COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2019-00271

DIRECT TESTIMONY OF

PAUL L. HALSTEAD

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

January 31, 2020

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Paul L. Halstead and my business address is 400 S. Tryon Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Carolinas, LLC (DEC) as a Business Development Manager II. DEC is a subsidiary of Duke Energy Corporation (Duke Energy) which provides various services to Duke Energy Kentucky, Inc. (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy.

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

A. I have a Bachelor of Science degree from Pensacola Christian College in Pensacola, Florida; an MBA from Liberty University in Lynchburg, Virginia; and hold a CPA license issued from the State of Virginia. I have worked for Duke Energy since 2008. My career at the company began with the Accounting Department where I managed various teams related to the accounting and reporting for capital assets, depreciation studies, fossil fuels, wholesale, materials/supply inventory and FERC FORM 1s. In 2016, I transitioned to the Distributed Generation Department to focus on customer programs.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS A BUSINESS DEVELOPMENT MANAGER II.

A. I am responsible for developing renewable energy programs across Duke Energy's regulated businesses.

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. The purpose of my testimony is to adopt the testimony of Duke Energy Kentucky's witness Andrew S. Ritch supporting the Company's proposed Green Source Advantage Program and tariff that was filed in September 2019 in this proceeding. Mr. Ritch no longer works for the Company. I have read Mr. Ritch's testimony and responses to data requests. I agree with his testimony and responses.

Q. **DO YOU HEREBY ADOPT MR. RITCH'S TESTIMONY AND DATA REQUEST RESPONSES FOR PURPOSES OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. Yes.

II. CONCLUSION

Q. **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes.

VERIFICATION

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

The undersigned, Paul L Halstead, Business Development Manager II, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing rebuttal testimony and that it is true and correct to the best of his knowledge, information and belief.

Paul L Halstead

Paul L. Halstead, Affiant

Subscribed and sworn to before me by Paul L. Halstead on this 10 day of January 2020.

KIM V BEAL
Notary Public
Catawba County
NORTH CAROLINA

Kim V. Beal

NOTARY PUBLIC

My Commission Expires: October 24, 2024

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2019-00271

REBUTTAL TESTIMONY OF

CHRISTOPHER M. JACOBI

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

January 31, 2020

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christopher M. Jacobi, and my business address is 550 South Tryon Street, Charlotte, North Carolina 28202.

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

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

Q. ARE YOU THE SAME CHRISTOPHER M. JACOBI THAT FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

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

A. The purpose of my rebuttal testimony is to address certain recommendations made by witness Lane Kollen on behalf of the Kentucky Attorney General. Specifically, I address his recommendations regarding the reduction in the Company's payroll expense and payroll taxes associated with the reduction in payroll expense. I also address his recommendations regarding the Company's long-term Debt Rate.

II. DISCUSSION

Q. PLEASE BRIEFLY SUMMARIZE MR. KOLLEN'S ADJUSTMENTS RELATED TO THE COMPANY'S PAYROLL EXPENSE AND TAXES ASSOCIATED WITH THE PAYROLL EXPENSE.

A. Mr. Kollen's discussion of the Company's payroll expense and related payroll tax expense begins on page 21 of his Direct Testimony. Mr. Kollen is critical of the Company's forecasted payroll costs in the test year, calling it a "hodge-podge of budget/forecast methodologies" and believes the forecasted increases are unreasonable. He proposes using the Company's most recent actual monthly payroll expense and escalate it by 3 percent annually for the test year. The effect of his recommendation is a $1.125 million reduction in payroll expense, resulting in a $1.127 million reduction in the revenue requirement. His reduction also produces a corresponding reduction in the payroll taxes of $0.086 million to the revenue requirement.

Q. ARE HIS ADJUSTMENTS REASONABLE?

A. No.

Q. PLEASE EXPLAIN WHY MR. KOLLEN'S ADJUSTMENTS ARE UNREASONABLE AND SHOULD BE REJECTED BY THE COMMISSION.

A. Mr. Kollen's analysis looks at payroll expenses in isolation and his recommendation is based on a narrow set of data. This approach cherry picks certain data points and fails to consider other changes in O&M. While payroll expenses through September are lower than the 2019 budget, contractor O&M expenses are above budget. This is an important consideration as Duke Energy Kentucky considers both employee and contractor expenses when managing its workforce. As noted in the table below, through December, the Company's actual average monthly contractor O&M expense in 2019 is $3.034 million. In comparison, the Company included average monthly contractor O&M of $2.553 million in the test year. When combining these contractor O&M expenses with the payroll expenses cited in Mr. Kollen's testimony, test year O&M is lower than 2019 actuals. This example highlights the unreasonableness of singling out only a select set of components while excluding others.

