972	2.6723000%	82,905,852	(2,330,047)	(2,330,047)	12,481,528	95,387,380	18.38220%	14,811,575	7.67100%	67.44420%
2	Rate GS	56,972,003	39,810,798	3,029,531	5.3176000%	38,077,415	1,733,383	1,733,383	3,927,779	42,005,194	5.51210%	2,194,396	7.67100%	29.70000%
3	Rate FT-L	10,802,148	2,490,892	719,655	6.6621000%	1,924,522	566,370	566,370	744,725	2,669,247	7.16030%	178,355	7.67100%	1.88730%
4	Rate IT	4,932,905	1,059,928	189,119	3.8338000%	1,029,634	30,294	30,294	340,086	1,369,720	29.22760%	309,792	7.67100%	0.96850%
5														
6	Total	253,750,235	123,937,423	8,776,277	3.4586000%	123,937,423	0	0	17,494,117	141,431,540	14.11530%	17,494,117	7.6710%	100.000%
7														
8	Avg. Present Rate of Return	3.4586000%												
9														
10														
11	Tax Complement	61.100000%	(1-composite tax rate)											

* (Undercollected) means that class is being subsidized by other classes.
Overcollected means that class is subsidizing other classes.

DUKE ENERGY KENTUCKY
COST OF SERVICE STUDY
TWELVE MONTHS ENDING JANUARY 31, 2011
GAS CASE NO: 2009-00202

	ITEM	ALLO	TOTAL GAS	RS RESIDENTIAL	GS GENERAL SERV	FT FIRM TRANS	IT INTERRUPT TRANS	TOTAL AT ISSUE
SUMMARY OF RESULTS	Schedule 1							
NET INCOME COMPUTATION								
GROSS GAS PLANT IN SERVICE	GP11		388,986,305	277,183,024	87,505,785	16,720,073	7,577,423	388,986,305
TOTAL DEPRECIATION RESERVE	DR11		(106,403,991)	(75,808,174)	(23,725,982)	(4,680,525)	(2,189,310)	(106,403,991)
TOTAL RATE BASE ADJUSTMENTS	RB71		(29,456,349)	(20,777,257)	(6,947,127)	(1,264,357)	(467,608)	(29,456,349)
TOTAL RATE BASE	RB91		253,125,965	180,597,593	56,832,676	10,775,191	4,920,505	253,125,965
CAPITALIZATION ALLOC TO GAS OPER	GCAP		253,750,235	181,043,179	56,972,003	10,802,148	4,932,905	253,750,235
OPERATING EXPENSES								
TOTAL O&M EXPENSE	OM31		97,956,713	64,324,114	32,324,667	797,954	509,978	97,956,713
TOTAL DEPRECIATION EXPENSE	DE41		11,657,827	8,320,709	2,612,051	496,773	228,294	11,657,827
TOTAL OTHER TAX & MISC EXPENSE	L591		4,089,172	2,927,570	903,726	174,632	83,244	4,089,172
TOTAL OP EXP EXC INC & R TAX	OP61		113,703,712	75,572,393	35,840,444	1,469,359	821,516	113,703,712
NET FED INCOME TAX EXP ALLOWABLE	I879		7,848,516	5,601,847	1,758,134	335,573	152,961	7,848,515
NET STATE INCOME TAX EXP ALLOWABLE	J979		1,447,800	1,033,455	324,185	61,900	28,260	1,447,800
AFUDC OFFSET	LO33	CW29	(289,745)	(206,391)	(65,216)	(12,534)	(5,604)	(289,745)
TOTAL OPERATING EXPENSE	OPEX		122,710,283	82,001,304	37,857,547	1,854,298	997,133	122,710,282
RETURN ON CAPITALIZATION	RC51		19,465,181	13,887,823	4,370,322	828,633	378,403	19,465,181
TOTAL OTHER OPERATING REVENUES	QO27		(743,924)	(501,779)	(222,651)	(13,679)	(5,815)	(743,924)
TOTAL GAS COST OF SERVICE	CS05		141,431,540	95,387,348	42,005,218	2,669,252	1,369,721	141,431,539
PROPOSED REVENUES	R602		123,937,423	80,575,805	39,810,798	2,490,892	1,059,928	123,937,423
EXCESS REVENUES	XREV		(17,494,117)	(14,811,543)	(2,194,420)	(178,360)	(309,793)	(17,494,116)
TOTAL RETURN EARNED	RETE		8,776,276	4,837,972	3,029,531	719,655	189,119	8,776,277
RATE OF RETURN EARNED ON CAP	RORE		0.034590	0.026720	0.053180	0.066620	0.038338	0.03459
TOTAL RATE OF RETURN ALLOWABLE	RORA		0.076710	0.076710	0.076710	0.076710	0.076710	0.07671
RETURN EARNED ON COMMON EQUITY	REOE		0.02560	0.00980	0.06280	0.08978	0.03310	0.02560
ALLOWED RETURN ON COMMON EQUITY	AROE		0.11000	0.11000	0.11000	0.11000	0.11000	0.11000
PRESENT REVENUES	R600		123,937,423	80,575,805	39,810,798	2,490,892	1,059,928	123,937,423
REVENUE INCREASE JUSTIFIED	RIJD		17,494,117	14,811,543	2,194,420	178,360	309,793	17,494,116
PER UNIT PRES REV	RIJP		0.14115	0.18382	0.05512	0.07160	0.29228	0.14115
REVENUE INCREASE REQUESTED	RIRD		0	0	0	0	0	0
PER UNIT PRES REV	RIRP		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN ADJUSTMENT	)	
OF GAS RATES OF	)	CASE NO. 2009-00202
DUKE ENERGY KENTUCKY, INC.	)	

DIRECT TESTIMONY OF

WILLIAM DON WATHEN JR.

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

July 1, 2009

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William Don Wathen Jr. 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, Inc., an affiliate service company of Duke Energy Kentucky, Inc (Duke Energy Kentucky or the Company) as Director, Rates.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I received Bachelor Degrees in Business and Chemical Engineering, and a Master of Business Administration Degree, all from the University of Kentucky. After completing graduate studies, I was employed by Kentucky Utilities Company as a planning analyst. In 1989, I began employment with the Indiana Utility Regulatory Commission as a senior engineer. From 1992 until mid-1998, I was employed by SVBK Consulting Group, where I held several positions as a consultant focusing principally on utility rate matters. I was hired by Cinergy Services, Inc., in 1998, as an Economic and Financial Specialist in the Budgets and Forecasts Department. In 1999, I was promoted to the position of Manager, Financial Forecasts. In August 2003, I was named to my current position as Director of Revenue Requirements in the Rates Department.

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

A. Yes. I previously testified in a number of cases before this and other regulatory commissions.

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

A. I address certain matters raised by the Kentucky Public Service Commission in the Company's last general gas rate case. I also sponsor Filing Requirement 10(1)(b)(1) and FR 10(2) in this proceeding, and I support the reasonableness of the Company's base rate increase request. Finally, I discuss the Company's proposal to implement a new recovery mechanism for its uncollectible expense and its proposal to implement a decoupling mechanism in the form of a modified straight fixed-variable rate design for the non-commodity service.

II. <u>REASONS FOR RATE INCREASE</u>

Q. WHEN WERE DUKE ENERGY KENTUCKY'S PRESENT GAS RATES APPROVED BY THIS COMMISSION?

A. Duke Energy Kentucky's current gas rates were approved by this Commission pursuant to its Order dated December 22, 2005, in Case No. 2005-00042. The test period in that proceeding was the forecasted twelve months ended September 30, 2006.

Q. WHAT ARE THE PRIMARY REASONS FOR DUKE ENERGY KENTUCKY'S REQUESTED RATE INCREASE IN THIS PROCEEDING?

A. Although the Company has been able to control its expenses reasonably well since the time of the last rate case, there has been a significant increase in net plant primarily due to the continuation of the accelerated main replacement program

(AMRP). As Duke Energy Kentucky witness Gary J. Hebbeler discusses in his direct testimony, the AMRP has produced and will continue to produce significant benefits for the Company and for customers. Because of the significant increase in net plant associated with the AMRP, Duke Energy Kentucky's gas business is projected to earn a 3.48% return on capitalization (3.49% on rate base) during the forecasted test period ending January 31, 2011. This return is below the 8.102% return on capitalization authorized by this Commission in Case No. 2005-00042, and is below the 7.671% return on capitalization proposed in this proceeding. In order to earn a fair return, Duke Energy Kentucky's retail rates must be increased by approximately $17.5 million to satisfy a total revenue requirement of approximately $142.2 million (including the projected cost of gas).

Q. DESCRIBE THE IMPACT THE AMRP HAS HAD ON NET PLANT SINCE THE TIME OF THE LAST GAS DISTRIBUTION RATE CASE.

A. The rate base established in Duke Energy Kentucky's last general gas rate case was as of September 30, 2006. Duke Energy Kentucky uses a forecasted test period in the present case, with rate base set on the 13-month average as of January 31, 2011. During this period from September 30, 2006, through January 31, 2011, Duke Energy Kentucky's gas distribution gross plant is projected to increase by over $112 million or 48%. AMRP accounts for most of that amount.

Q. IS THE COMPANY'S AMRP THE PRIMARY DRIVER FOR THE PROPOSED RATE INCREASE?

A. Yes. The impact on the gas distribution revenue requirement from the $112 million in additional gross plant added since the last rate case accounts for $16.9

million of the total $17.5 million overall increase. The added plant results in additional revenue requirements to cover the return, and related income taxes, required on the added plant plus additional depreciation expense and additional property tax expense.

Q. ARE THERE OTHER REASONS FOR THE DEFICIENCY?

A. Yes. The other major factor contributing to Duke Energy Kentucky needing to raise its base distribution rates is the impact of a persistent decline in consumption per customer. Energy efficiency and customer response to high prices for natural gas commodity has had a profound effect on per customer consumption in recent years. Because the Company's rate design is such that most of its revenue is dependent on volumetric sales, declines in sales, for whatever reason, will impair its ability to recover its costs of service. As I will discuss later in my testimony, the Company is making a proposal in its application, to address this issue by modifying its rate design to shift a larger portion of recovery of base revenue from volumetric charges to fixed charges to better reflect the fundamental nature of the gas distribution service being provided by Duke Energy Kentucky.

Q. HAS THE COMPANY SEEN SIGNIFICANT INCREASES IN ITS OPERATING AND MAINTENANCE EXPENSES SINCE THE TIME OF THE PRIOR RATE CASE?

A. Not at all. The forecasted test year operation and maintenance (O&M) expenses, excluding fuel, in the current case are nearly unchanged when compared to the test year in the prior case. Considering a period of more than four years will have passed between the two test periods, it is noteworthy that the Company has been able to keep its O&M expenses flat over the period.

The ability to keep costs from increasing over the period owes to the Company's intense focus on cost control, benefits derived from the merger between Duke Energy Corp. and Cinergy Corp., and reduction in maintenance expenses derived from the Company's AMRP.

Q. HAS DUKE ENERGY KENTUCKY EXPERIENCED ANY OTHER SIGNIFICANT CHANGES IN ITS COSTS SINCE ITS LAST RATE INCREASE?

A. Yes. Duke Energy Kentucky has been proactive in controlling O&M expenses and has successfully controlled its costs through a variety of initiatives, including the 2006 merger of Duke Energy and Cinergy.

The Company has also aggressively managed its financing costs, reducing its cost of long-term debt from 5.926% at September 30, 2006, in Case No. 2005-00042, to 5.707% at December 31, 2007, in Case No. 2006-00172. The financing costs are projected to be further reduced to approximately 4.657% for the forecasted test period, as supported by Company witness Stephen G. De May.

Q. IS THE COST OF GAS COMMODITY A COMPONENT OF THE RATE INCREASE REQUESTED HEREIN?

A. No. Gas commodity costs are passed through to Duke Energy Kentucky's customers at cost, with no profit or loss to Duke Energy Kentucky. The rate increase reflected in this filing does not include any incremental increases for the natural gas commodity.

Q. IS THE COMPANY PROPOSING ANY NEW RECOVERY FOR THE COMMODITY COST OF GAS IN THIS PROCEEDING?

A. Generally, the answer is no. Gas commodity costs are recovered through the gas cost adjustment (GCA) mechanism, which is adjusted on a monthly basis; therefore, the issue is outside the scope of this proceeding. As I previously mentioned, gas commodity costs are passed through to Duke Energy Kentucky's customers at cost, with no profit or loss to Duke Energy Kentucky. However, the Company is proposing to shift recovery of a portion of its uncollectible expense and recovery of carrying costs on its gas in storage from base rates to the GCA. I will discuss this in more detail later in my testimony.

III. COMPLIANCE WITH COMMISSION DIRECTIVES

Q. ARE YOU FAMILIAR WITH THE DIRECTIVES SET FORTH IN THE COMMISSION'S ORDER DATED DECEMBER 22, 2005, IN CASE NO. 2005-00042?

A. Yes. The Commission's Order, dated December 22, 2005, approved the Company's current retail gas rates. The Order also included approval of the Company's proposal to install, own, and maintain all new service lines and approval of updated depreciation rates for gas utility plant.

As I will discuss in greater detail below, the Order also approved the continuation of the Company's Rider AMRP and required Duke Energy Kentucky to file its next general rate case in 2011 to "roll-n the AMRP Rider into base rates."

Q. IF THE COMMISSION'S ORDER REQUIRED DUKE ENERGY KENTUCKY TO FILE ITS NEXT GENERAL RATE CASE IN 2011, WHY IS THE COMPANY SUBMITTING A REQUEST FOR A GENERAL RATE INCREASE IN 2009?