Contractor O&M	2019 Budget	2019 Actual	2019 Actuals vs. Budget
January	$1,937,974	$3,517,665	$1,579,691
February	$1,863,512	$2,506,803	$643,291
March	$2,063,438	$2,703,079	$639,642
April	$2,403,454	$3,114,710	$711,255
May	$3,628,041	$3,568,157	($59,884)
June	$2,485,418	$3,775,784	$1,290,367
July	$2,083,585	$2,289,379	$205,793
August	$2,047,817	$2,872,747	$824,930
September	$2,470,222	$2,940,883	$470,661
October	$2,772,909	$3,113,313	$340,404
November	$2,026,074	$2,365,607	$339,533
December	$1,857,226	$3,639,498	$1,782,272
Total	**$27,639,670**	**$36,407,625**	**$8,767,954**

Contractor O&M	Test Period
Apr-20	$3,388,907
May-20	$5,308,637
Jun-20	$2,899,212
Jul-20	$2,068,947
Aug-20	$2,022,399
Sep-20	$2,058,155
Oct-20	$1,978,057
Nov-20	$1,930,236
Dec-20	$1,867,308
Jan-21	$2,530,531
Feb-21	$2,217,095
Mar-21	$2,365,444
Total	**$30,634,926**

As noted in Attachment CMJ-Rebuttal-1 to my testimony, performing Mr. Kollen's same calculation and logic that he prepared in calculating his payroll expense adjustment to contractor expenses would yield an increase to the Company's test period expense for contractor costs of $7.1 million.

Q. IS THE COMPANY PROPOSING A $7.1 MILLION INCREASE TO ITS FILED TEST PERIOD REVENUE REQUIREMENT FOR HIGHER CONTRACTOR EXPENSES?

A. No. The Company merely provided the calculation to show that the payroll expense adjustment Mr. Kollen is proposing cannot be made in isolation. The Company disagrees with Mr. Kollen's proposed payroll expense and associated payroll tax adjustments and recommends the Commission reject this adjustment. However, if the Commission were to agree to this adjustment, it should also recognize the adjustment to the Company's contractor expenses accordingly.

Q. PLEASE BRIEFLY SUMMARIZE MR. KOLLEN'S RECOMMENDED ADJUSTMENT RELATED TO THE COMPANY'S LONG-TERM DEBT RATE.

A. Mr. Kollen's discussion of the Company's long-term debt begins on page 57 of his Direct Testimony. His opinion is that the Company's forecasted long-term debt rate of 4.0 percent for its planned September 2020 debt issuance is excessive and should be reduced to 3.68 percent. This gives the result of a forecasted long-term debt rate of 4.06% vs. the Company's filed rate of 4.073%. The result of his recommendation is a reduction of $0.056 million to the Company's base revenue requirement.

Q. IS MR. KOLLEN'S RECOMMENDED ADJUSTMENT TO THE COMPANY'S LONG-TERM DEBT RATE REASONABLE?

A. No. The Commission should reject Mr. Kollen's recommendation.

Q. PLEASE EXPLAIN WHY DUKE ENERGY KENTUCKY DISAGREES WITH THIS RECOMMENDATION.

A. The long-term debt rate as contained in the Company's application was reasonable. Mr. Kollen's recommendation to adjust this one single item for a reduction in cost is opportunistic and is to the exclusion of all other items in the Company's test year revenue requirement that may have increased. Duke Energy Kentucky is not permitted to update all the elements of its revenue requirement to reflect actual results. The purpose of a forecasted test year is to project what the Company's revenue requirement is likely to be. It is unfair and unreasonable to single out one component of the revenue requirement that may have been lower than expected without consideration of all other components that may have increased as I discussed above.

Mr. Kollen has not claimed that the Company's methodology for forecasting the long-term debt rate was somehow unreasonable. He is merely selecting one component that would reduce the Company's revenue requirement by updating it for a post-filing change that has occurred to reflect an actual cost rate to the exclusion of all other items that may have increased the Company's revenue requirement. Such a position is contrary to the very purpose of a forecasted test year allowed under Kentucky Law. The Commission should not adopt Mr. Kollen's recommendation, especially in isolation and without consideration of all other changes in variables that may have increased the Company's revenue requirement.

Furthermore, even if the commission were to determine that the Treasury yield for the 2020 debt issuance should be updated to reflect updated market rates, Mr. Kollen's calculation of the long-term rate is incomplete. The proposed 3.68

percent rate is representative of a December 6, 2019 debt issuance, not a September 2020 issuance. The calculation fails to consider the forward curve, which is representative of the current market expectation for interest rates at the time of the issuance. In doing so, Mr. Kollen underestimates the cost of debt.

III. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Duke Energy Kentucky, Inc.
Contractor Expense Analysis
Case No. 2019-00271
For the Test Year Ended March 31, 2021
($ Millions)

Month		2019	3.0% Incr 2020	3.0% Incr 2021
Jan	Actual	$ 3.518	$ 3.624	$ 3.732
Feb	Actual	2.507	2.582	2.660
Mar	Actual	2.703	2.784	2.868
Apr	Actual	3.115	3.208	
May	Actual	3.568	3.675	
Jun	Actual	3.776	3.889	
Jul	Actual	2.289	2.358	
Aug	Actual	2.873	2.959	
Sep	Actual	2.941	3.029	
Oct	Actual	3.113	3.206	
Nov	Actual	2.366	2.437	
Dec	Actual	3.639	3.748	

Test Year Expense - Based on 3.0% Escalations over 2019 Actual	$ 37.770
Contractor Expense in Test Year - As Filed By Company	30.635
Test Year Expense increase if based on 2019 actuals	$ 7.135

VERIFICATION

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

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

Christopher Jacobi
Christopher M. Jacobi Affiant

Subscribed and sworn to before me by Christopher M. Jacobi on this 10 day of January, 2020.

JENNY PATTANA NOTARY PUBLIC MECKLENBURG COUNTY, NC

Jenny Pattana
NOTARY PUBLIC

My Commission Expires: 06/08/2020

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2019-00271

REBUTTAL TESTIMONY OF

JEFF L. KERN

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

January 31, 2020

TABLE OF CONTENTS

PAGE

ATTACHMENTS:

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeff L. Kern. My business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

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

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

Q. ARE YOU THE SAME JEFF L. KERN THAT FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

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

A. The purpose of my Rebuttal Testimony is to respond to the recommendations made by Glenn A. Watkins on behalf of the Kentucky Attorney General as it relates to the Company's proposed residential customer charge.

II. DISCUSSION

Q. PLEASE BRIEFLY SUMMARIZE MR. WATKINS' TESIMONY.

A. Mr. Watkins addresses the Company's proposal to increase its residential customer charge. Through his testimony, Mr. Watkins argues that the Company's charge is currently too high, but ultimately recommends no change to the charge.

Q. DOES DUKE ENERGY KENTUCKY AGREE WITH MR. WATKINS' RECOMMENDATION REGARDING THE PROPOSED RESIDENTIAL CUSTOMER CHARGE?

A. No.

Q. PLEASE EXPLAIN WHY DUKE ENERGY KENTUCKY DOES NOT AGREE WITH MR. WATKINS' ASSESSMENT.

A. Mr. Watkins bases his conclusion on three components, "rate shock," the reclassification of costs, and competitive pricing. His reliance on each of these components is flawed.

Q. DO YOU AGREE WITH MR. WATKINS, THAT THE INCREASE IN THE CUSTOMER CHARGE FOR RATE RS WILL RESULT IN "RATE SHOCK" TO NUMEROUS RESIDENTIAL CUSTOMERS?

A. No. The increase of 27% would only apply to a customer with zero usage. As can be seen on Schedule N of the filing the percentage increase for usage of 300 kWh is very close to the average percentage increase for the entire Rate RS. Over 90% of Duke Energy Kentucky's residential customers use more than 300 kWh per month (See Attachment JLK-Rebuttal-1). For the few customers with usage close to zero, an increase of only $3 per month is unlikely to result in "rate shock."

Q. DO YOU AGREE WITH MR. WATKINS' ASSERTION THAT CERTAIN DISTRIBUTION COSTS WHICH DUKE ENERGY KENTUCKY CLASSIFIED AS "CUSTOMER-RELATED" ARE NOT TRUE CUSTOMER COSTS?

A. No. The quote included on page 7 of Mr. Watkins' testimony from Principles of Public Utility Rates, by Professor James C. Bonbright, states that these costs do not belong in any category. This implies that it would be just as erroneous to include them in the energy or demand component as the customer component. However, these costs must be included somewhere, so even if you accept the premise that they are not "true customer costs," they are more closely aligned to customer costs than to energy or demand. Based on the generally accepted minimum size method, these costs are required just to connect a customer to the system regardless of the amount of demand or energy actually used.