A. The legality of the AMRP Rider has been the subject of considerable debate since its inception in 2002. On or about August 1, 2007, the Franklin Circuit Court entered its Opinion and Order reversing the Commission's approval of the Company's Rider AMRP. Most recently, on or about November 7, 2008, the Kentucky Court of Appeals affirmed the Franklin Circuit Court in part and reversed the Franklin Circuit Court in part, finding that "*prior to the enactment of KRS 278.509, the PSC had no authority to approve the AMRP Riders.*" The Appellate Court went on to say that "*the orders of the PSC approving the AMRP Riders after the statute's enactment are valid.*" The validity of the Commission's authority to approve the Rider AMRP prior to 2005 is the subject of a Motion for Discretionary Review currently pending before the Kentucky Supreme Court.

The Company filed an Application to re-activate it Rider AMRP in early 2008 to begin recovering incremental costs associated with the AMRP over the amount that was included in base rates as a result of the prior case, Case No. 2005-00042. However, by Order dated April 17, 2008, in Case No. 2008-114, the Commission declined to rule on the Company's Application. As a result, the Company has not had an active AMRP Rider since 2005. Given the long and still pending Appeal of the Rider AMRP, and the Franklin Circuit Court's 2007 decision just recently being reversed in part, the Company's Rider AMRP remains inactive.

A plain reading of the Commission's Order in Case No. 2005-00042 makes it clear that the filing date of the next rate case assumed that Duke Energy Kentucky was recovering its revenue requirement for the AMRP via the AMRP Rider. The intent of the Commission's Order was clear that the AMRP should become part of the Company's base rates upon completion of the program. Indeed, the Commission's Order itself stated that *"based upon the assumption that the AMRP is completed by 2010, [Duke Energy Kentucky] should synchronize the filing of a general gas rate case to coincide with the termination of the AMRP Rider."* Insofar as the AMRP Rider has not been reactivated since before the last rate case, a 2011 filing date is no longer relevant. Nonetheless, the intent and need to "roll" the AMPR investment into Duke Energy Kentucky's base rates remains.

As described in the direct testimony of Mr. Hebbeler, the AMRP initiative is expected to be complete some time during 2010, the forecasted test period in this case. Given the timing of the AMRP conclusion and the forecasted test year in this case, the Company will have no need to request AMRP cost recovery via a rider in the future if the investment is "rolled" into base rates as part of this proceeding. The result of this current rate proceeding is that all AMRP revenue requirements will be fully reflected in base rates consistent with the Commonwealth of Kentucky's statutes, the intent of the Commission's prior Order in Case No. 2005-00042, and regulations regarding utility cost recovery.

IV. MERGER COMMITMENTS IN CASE NO. 2005-00228

Q. ARE YOU FAMILIAR WITH THE MERGER COMMITMENTS THAT THE COMPANY MADE, AND THE COMMISSION APPROVED, IN CASE NO. 2005-00228 (MERGER ORDER) RELATED TO FUTURE RATEMAKING PROCEEDINGS?

A. Yes.

Q. PLEASE EXPLAIN THESE COMMITMENTS AND EXPLAIN HOW THE COMPANY HAS HONORED THESE COMMITMENTS.

A. I will list below each merger commitment related to future ratemaking proceedings, and discuss how the Company has complied with each one:

- The Stipulation approved in the Merger Order, among other things, provided for certain rate credits, to be terminated upon the effective date of new rates in the Company's next base rate case, excluding any case resulting in new rates prior to January 1, 2008. Following the statutory mandated suspension period, the proposed rates in this case would take effect on February 1, 2010. Since the proposed rates will be effective after January 1, 2008, the merger credits will be terminated. However, insofar as merger savings have been achieved, as reflected in the Company's relatively flat O&M since 2005, those savings will continue to be reflected in base rates.

The Stipulation contains an Attachment 2 listing 46 separate merger commitments. Of the commitments that are relevant to this proceeding:,

- Merger commitments #3 and #4 relate to push-down accounting. Merger commitment #3 states that the payment for Cinergy's stock shall be excluded from Duke Energy Kentucky's books for retail ratemaking purposes. Merger commitment #4 states that any such acquisition premium would be excluded from retail ratemaking. The Company subsequently determined that it would end its voluntary reporting to the U.S. Securities and Exchange Commission, such that it would not be subject to push-down accounting. Duke Energy Kentucky did not reflect any such payment on its books; therefore, its proposed rates do not reflect any such payment or acquisition premium;
- Merger commitment #5 states that the Company would exclude change in control payments for retail ratemaking purposes. No change in control payments were allocated to Duke Energy Kentucky; therefore, its proposed rates do not reflect any change in control payments;
- Merger commitment #14 recognizes the Commission's continuing jurisdiction, for retail ratemaking purposes, over Duke Energy Kentucky's capital structure, financing, and cost of capital. The Company continues to recognize that the Commission has such jurisdiction;
- Merger commitment #15 states that the merger will have no adverse impact on the base rates or the operation of the fuel adjustment clause, gas supply clause, and demand side management clause of Duke Energy Kentucky. The Company's proposed rates reflect the benefits of merger

savings allocated to Duke Energy Kentucky; so, the Company has met this merger commitment;

- Merger commitment #16 states that Duke Energy Kentucky will not seek a higher rate of return on equity than would have been sought if the merger had not occurred. As supported by Dr. Morin, the Company's proposed cost of equity is not higher than it would have been absent the merger, so the Company has satisfied this merger commitment; and
- Merger commitment #17 states that the accounting and ratemaking treatment of the Company's excess deferred income taxes shall not be affected by the merger. The Company was not required to apply push-down accounting; therefore, the merger had no impact on the Company's excess deferred income taxes. Accordingly, the Company has honored this merger commitment.

V. OTHER ISSUES

A. ACCELERATED MAIN REPLACEMENT PROGRAM

Q. IN ITS PRIOR GAS DISTRIBUTION RATE CASES, DUKE ENERGY KENTUCKY PROPOSED A RIDER TO RECOVER ITS INVESTMENT IN THE COMMISSION-APPROVED ACCELERATED MAIN REPLACEMENT PROGRAM. IS THE COMPANY PROPOSING SUCH A RIDER IN THIS CASE?

A. No. When the Company initially proposed the AMRP in its 2001 gas distribution rate case, it anticipated that the program would take about 10 years to complete. As Company witness Mr. Hebbeler explains in his testimony, the AMRP is expected to be complete sometime in 2010. Consequently, there is no longer a need to continue Rider AMRP and the Company is proposing to eliminate this rider from its tariffs and roll all of the incremental AMRP plant investment into base rates.

B. RATE DESIGN

Q. DOES THE COMPANY HAVE A PROPOSAL TO MITIGATE THE IMPACT OF VOLUMETRIC DECLINES IN SALES?

A. Yes. As described in more detail by Company witness James E. Ziolkowski, a decoupling mechanism in the form of a modified straight-fixed variable (SFV) rate design can mitigate the impact of volumetric declines in sales due to energy efficiency or customer response to commodity pricing. Insofar as the majority of the non-commodity cost of providing gas distribution service is fixed, a modified SFV rate design is a reasonable and effective way to 'decouple' the Company's ability to recover its cost of service from the amount of gas it sells.

C. UNCOLLECTIBLE EXPENSE RECOVERY

Q. WHAT IS BAD DEBT EXPENSE?

A. Bad debt is the portion of an account receivable that, in a company's judgment, will not be collected. From an accounting perspective, bad debt is considered an expense and is accrued periodically based upon the company's experience in collecting its receivables. In the context of this natural gas base rate case, bad debt expense can be attributed to two sources that coincidentally comprise both portions of a customer's bill. Specifically, these two portions are the natural gas commodity itself and the utility's costs to deliver the natural gas to the customer's meter.

Q. HOW DOES THE COMPANY TRADITIONALLY RECOVER ITS BAD DEBT EXPENSE?

A. Currently, bad debt expense is included in the Company's overall revenue requirement which gets converted into the Company's retail base rates. Typically, discrete components of revenue requirements, such as bad debt expense, are not unbundled (*i.e.*, shown separately on customers' bills); instead, such expenses are combined into an overall revenue requirement.

Q. WHAT TYPES OF COSTS ARE TREATED DIFFERENTLY FOR RATEMAKING?

A. Typically, expenses that are of sufficient magnitude, volatile, and outside the utility's control are unbundled from general base rates. An obvious example of a cost that exhibits these qualities is the commodity cost of gas which currently accounts for more than half of a customer's bill. The cost of gas, however, is not the only type of cost that meets the criteria. Duke Energy Kentucky submits that bad debt is an expense that meets the criteria, particularly the portion of bad debt attributable to the commodity price. Notwithstanding the Company's efforts to receive payment from customers following appropriate rules for disconnection for non-payment on accounts, it is an unavoidable fact that some accounts remain uncollectible and result in bad debt expense being accrued. Unfortunately, the current economic climate has exacerbated an already difficult situation and is resulting in an increase in the occurrence and magnitude of bad debt expense.

In addition to the overall economy's impact on bad debt expense, the inherent volatility of the price of the natural gas commodity also has a significant effect on bad debt expense. The combined impact of these factors clearly puts bad debt expense outside the control of the utility, particularly as it relates to the commodity portion of overall gas rates.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL FOR RECOVERY OF BAD DEBT EXPENSE?

A. Duke Energy Kentucky proposes to modify its GCA filings to include a periodic update for bad debt expense associated with the commodity portion of customers' bills. Arguably, bad debt expense related to the base portion of customers' bills is volatile and somewhat outside of the Company's control as well. However, the Company is proposing to continue base rate recovery of this portion of bad debt expense at the pro rata forecasted test year level. Duke Energy Kentucky witness Robert M. Parsons provides the details of the Company's base and forecasted test year bad debt expense and illustrates the calculations necessary to move the commodity portion of bad debt expense from base rates to the GCA.

Q. IS THERE ANY OTHER REASON FOR SHIFTING COST RECOVERY OF THE COMMODITY PORTION OF BAD DEBT EXPENSE TO THE GCA?

A. Yes. Duke Energy Kentucky's proposal is reasonable, prudent, and in the public interest for two reasons. First and most importantly, the Company's proposal appropriately aligns the expense with recovery in a manner that is beneficial to rate payers. As I stated previously, Duke Energy Kentucky currently includes bad debt expense as part of its base rates. The actual level of bad debt expense may or may not reflect the level of expense embedded in base rates. Duke Energy Kentucky, at any given point, may be over- or under-recovering the bad debt expense. However, including the commodity portion of the bad debt expense as part of the monthly GCA adjustment, will allow the Company to timely recover a portion of its actual bad debt expense that is directly related to the cost of the natural gas commodity, while ensuring that customers are not overpaying. Second, the Company's proposal is reasonable and prudent from a public policy standpoint. Although Duke Energy Kentucky does not have customer choice, the Company does have a firm transportation[1] rate (Rate FT-L) for large natural gas customers, affording them the opportunity to purchase natural gas directly from suppliers while paying Duke Energy Kentucky for the delivery and administration. Nonetheless, expanded customer choice is a circumstance that could materialize. If that happens, there will be a group of customers paying Duke Energy Kentucky for commodity service and a group that takes gas from an alternative supplier.

If <u>all</u> projected bad debt expense is included in base rates, then customers who switch to alternative suppliers could potentially end up paying more than their share for bad debt expense. A customer who switches to an alternative supplier will still pay Duke Energy Kentucky the full amount of base rates (*i.e.*, non-commodity rates), which includes a component for bad debt expense. The alternative supplier must factor in some level of bad debt in its price for the

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[1] The term "transportation customers" refers to the nature of service being provided to these customers. Duke Energy Kentucky sells no gas commodity to these customers but doesprovide the transportation of such gas through its system.

commodity since some fraction of customers will not pay their bills. To the extent that the price they pay the supplier includes some provision for bad debt and their base rates also include a provision for bad debt on the commodity portion of gas, these customers will effectively be paying twice for bad debt expense.

Incorporating the commodity portion of the bad debt expense into the GCA will ensure that customers not taking commodity gas service from Duke Energy Kentucky will not pay for bad debt expense related to commodity service. It is a sensible and reasonable solution balancing the interests of all stakeholders.

D. CARRYING COST ON GAS IN STORAGE

Q. PLEASE DESCRIBE HOW THE COMPANY CURRENTLY RECOVERS CARRYING COSTS ON ITS INVESTMENT IN GAS STORED UNDERGROUND.

A. Historically, a utility's investment in gas stored underground is treated as one component of working capital that is included in the Company's overall rate base. The magnitude of the investment is established as part of a general rate case. Since any component of rate base impacts the rate base ratio used to allocate total company capitalization to gas operations, including gas stored underground in rate base essentially creates a revenue requirement based on the utility's overall rate of return.

As an example, assuming the Company earned a return on rate base rather than capitalization, an investment of $10 million in gas stored underground in its test period rate base and a 12% overall pre-tax weighted average cost of capital would result in $1.2 million ($10 million * 12%) being included in the overall revenue requirement.

Q. IS THIS A REASONABLE METHOD OF RECOVERY?

A. It is a common method and, when natural gas prices are relatively stable, it is reasonable. However, those who have followed the price of natural gas in the last ten years are unlikely to use the term 'stable' when describing its history over that time.

Q. IS THERE ANY CONCERN WITH LEAVING RECOVERY OF CARRYING COSTS FOR GAS IN STORAGE IN THE BASE RATE RECOVERY?

A. There are two concerns with the existing method of recovery. First, the magnitude of the investment in gas stored underground can change significantly over a relatively short time. Consider my previous example where base rates included recovery of a carrying cost on $10 million in gas in storage. If prices for natural gas decline sharply, such that the gas in storage is only $5 million, then customers are paying a fixed level in base rates, twice the company's true cost of carrying that investment. Similarly, if gas prices rise sharply, the Company could be significantly under-recovering its costs.