Q. ON PAGE 12 OF MR. WATKINS' TESTIMONY HE STATES THAT "CONSUMERS AND THE MARKET HAVE A CLEAR PREFERENCE FOR VOLUMETRIC PRICING." DID MR. WATKINS OFFER ANY SUPPORT FOR THIS ASSERTION?

A. No. There was no support in his testimony and when asked in discovery whether he had any research or studies that supported his statement he had nothing to offer.[1] Instead, in his response to the discovery question number 37 submitted to the Attorney General, he asserts that his position that "consumers and the market have

[1] Attorney General Response to Duke Energy Kentucky's DR-01-37.

a clear preference for volumetric pricing" is "common knowledge to the common man wherein no research or studies are required or have been conducted."

Q. DO YOU AGREE WITH MR. WATKINS' REASONING?

A. No. It is evident from Mr. Watkins' response to the discovery question that he performed no studies or analyses and he apparently did not rely on any to support his statement. His assertion that it is "common knowledge to the common man" belies any rationale evaluation of the experiences of the common man.

Like Mr. Watkins, I am also not aware of any research or studies that show that consumers prefer volumetric-based pricing for competitive market-based products and services. However, numerous examples can easily refute Mr. Watkins' thesis. For example, many cellular phone users have rate plans that are based mostly on fixed monthly prices that are independent of usage. Many, if not most, cable television providers' rate plans are fixed, and not based on the volume of viewing. Car rental companies normally charge a fixed rate per day with unlimited mileage.

Using the cellular phone industry as an example, as cellular phones were first becoming popular, most companies charged customers by the minute for voice calls, by the text for texting and by the gigabyte for data. As the industry evolved almost all carriers now offer unlimited talk, text and data for a set monthly charge. Since there are many cell phone carriers in competition with each other, this implies that customers may actually prefer a fixed monthly charge to a volumetric one.

I do not offer these examples as an expert in pricing for cellular service, cable TV or car rentals. However, as a customer of these services, I believe these examples, which are also know to the common man, illustrate a pricing preference based on fixed rather than volumetric services.

Q. PLEASE EXPLAIN HOW DUKE ENERGY KENTUCKY'S PROPOSED CUSTOMER CHARGE INCREASE IS REASONABLE.

A. As shown on WP FR-16(7)(v), the class cost of service study, sponsored by Company Witness Jim Ziolkowski, supports a customer charge of $14.29 per month. The Company is proposing $14.00 per month which is slightly less.

Q. HOW DOES DUKE ENERGY KENTUCKY'S PROPOSED CUSTOMER CHARGE COMPARE TO OTHER ELECTRIC SERVICE PROVIDERS IN KENTUCKY?

A. As can be seen on Attachment JLK-2 from my initial testimony, Duke Energy Kentucky's current customer charge is the third lowest in the commonwealth. If the Commission approves the proposed charge, it will be closer to the middle, but still under the median.

Q. HOW DOES DUKE ENERGY KENTUCKY'S PROPOSED CUSTOMER CHARGE COMPARE TO THE OTHER ELECTRIC SERVICE PROVIDERS IN THE STATES MENTIONED IN MR. WATKINS' TESTIMONY AS HAVING A POLICY OF MAINTAINING RELATIVELY LOW FIXED MONTHLY CUSTOMER CHARGES?

A. Mr. Watkins mentions Maryland, Washington State, Virginia, Montana, Oregon, Pennsylvania and South Carolina as states with Commissions that have a policy of maintaining relatively low fixed monthly customer charges. Based on Mr. Watkins' testimony, one would expect Duke Energy Kentucky's customer charge to be much higher than any electric service provider in these other states. However, as can be seen in Attachment JLK-Rebuttal-2, Duke Energy Kentucky's proposed customer charge appears reasonable when compared to electric service providers in those states. For example, customer charges in Virginia range from $31.35 to $7.96, with the majority of charges $14.00 or more.

III. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Duke Energy Kentucky
Residential (RS) Average Usage
12 Months Ended November 30, 2019

Average Monthly kWh	Number of Accounts	Percent	Cumulative Frequency	Cumulative Percent
<100	3,601	2.72%	3,601	2.72%
100-199	3,599	2.71%	7,200	5.43%
200-299	5,435	4.10%	12,635	9.53%
300-399	7,994	6.03%	20,629	15.56%
400-499	9,940	7.50%	30,569	23.06%
500-599	11,216	8.46%	41,785	31.52%
600-699	11,743	8.86%	53,528	40.37%
700-799	11,546	8.71%	65,074	49.08%
800-899	10,533	7.94%	75,607	57.03%
900-999	9,361	7.06%	84,968	64.09%
>1,000	47,616	35.91%	132,584	100.00%