The second concern is that the cost of the commodity should be linked more closely with the recovery of commodity costs. In other words, since the gas held in storage will ultimately be recovered via the Company's GCA then it follows that the carrying cost on this gas commodity should be recovered in the same manner.

Q. WHAT IS THE COMPANY'S PROPOSAL FOR RECOVERING CARRYING COSTS ON GAS IN STORAGE?

A. The Company is proposing to modify the GCA calculation to include recovery of carrying costs on gas in storage. As part of this proposal, the Company is excluding the same investment from its proposed forecasted test year rate base. Mr. Parsons includes the detailed calculations associated with this proposal in his direct testimony.

Q. WHAT RETURN WOULD BE USED FOR CALCULATING THE CARRYING COSTS?

A. Because the investment would be earning the overall pre-tax weighted-average cost of capital if left in the rate base, this is the appropriate return to use when calculating the return requirement in the GCA.

Q. IS THIS A REASONABLE APPROACH TO RECOVERING THE CARRYING COST ON GAS IN STORAGE?

A. Yes. Duke Energy Kentucky's affiliate company, Duke Energy Ohio, Inc. and at least one other utility use a similar methodology in Ohio. It is a reasonable and sensible approach. It fairly balances the interests of all stakeholders and significantly enhances the regulatory principle of marrying cost causation with cost recovery.

VI. <u>FILING REQUIREMENTS SPONSORED BY WITNESS</u>

Q. PLEASE DESCRIBE FR 10(1)(b)(1).

A. FR 10(1)(b)(1) is Duke Energy Kentucky's statement of the reasons for the proposed increase.

Q. PLEASE DESCRIBE FR 10(2).

A. FR 10(2) is a statement certifying that the Company provided four weeks' notice of its rate application, as required by the Commission's rules.

VII. CONCLUSION

Q. HAVE YOU REVIEWED DUKE ENERGY KENTUCKY'S FILING IN THIS PROCEEDING?

A. Yes, I have. I reviewed the application and supporting schedules, and the testimony and attachments of all witnesses. I believe that the costs of service are properly allocated to customer classes, and the rate design is equitable.

Q. DO YOU HAVE AN OPINION REGARDING WHETHER DUKE ENERGY KENTUCKY'S RATE REQUEST IS REASONABLE?

A. Yes.

Q. PLEASE STATE YOUR OPINION.

A. Duke Energy Kentucky's rate request is fair and reasonable. The date certain in Duke Energy Kentucky's last rate case was September 30, 2006, and the forecasted test period in this case extends through January 31, 2011. Duke Energy Kentucky has made, and plans to continue to make, significant capital investments in its gas system. As stated previously, a reasonable return of and on these significant capital investments is the primary driver of this base rate case.

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

A. Yes.

VERIFICATION

State of Ohio)
)
County of Hamilton)

The undersigned, William Don Wathen Jr. being duly sworn, deposes and says that he is the Director, Rates for Duke Energy Business Services, that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Don Wathen
William Don Wathen Jr, Affiant

Subscribed and sworn to before me by William Don Wathen Jr. on this 17th day of June 2009.

Patty A. Selm
NOTARY PUBLIC

My Commission Expires:

PATTY A. SELM
Notary Public, State of Ohio
My Commission Expires 09-15-2014

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN ADJUSTMENT	)	
OF GAS RATES OF	)	CASE NO. 2009-00202
DUKE ENERGY KENTUCKY, INC.	)	

DIRECT TESTIMONY OF

JAMES E. ZIOLKOWSKI

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

July 1, 2009

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TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James E. Ziolkowski. My business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

Q. WHAT IS YOUR CURRENT POSITION?

A. I am employed by Duke Energy Business Services, Inc., an affiliate service company of Duke Energy Kentucky, Inc (Duke Energy Kentucky or the Company), as Rates Manager.

Q. WILL YOU PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS

A. I received a Bachelor of Science degree in Mechanical Engineering from the U.S. Naval Academy in 1979, and a Master of Business Administration degree from Miami University in 1988. I am also a licensed Professional Engineer in the state of Ohio.

After graduating from the Naval Academy, I attended the Naval Nuclear Power School and other follow-on schools. I served as a nuclear-trained officer on various ships in the U.S. Navy through 1986. From 1988 through 1990, I worked for Mobil Oil Corporation as a Marine Marketing Representative in the New York City area.

I joined The Cincinnati Gas & Electric Company (CG&E) in 1990 as a Product Applications Engineer, in which capacity I designed and managed some of CG&E's demand side management programs including Energy Audits and Interruptible Rates. From 1996 until 1998, I was an Account Engineer, and worked with large consumers to resolve various service-related issues, particularly in the areas of billing, metering, and demand management. In 1998, I joined Cinergy Services, Inc.'s Rate Department, where I focus on rate design and tariff administration. I was appointed to my current position in January 2008.

Q. PLEASE SUMMARIZE YOUR DUTIES AS RATES MANAGER.

A. As Rate Manager, I address primarily rate design, tariff, billing, and revenue reporting issues in Ohio and Kentucky. I also prepare filings to modify charges and terms in Duke Energy Kentucky's and Duke Energy Ohio, Inc.'s (Duke Energy Ohio) retail tariffs, and develop rates for new services. During major rate cases, I help with the design of the new base rates. Additionally, I frequently work with Duke Energy Ohio's and Duke Energy Kentucky's consumer contact and billing personnel to answer rate-related questions, and to apply the retail tariffs to specific situations. Occasionally, I meet with customers and Company representatives to explain rates or provide rate training. I also prepare reports that are required by regulatory authorities.

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

A. I am responsible for Duke Energy Kentucky's proposed gas rate design and tariffs. My testimony will demonstrate that the rates that Duke Energy Kentucky is proposing 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. Additionally, I sponsor Schedules, L, L-1, L-2.1, L-2.2, M, M-2.1

through M-2.3 and N. The "L" series of schedules satisfy Filing Requirements (FR) 10(10)(l), 10(1)(b)(7), and 10(1)(b)(8). The "M" series of schedules satisfies FR 10(10)(m), and the "N" schedule satisfies FR 10(10)(n)

II. SCHEDULES 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.

A. Schedule L-2 contains Duke Energy Kentucky's current and proposed rate schedules, showing the revisions that Duke Energy Kentucky proposes in this filing in a side by side format. 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 forecasted period (12 months ending January 31, 2011) revenues at present and proposed rates. Schedule M shows that Duke Energy Kentucky is proposing an 18.38% increase in the Residential (RS) rate class, a 5.51% increase in the General Service (GS) rate class, a 7.16% increase in the Firm Transportation – Large (FT-L) class, and a 29.23% increase in Interruptible Transportation Service (IT) rate class.

These average increases are based upon base rates only and an assumed gas cost of $7.436 per MCF. The Company also filed a Schedule M that reflects base period (12 months ending September 30, 2009) billing determinants and revenues.

Q. PLEASE DESCRIBE SCHEDULE M-2.1.

A. Schedule M-2.1 shows actual base revenue dollars and the percentage distribution among the various rate classes as well as total revenue dollars broken down the same way. Schedule M-2.1 also shows the actual base revenue average rates per Mcf for each rate class. The Company prepared Schedule M-2.1 for both the forecast period and the base period.

Q. PLEASE DESCRIBE SCHEDULES M-2.2 AND M- 2.3.

A. Schedule M-2.2, page 1, shows, in summary form, the forecasted period total bills, throughput volumes, base revenues under current rates, expected gas cost revenues, current total revenues, and proposed base revenue increases, all broken down by rate and revenue class. Note that the billing determinants used on these schedules represent normalized sales for the twelve months ended January 31, 2011. Schedule M-2.2, pages 2-7, show a detailed calculation of forecasted period numbers, by rate and revenue class, as summarized on Schedule M-2.2. Schedule M-2.3 is almost identical to Schedule M-2.2, except that it shows the revenue summary and detailed data calculated at the rates proposed in this case. The Company also filed Schedules M-2.2 and M-2.3 that reflect base period billing determinants and revenues.

Q. PLEASE DESCRIBE SCHEDULE N.

A. Schedule N shows monthly bill comparisons for various usage levels under each of Duke Energy Kentucky's primary tariff schedules, Rates RS, GS, FT-L and IT. This schedule allows comparisons and assessment of how these changes impact individual customers. These comparisons were produced using an assumed gas cost rate of $7.436 per Mcf, as well as the Rider DSM charges in effect during June 2009. The Company also filed Schedule N for the base period that includes an assume gas cost rate of $7.000 per Mcf.

III. RATE DESIGN

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 Mr. Donald L. Storck 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 100%. The results of these studies can be found in Attachment DLS-1, pages 1 and 2, sponsored by Mr. Storck.

Q. PLEASE DESCRIBE ATTACHMENT JEZ-1.

A. Attachment JEZ-1 sets forth the customer-related costs of serving residential customers under Rate RS, non-residential firm customers under Rate GS, large firm transportation commercial/industrial customers under Rate FT-L, and large interruptible transportation commercial/industrial customers under Rate IT. I obtained this information from the functional cost of service information, FR 10(9)v-2 through FR 10(9)v-5, sponsored by Mr. Storck. Attachment JEZ-1, pages

1-4 shows monthly customer-related costs of $25.11, $47.82, $305.17 and $784.74, applicable to Rates RS, GS, FT-L and IT, respectively. Attachment JEZ-1, page 5 shows the customer-related cost of FT-L and IT combined together. The combined FT-L / IT customer cost is $410.77.

In the rate design in this case, I propose a customer charge of $47.50 for Rate GS. For Rates FT-L and IT I propose to maintain the administrative charge at the current $430.00. For Rate RS, I propose a customer charge of $30.00 that recovers some costs above those justified in Attachment JEZ-1, page 1.

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 firm 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. Storck.

IV. ENHANCED COST RECOVERY (MODIFIED STRAIGHT FIXED VARIABLE) RATE DESIGN

Q. PLEASE DEFINE STRAIGHT-FIXED VARIABLE.

A. Straight-Fixed Variable is a form of decoupling. A pure straight fixed variable rate design places all of a utility's fixed cost into a fixed component of a utility customer's bill, thereby recovering only variable costs, such as cost of gas, on a variable (*e.g.*, per Mcf basis). A standard two-part tariff, in contrast, usually collects some fixed costs through a variable charge.

Q. ARE THERE ANY FEDERAL OR STATE DIRECTIVES THAT REQUIRE CONSIDERATION OF DECOUPLING?

A. Yes, on November 13, 2008, the Kentucky Public Service Commission (Commission) issued an Order in Case No. 2008-00408 to initiate an administrative proceeding to consider the requirements of the federal Energy Independence and Security Act of 2007 (EISA 2007). One of the EISA 2007 requirements relates to Section 532(b)(6), Rate Design Modification to Promote Energy Efficiency Investments – Gas Utilities. Specifically, Section 532(b)(6)(B)(i) states "…each State regulatory authority and each non-regulated utility shall consider separating fixed-cost revenue recovery from the volume of transportation or sales service provided to the customer,…" The Company's proposal in the current case to recover additional costs through the residential customer charge begins to decouple fixed-cost revenue recovery from sales volumes. In the future, as SmartGrid technologies are deployed throughout the Company's service territory, the Company might be able to design and implement innovative new rates that decouple revenues from usage and, at the same time, encourage conservation.

Q. DID DUKE ENERGY FILE TESTIMONY IN CASE NO. 2008-00408?

A. Yes, on January 9, 2009, Duke Energy filed testimony of four witnesses in that case. One of those witnesses, Mr. Jeffrey R. Bailey, testified as to the Company's opinion regarding the separation of fixed-cost revenue recovery from the volume of transportation or sales service provided to the customer. In his testimony, Mr. Bailey states that Duke Energy Kentucky is generally supportive of rate decoupling for natural gas utilities, providing of course, the methodology used is appropriate. Mr. Bailey goes on to say that one of the drawbacks of energy efficiency is that a volumetric rate design does not allow natural gas utilities an adequate opportunity to recover its based revenues due to steadily declining use per customer. The declining throughput occurs primarily because furnaces are increasingly more efficient, customers increasingly have better insulated homes and customers have responded to natural gas price increases. This creates a dilemma for utilities between advocating for further conservation measures or attaining an adequate return by selling more gas. Mr. Bailey concludes this portion of his testimony by stating that, by severing the relationship between cost recovery and customer throughput, the utility can both recoup its legitimate costs and sponsor conservation.

Q. DO YOU AGREE WITH MR. BAILEY'S TESTIMONY?

A. Yes, I do.

Q. DOES ANY OF DUKE ENERGY KENTUCKY SISTER UTILITY COMPANIES HAVE A DECOUPLING MECHANISM IMPLEMENTED?

A. Yes, Duke Energy Ohio has recently implemented a form of decoupling known as modified straight-fixed variable rate design (SFV). While the design in this case does not allow for recovery of all fixed costs in a fixed fee, it does place a greater portion of the utility's fixed costs for providing natural gas in the fixed customer charge portion of the customer's bill. The benefits of this design are that it provides the utility with a greater opportunity to recover fixed costs, thereby reducing the disincentive to promoting energy efficiency, while at the same time, levelizes customer bills. A smaller portion of the customer's bill will be impacted by fluctuations in natural gas usage during peak winter periods. The larger customer charge provides greater revenue predictability for the utility, mitigates that erosion of recovery of fixed costs due to energy efficiency, reduces bill volatility for customers, and will likely extend or lengthen the time between rate cases. Although bill levelization is not the main goal of the modified SFV rate – the goal is sales decoupling – it is a benefit to customers. The choice to implement a modified SFV gives weight to the benefits of full SFV recovery versus the impact of a significant increase in bills for low-usage customers.