Duke Energy Kentucky
Customer Charges in Other States

State	Utility / Cooperative	Customer Charge
Virginia	Craig-Botetourt Electric Cooperative	$31.35
Virginia	Central Virginia Electric Cooperative	$30.75
Virginia	BARC Electric Cooperative	$29.16
Virginia	Northern Neck Electric Cooperative	$29.00
Virginia	Prince George Electric Cooperative	$29.00
Virginia	Community Electric Cooperative	$26.15
Virginia	Shenandoah Valley Electric Cooperative	$25.00
Virginia	Mecklenburg Electric Cooperative	$24.00
Virginia	Southside Eectric Cooperative	$18.00
Pennsylvania	PPL Electric Utilities	$17.94
Maryland	A&N Electric Cooperative	$14.00
Kentucky	**Duke Energy Kentucky Proposed**	**$14.00**
Virginia	A&N Electric Cooperative	$14.00
Virginia	Rappahannock Electric Cooperative	$14.00
Pennsylvania	Duquesne Light Company	$12.50
Virginia	Old Dominion Power Company	$12.00
Virginia	Powell Valley Electric Cooperative	$12.00
South Carolina	Duke Energy Carolinas	$11.96
South Carolina	Progress Energy	$11.78
Maryland	Choptank Electric Cooperative	$11.75
Pennsylvania	Metropolitan Edison Company	$11.25
Pennsylvania	Pennsylvania Electric Company	$11.25
Pennsylvania	Citizens' Electric Company of Lewisburg	$11.24
Oregon	Portland General Electric Company	$11.00
Kentucky	**Duke Energy Kentucky Current**	**$11.00**
Pennsylvania	Pennsylvania Power Company	$11.00
Pennsylvania	Wellsboro Electric Company	$10.95
Pennsylvania	PECO Energy Company	$9.97
Maryland	Southern Maryland Electric Cooperative	$9.50
Oregon	Pacific Power	$9.50
Maryland	Sumerset Rural Electric Cooperative	$9.00
Washington	Avista Utilities	$9.00
South Carolina	South Carolina Electric & Gas Company	$9.00
Pennsylvania	UGI Utilities Inc	$8.74
Pennsylvania	Pike County Light & Power Company	$8.50
Maryland	Delmarva Power & Light	$8.30
Maryland	Potomac Electric Power	$8.01
Oregon	Idaho Power Company	$8.00
Virginia	Appalachian Power Company	$7.96
Maryland	BG&E	$7.90
Washington	Pacific Power	$7.75
South Carolina	Lockhart Power Company	$7.50
Washington	Puget Sound Energy	$7.49
Pennsylvania	West Penn Power Company	$7.44
Virginia	Dominion Energy	$6.58
Montana	MDU Electric	$6.20
Maryland	Potomac Edison	$5.70
Pennsylvania	Borough of Schuylkill Haven	$5.06
Maryland	Berlin Electric Service	$4.60
Montana	NWE Electric	$4.25
Maryland	Hagerstown Light	$4.11
Maryland	Thurmont Municipal Light Company	$3.00

Sources:
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www.psc.mt.gov
www.oregon.gov/puc
www.puc.state.pa.us
www.psc.sc.gov

VERIFICATION

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

The undersigned, Jeff L. Kern, Lead Rates & Regulatory Strategy Analyst, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing rebuttal testimony and that it is true and correct to the best of his knowledge, information and belief.

Jeff L. Kern, Affiant

Subscribed and sworn to before me by Jeff L. Kern, on this 17th day of January, 2020.

NOTARIAL SEAL STATE OF OHIO

ADELE M. FRISCH
Notary Public, State of Ohio
My Commission Expires 01-05-2024

NOTARY PUBLIC

My Commission Expires: 1/5/2024

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2019-00271

REBUTTAL TESTIMONY OF

ZACHARY KUZNAR, PhD

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

January 31, 2020

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Zachary Kuznar and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

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

A. I am employed by Duke Energy Carolinas, LLC (DEC) as Managing Director Combined Heat & Power (CHP) Microgrid and Energy Storage Development. DEC is a subsidiary of Duke Energy Corporation (Duke Energy) which provides various services to Duke Energy Kentucky, Inc. (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy.

Q. ARE YOU THE SAME ZACHARY KUZNAR THAT FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

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

A. The purpose of my testimony is to discuss the Company's proposal for a battery storage pilot program on its distribution system in the service territory and explain how and why the location of that pilot storage program has changed. Next, I respond to the recommendations made by Mr. Brian Collins on behalf of Northern Kentucky University, as well as those of Mr. Lane Kollen on behalf of the Kentucky Attorney General.