Q. PLEASE EXPLAIN THE RATE DESIGN DUKE ENERGY KENTUCKY IS PROPOSING IN THIS PROCEEDING.

A. The Company proposes a rate design for all customers served under Rate RS (Residential Service) that recovers all customer-related costs and additional fixed costs through the monthly customer charge. The proposed rate simply moves a portion of the fixed costs for providing natural gas service from the volumetric rate to the fixed monthly charge, which is more consistent with the customer charge shown in Attachment JEZ-1, Page 1. This is a better rate design than Duke Energy Kentucky's existing rate design for the following reasons:

- A larger fixed distribution service charge rate reduces a utility's disincentive to promote natural gas conservation. Duke Energy Kentucky currently offers demand side management programs that promote gas conservation. Duke Energy Kentucky's recovery of fixed costs in the delivery charge makes its profitability tied to volumetric sales.

- A higher fixed distribution service charge rate that recovers more of the Company's cost of service decouples the link between profitability and volumetric sales.
- A larger fixed distribution service charge rate will reduce the impact of regulatory lag and the number of future rate cases. In a period of declining sales and increasing costs, a larger fixed distribution service charge rate allows Duke Energy Kentucky a better opportunity, but not a guarantee, to recover its fixed costs. Under traditional rates some component of fixed costs are embedded in the volumetric charge and therefore recovery is tied to customer consumption.

Q. WHY IS DUKE ENERGY KENTUCKY'S CURRENT VOLUMETRIC RATE DESIGN INADEQUATE IN TODAY'S ENVIRONMENT?

A. The current volumetric rate design doesn't allow Duke Energy Kentucky an adequate opportunity to recover its base revenues due to the steadily declining throughput per customer. The only way to ensure that Duke Energy Kentucky has the opportunity to recover the appropriate level of fixed costs from its customers is to break the link between customer usage and cost recovery. Below is a table showing average annual weather-normal residential sales for 1990-2008, which I prepared based on the average annual Mcf sales information supplied by Duke Energy Kentucky Witness, Mr. Timothy A. Phillips.

Duke Energy Kentucky Average Annual Weather-Normal Residential Gas Sales		
Year	Average Sales (Mcf)	Percent Increase/(Decrease) Over Ten Years
1990	110.53	
1991	108.25	
1992	107.13	
1993	104.80	
1994	100.92	
1995	98.14	
1996	96.96	
1997	94.49	
1998	91.41	
1999	87.89	
2000	88.83	-19.6%
2001	82.87	-23.4%
2002	81.75	-23.7%
2003	84.24	-19.6%
2004	79.46	-21.3%
2005	78.88	-19.6%
2006	71.13	-26.6%
2007	71.02	-24.8%
2008	73.89	-19.2%

As shown by the Table above, Duke Energy Kentucky has experienced a steady decline in its average gas sales. Declining throughput occurs primarily because furnaces are increasingly more efficient, customers increasingly have better insulated homes and customers have responded to natural gas price increases. This creates a dilemma for Duke Energy Kentucky between advocating further conservation measures and attaining an adequate return by selling more gas. By severing the relationship between cost recovery and customer throughput, the utility can both recoup its legitimate costs and sponsor conservation.

In my opinion, the enhanced fixed-cost recovery rate design Duke Energy Kentucky is proposing is better than its current residential rate design. It improves Duke Energy Kentucky's opportunity to recover its costs while allowing customers to achieve satisfactory payback periods for energy efficiency activities.

Q. WILL CUSTOMERS AND THE UTILITY BOTH BENEFIT FROM APPROVAL OF DUKE ENERGY KENTUCKY'S PROPOSAL?

A. Yes. The rate design for residential customers will allow the Company to recover more of its fixed costs, regardless of gas consumption levels. Residential customers will benefit from the rate design because their bills will be more level throughout the year – lower in the winter and a little higher in the summer.

Q. WILL THE PROPOSED ENHANCED COST RECOVERY (MODIFIED SFV) RATE DECREASE THE NATURAL GAS PRICE SIGNAL?

A. Yes, slightly. A higher fixed charge will not reduce the *average* customer's total annual bill. While it will reduce the volumetric portion a little, still the majority of the residential revenues will continue to be recovered through volumetric based rates, including the cost of gas. Based on the Duke Energy Kentucky's forecasted residential revenues, approximately 66% of the average residential customer's bill, including the cost of gas, will be recovered through volumetric rates.

Q. IS THIS RATE DESIGN UNREASONABLY BURDENSOME ON LOW USAGE CUSTOMERS (SOME OF WHICH ARE LOW INCOME OR ON FIXED INCOMES) OR WILL IT PRODUCE RATE SHOCK?

A. No. It is true that shifting a greater portion of cost recovery to a higher fixed rate will result in a higher rate increase for low usage customers. However, it is not necessarily the case that low usage equates to low income. A review of the Company's gas customers revealed that the low income customers actually use more energy on average than the Company's other residential gas customers. In fact, many of the gas low income customers use significantly more than the average Company gas customer. The lowest income customer may well save money with a higher fixed rate. Lastly, a higher fixed rate also offers the benefit of levelizing the customer's cost of natural gas over the year thus lowering their winter bills.

Q. DOES THIS RATE DESIGN REDUCE THE ECONOMIC PAYBACK FOR THOSE CUSTOMERS WHO HAVE UNDERTAKEN ENERGY EFFICIENCY INVESTMENTS?

A. Yes, slightly. Customers who have undertaken energy efficiency investments in the past will continue to reap the benefits of their energy efficiency investments in the future. Depending on the price of the natural gas commodity, it may even increase or accelerate the benefits of such investments. Customers who have undertaken energy efficiency investments in the past are not penalized by implementing a higher fixed rate. Based on the Duke Energy Kentucky's forecasted residential revenues, approximately 66% of the average residential customer's bill, including the cost of gas, will be recovered through volumetric rates.

Q. IS THE PROPOSED RESIDENTIAL RATE DESIGN CONSISTENT WITH THE "GRADUALISM" DOCTRINE OF RATE DESIGN?

A. Yes. Although the rate design includes an increase in the customer charge there is also a reduction in the impact of the volumetric charge on the customer bill. This proposed rate design mitigates winter "rate shock" by levelizing customers' bills throughout the year. The Company recognizes that very small users will see a large percentage increase in their monthly bills, but the dollar amount of the increase is reasonable when the historical customer charge subsidy is taken into account.

Q. WHAT IS THE IMPACT OF YOUR PROPOSED RATE DESIGN ON DUKE ENERGY KENTUCKY'S INDIVIDUAL CUSTOMER CLASSES?

A. Schedule M–2.2, Page 1, Column M shows how the proposed dollar increase will be spread to each revenue class if the rates that Duke Energy Kentucky has proposed are approved. Column O of this schedule shows those same changes as percentage increases or decreases from current revenue levels. These numbers support that Duke Energy Kentucky is making reasonable movement toward cost of service rates in this filing. Schedule N provides the best measure of the impact of the rate increase to customers served under the various rate schedules, as I previously discussed

V. TARIFFS AND SERVICE REGULATIONS

Q. IS DUKE ENERGY KENTUCKY REQUESTING APPROVAL OF ANY NEW TARIFFS IN THIS PROCEEDING?

A. Yes. Duke Energy Kentucky is proposing a new tariff in this proceeding, Sheet No. 84, Meter Pulse Service (Rate MPS). Although not a new tariff, the Company is also proposing two changes to the calculation of its Gas Cost Adjustment Rider.

Q. WHAT IS METER PULSE SERVICE (RATE MPS)?

A. Some customers, particularly larger ones, have energy management systems that enable them to track their energy usage on a real-time basis. Rate MPS is an optional program available to customers that request the Company to install gas meter pulse equipment, a meter-related service not otherwise provided by the Company. Gas meter pulse equipment connects the Company's gas meter (used for billing) to the customer's energy management system and provides an input data signal that is proportional to the amount of gas consumed during a specific time interval. Rate MPS allows for tariff recovery of expenses associated with installation, and maintenance as required, of this additional equipment outside of what is needed in order to provide normal natural gas delivery service to customers. The data gathered by customers from this equipment may enable customers to more efficiently use their natural gas.

The service provided is 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 pulse supplied does not represent rate of flow, only total volume, and should not be used for control purposes. The end-use customer is responsible for providing power and communication links to the meter pulse equipment per the Company's specifications.

Duke Energy Kentucky proposes to charge a basic one-time fee of $500 for the installation of the gas meter pulse equipment. The Company may also charge to recover certain incremental costs, such as index replacement, meter replacement if necessary or additional service calls, as outlined in the proposed tariff sheet. The customer must provide either a regulated 24 volts DC, or 120 volts AC electric supply, to an area 2' x 2', approximately 20 feet away from any gas pipeline flanges or gas pressure relief devices.

Q. PLEASE DESCRIBE CHANGES TO THE GAS COST ADJUSTMENT RIDER.

A. As explained in the testimony of Duke Energy Kentucky Witness Mr. Parsons, the Company proposes to modify the Gas Cost Adjustment Rider to allow for the recovery of commodity-related uncollectible expenses and carrying costs on gas stored underground.

Q. IS DUKE ENERGY KENTUCKY PROPOSING ANY OTHER TARIFF CHANGES IN THIS PROCEEDING?

A. Yes. Duke Energy Kentucky is proposing to eliminate Rider MSR-G (Merger Savings Credit Rider – Gas, Sheet No. 64). Rider MSR-G was to remain in effect until the effective date of new rates established by the Company's next gas base rate case provided such date is later than January 1, 2008. The Company also proposes to eliminate Rider AMRP (Accelerated Main Replacement Program Rider, Sheet No. 63). The rates in this rider are zero, and the Company does not plan to implement this rider in the future. Finally, the Company proposes to correct some inconsistent text in Rate AS (Pooling Service For Interruptible Gas Transportation, Sheet No. 55).

VI. <u>CONCLUSION</u>

Q. WERE SCHEDULES, L, L-1, L-2, M, M-2.1, M-2.2, M-2.3 AND N AND ATTACHMENT JEZ-1 PREPARED BY YOU OR UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

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

A. Yes.

VERIFICATION

State of Ohio)
)
County of Hamilton)

The undersigned, James E. Ziolkowski, being duly sworn, deposes and says that he is the Rates Manager for Duke Energy Business Services, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

James E. Ziolkowski

James E. Ziolkowski, Affiant

Subscribed and sworn to before me by James E. Ziolkowski on this 18th day of June, 2009.

Patty A. Selm

NOTARY PUBLIC

My Commission Expires:

PATTY A. SELM
Notary Public, State of Ohio
My Commission Expires [illegible]

280067

Duke Energy Kentucky, Inc.
Case No. 2009-00202
Residential Service
Customer Charge / Minimum Bill Rationale
Twelve Months Ending January 31, 2011

Line No.	Description	Amount
1	Capitalization allocated to Gas Operations	$100,853,724
2	Operating Expense	$19,288,635
3	Return at 7.671%	7,736,489
4	Operating Expense plus Return	$27,025,124
5	Less Total Other Operating Revenues	80,190
6	Customer Cost Component (Revenue Requirement)	$26,944,934
7	Total Residential Service Customers	89,420
8	Annual Revenue / Customer	$301.33
9	Monthly Revenue / Customer	$25.11

Duke Energy Kentucky, Inc.
Case No. 2009-00202
General Service
Customer Charge / Minimum Bill Rationale
Twelve Months Ending January 31, 2011

Line No.	Description	Amount
1	Capitalization allocated to Gas Operations	14,204,260
2	Operating Expense	2,957,442
3	Return at 7.671%	1,089,609
4	Operating Expense plus Return	4,047,051
5	Less Total Other Operating Revenues	14,149
6	Customer Cost Component (Revenue Requirement)	4,032,902
7	Total General Service Customers	7,028
8	Annual Revenue / Customer	573.85
9	Monthly Revenue / Customer	47.82

Duke Energy Kentucky, Inc.
Case No. 2009-00202
Firm Transportation - Large
Customer Charge / Minimum Bill Rationale
Twelve Months Ending January 31, 2011

Line No.	Description	Amount
1	Capitalization allocated to Gas Operations	784,101
2	Operating Expense	253,537
3	Return at 7.671%	60,148
4	Operating Expense plus Return	313,685
5	Less Total Other Operating Revenues	2,409
6	Customer Cost Component (Revenue Requirement)	311,276
7	Total Firm Transportation Customers	85
8	Annual Revenue / Customer	3,662.08
9	Monthly Revenue / Customer	305.17

Duke Energy Kentucky, Inc.
Case No. 2009-00202
Interruptible Transportation
Customer Charge / Minimum Bill Rationale
Twelve Months Ending January 31, 2011

Line No.	Description	Amount
1	Capitalization allocated to Gas Operations	614,084
2	Operating Expense	179,579
3	Return at 7.671%	47,106
4	Operating Expense plus Return	226,685
5	Less Total Other Operating Revenues	679
6	Customer Cost Component (Revenue Requirement)	226,006
7	Total Interruptible Transportation Customers	24
8	Annual Revenue / Customer	9,416.93
9	Monthly Revenue / Customer	784.74

Duke Energy Kentucky, Inc.
Case No. 2009-00202
Combined Firm and Interruptible Transportation
Customer Charge / Minimum Bill Rationale
Twelve Months Ending January 31, 2011

Line No.	Description	Amount
1	Capitalization allocated to Gas Operations	1,398,185
2	Operating Expense	433,116
3	Return at 7.671%	107,255
4	Operating Expense plus Return	540,371
5	Less Total Other Operating Revenues	3,088
6	Customer Cost Component (Revenue Requirement)	537,283
7	Total Interruptible Transportation Customers	109
8	Annual Revenue / Customer	4,929.20
9	Monthly Revenue / Customer	410.77