II. DISCUSSION OF NEW BATTERY LOCATION

Q. PLEASE DESCRIBE THE CURRENT PROPOSED DISTRIBUTION BATTERY ENERGY STORAGE SYSTEM.

A. Duke Energy Kentucky has decided to change the location from the originally proposed battery storage project located on the Thomas More circuit. As discussed in our response to discovery question STAFF-DR-02-80, that project ran into technical complications with the initially selected site that resulted in a change to our proposed battery location after the application was filed. Duke Energy Kentucky is now planning to construct a 3.4MW/6MWH battery storage project at our existing Crittenden Solar Farm. The project will interconnect on the Crittenden 42 circuit. This project's primary application will remain frequency regulation in PJM but will also be used to study the integration of battery storage with solar energy. These potential applications include solar smoothing, solar shifting and voltage support. This project will enable us to study how battery storage can mitigate the impact of distributed generation resources on our distribution system.

Q. IS THE COMPANY PROPOSING ANY CHANGES WITH RESPECT TO THE TYPE OF TECHNOLOGY DESCRIBED IN ITS APPLICATION?

A. No. This system will still incorporate lithium ion batteries, which is the preferred technology for this application.

Q. PLEASE EXPLAIN THE PURPOSE OF AND NEED FOR THIS PROJECT.

A. As discussed above, the battery will provide necessary ancillary services to the PJM market. In addition, this battery will be used to study how batteries can be used to integrate renewable energy on the distribution system. This includes shifting energy to periods of peak demand, smoothing the output of the solar system and providing voltage support. Additionally, customers will benefit from the lessons learned from this project that will enable future deployments of energy storage projects.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO HOW IT WILL CONSTRUCT THE BATTERY STORAGE PROJECT?

A. No.

Q. HOW WILL DUKE ENERGY KENTUCKY ENGAGE WITH THE LOCAL COMMUNITY RELATED TO THE INSTALLATION OF THIS PROJECT?

A. As with any project, Duke Energy Kentucky regularly meets with local community leaders, including city managers and/or engineers in advance of construction work being performed. Duke Energy Kentucky would follow this same process with this project.

Q. HAS THE COMPANY COMPLETED ENGINEERING FOR THE BATTERY STORAGE PROJECT?

A. The Company has completed its engineering study that was used to develop the size of the proposed project, 3.4MW and 6MWH. This engineering report has previously been entered into the record as STAFF-DR-02-084 Confidential Attachment. A preliminary site plan and one-line diagram have also been prepared and were used in the interconnection application submitted for this project. Additional engineering details will be determined as the Company prepares to initiate its RFP for the project.

Q. WILL THE COMPANY NEED ANY SPECIFIC PERMITS FOR CONSTRUCTION OF THE BATTERY STORAGE PROJECT?

A. The Company does not anticipate needing any specific permitting except for local construction permits that may be required. This project will be directly tied into the Company's own distribution system adjacent to an existing solar farm. This project will interconnect to the grid using the standard Duke Energy Kentucky interconnection process, which has already been submitted with Duke Energy Kentucky. The Company is treating the interconnection of this project like that of any other 3rd part interconnection in terms of evaluation and order of evaluation. The project will also require a Wholesale Market Participation Agreement with PJM in order to participate in the wholesale markets.

Q. WILL DUKE ENERGY KENTUCKY'S CUSTOMERS CONTINUE TO BENEFIT FROM PARTICIPATION IN THE PJM ANCILLARY SERVICES MARKET?

A. Yes, customers will receive the benefits of this asset's participation in the PJM ancillary services market. The net benefits of this market participation will be received by customers through the Company's Fuel Adjustment Clause (Rider FAC) and the Company's Profit Sharing Mechanism (Rider PSM). The current plan for the battery is to participate in PJM's regulation market as a fast responding REG D asset. Other market opportunities such as capacity value may become available in the future as PJM finalizes its battery rules in response to FERC Order 841.

Q. WHAT IS THE ESTIMATED ANNUAL VALUE OF BENEFITS FOR THE FREQUENCY REGULATION SERVICES AT PJM?

A. Currently the PJM regulation D market is approximately \$20 per MW each hour. Using this figure, the estimated annual revenues from the PJM Reg D market for this project would be approximately \$470,000. Actual net revenues will flow through the Company's rider mechanisms to customers.

Q. WHAT FACTORS WERE RELEVANT TO THE SELECTION OF THIS REVISED LOCATION?

A. The first priority was to ensure that this location is suitable for providing frequency regulation to PJM while maintaining adequate power quality on the distribution circuit. This analysis was provided in our response to discovery question STAFF-DR-02-084. We also wanted to use this project to test another application of energy storage in addition to ancillary services. At this location, we will be able to test solar integration applications as discussed above. Finally, we needed to maintain our current placed in-service target for this pilot project. Locating the project on a previously developed site currently owned by Duke Energy Kentucky reduces our development risk for this project.

Q. PLEASE DISCUSS THE INFORMATION THAT DUKE ENERGY KENTUCKY WILL OBTAIN UNDER THE PILOT GIVEN ITS NEW LOCATION.

A. As discussed in my Direct Testimony, the benefits of this project will give Duke Energy Kentucky critical insight going forward with regard to energy storage. As technology continues to evolve in the energy space, as assets continue to become more distributed, and as costs continue to decline for technologies such as energy storage, quantifying the values it can provide are important for the Company. At the new location the Company will gain valuable insights on using storage to help integrate renewable energy on the system. The operational experience and information obtained will be invaluable to future energy storage deployments and economic modeling.

Q. HAS THE ESTIMATED COST OF THE PILOT CHANGED?

A. Duke Energy Kentucky has prepared a revised cost estimate for this battery project, provided in response to discovery question STAFF DR-02-82. The new estimated cost is $8.2 million including contingency and AFUDC and is consistent with the cost of the project originally proposed with the hospital. There is no change in the revenue requirement since the capital costs and in-service date assumptions are the same as originally projected with the initial project location.

Q. WHAT IS THE ESTIMATED ONGOING ANNUAL COST OF OPERATION OF THE BATTERY STORAGE SYSTEM?

A. The estimated annual ongoing cost of operation is approximately $163,000 per year and is consistent with the cost of the project originally proposed with the hospital. As Ms. Lawler noted in her direct testimony, these costs have not been included in the forecasted test period.

Q. IS THE COMPANY REQUESTING APPROVAL OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY (CPCN) FOR THIS PROJECT?

A. As I previously mentioned, the Company believes that the project should qualify as an ordinary extension of the existing system in the ordinary course of business. The Company has reached this conclusion given the project's size, cost, location and purpose. The project will not create a wasteful duplication of plant, equipment or facilities. Battery storage is an emerging technology and its deployment on the distribution grid for resiliency and enhanced reliability is new to the current way utilities distribute energy. Because the project will be connected to Duke Energy Kentucky's own distribution system, it will not conflict with existing certificates or service of other utilities in the general or contiguous area. Finally, due to the project's relative size and cost, it does not involve sufficient capital outlay to materially affect the existing financial condition of the Company. Nonetheless, if the Commission determines a CPCN is necessary, then the Company requests the Commission grant CPCN approval with its application in this case.

Q. WILL DUKE ENERGY KENTUCKY PROVIDE THE COMMISSION WITH ANY ONGOING REPORTING ON THE LEARNINGS GAINED AS PART OF THIS PILOT PROGRAM?

A. Yes. Duke Energy Kentucky will provide the Commission with annual reporting including but not limited to the following:

- A quantification of the total ancillary services provided to the grid by the battery including what types of services were provided (spinning reserve, regulation up or down, *etc.*);
- A summary of how the battery enhanced economic operations and how it was beneficial to Duke Energy Kentucky's operational knowledge; and
- On-going operations and maintenance costs.

III. DISCUSSION OF INTERVENOR COMMENTS

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS OF MR. COLLINS ON BEHALF OF NORTHERN KENTUCKY UNIVERSITY.

A. Mr. Collins makes several recommendations that he describes as customer protections the Commission should require if it approves the Company's battery storage proposal. These recommendations are as follows:

- The Company should be required to document all revenues generated by the Battery Storage Project and provide sufficient information to allow the tracking of those revenues back to customers either through the Rider FAC or Rider PSM;
- The Company should maintain the necessary information to evaluate the benefits of the Battery Storage Project to customers;
- If the Company files another rate case prior to the expiration of the Battery Storage Project pilot program, the Company should be required to file a cost/benefit study in the public record for the Battery Storage Program at the time of the rate case;

- If the Pilot Program expires at the end of the proposed three-year period but before the next rate case, the Company should be required to file a cost/benefit study regarding the Battery Storage Project six months after expiration of the pilot. Again, the study should be filed in the public record if possible;
- The Company should be limited to only that level of investment necessary to install the Battery Storage Project at the solar farm and the Company should be prohibited from further investments in battery storage until a full analysis of the current pilot program is performed and filed with the Commission;
- If the Commission approves the battery project, Duke Energy Kentucky should be prohibited from expanding the Battery Storage Project before the expiration of the current program. If the Commission does allow the Company to seek expansion of the program before the currently proposed expiration by way of a subsequent filing, all parties to the current rate case should be notified by Duke Energy Kentucky and be afforded the opportunity to participate in the filing or proceeding;
- Based on Commission approval of the battery project, the Commission should review the results of the pilot program before approving any future battery storage investments on the Duke Energy Kentucky system; and

- The Commission's approval of this pilot should not be construed as a carte blanche endorsement of future battery storage investments, even with the suggested ratepayer protections previously articulated.

Q. DO YOU AGREE WITH THESE RECOMMENDATIONS?

A. I am pleased that Mr. Collins recognizes the value of this project and conditionally supports its approval in this proceeding. Mr. Collins conditions his support based on a variety of consumer protections that he believes are necessary. I believe that some of these requests are reasonable conditions to include, while other are overly restrictive and existing Commission rules are sufficient to protect consumers.

Q. WHAT CONDITIONS PROPOSED BY MR. COLLINS DO YOU SUPPORT?

A. I am supportive of the proposed requirement that the Company track all revenues associated with the battery project and maintain the information necessary to assess the benefits of the project. I also support the requirement to provide an updated cost benefit analysis the earlier of the Company's next rate case or within 6 months after the project has been placed in service for three years. I agree that any approval of the proposed pilot project is not a carte blanche approval for future battery storage projects by the Commission.

Q. WHAT CONDITIONS PROPOSED BY MR. COLLINS DO YOU BELIEVE ARE UNNECESSARY?

A. Mr. Collins seeks to place additional restrictions on Duke Energy Kentucky's ability to move forward with new battery storage projects until the pilot program is complete (three years) and the Commission has reviewed the cost benefit analysis he has proposed be required. While we recognize there is value in the Commission reviewing a full cost benefit analysis as proposed, it may not be in the interest of customers or the Commission to prevent the installation of new storage projects for more than three years as proposed. Duke Energy Kentucky may identify additional projects to install prior to the end of this proposed pilot period that are in the customer's interest to pursue. I believe the standard Commission approval process is enough and these additional restrictions proposed by Mr. Collins are unnecessary.

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS BY MR. KOLLEN ON BEHALF OF THE KENTUCKY ATTORNEY GENERAL.

A. Mr. Kollen's discussion of the Company's Battery Pilot begins on page 60 of his direct testimony. Mr. Kollen recommends that the Commission deny the Company's proposal and proposes a reduction of $0.346 million from the Company's revenue requirement.

Q. WHAT ARE THE BASIS OF MR. KOLLEN'S RECOMMENDATION TO ELIMINATE THE BATTERY STORAGE PILOT PROGRAM?

A. Mr. Kollen claims: 1) the project is not necessary for reliability; 2) the project is not economic; 3) the pilot program will be managed by another Duke Energy affiliate and/or DEBS, not Duke Energy Kentucky, and should be pursued by and allocated to the larger Duke Energy utilities, such as Duke Energy Kentucky's parent company, Duke Energy Ohio, not Duke Energy Kentucky, the smallest Duke Energy utility; and 4) other Duke Energy utilities and other unrelated utilities can implement pilot programs and provide lessons learned to Duke Energy Kentucky for possible future deployment of this technology.

Q. ARE MR. KOLLEN'S CRITICISMS OF THE BATTERY PILOT VALID?

A. No.

Q. PLEASE EXPLAIN WHY HIS CRITICISMS ARE INVALID.

A. As discussed above, Mr. Kollen raises four concerns with this proposed battery storage project. His first is that the project is not necessary for reliability. Being strictly required for reliability is simply not a requirement of all investments made by Duke Energy Kentucky. Through its participation in PJM, renewable integration testing, and general lessons learned, this project will provide value for customers. Moreover, a small pilot like the one proposed will allow Duke Energy Kentucky to gain experience with battery projects on its distribution system that in turn could lead to broader reliability-based projects in the future as the technology continues to develop.

Mr. Kollen is also opposed to this project because it does not provide positive economic benefits. As a pilot project, I have not claimed that this project will have a positive economic impact when viewed in isolation. As new technology, there is more uncertainty in the cost benefit analysis. Furthermore, changes in costs and market rules with the adoption of FERC Order 841 by PJM could improve the underlying economics. In addition, as discussed in my direct testimony, the lessons learned from this pilot project will be valuable to Duke Energy Kentucky and our customers in the future.

Mr. Kollen also claims this project will be managed by an affiliate and not Duke Energy Kentucky. This is not true. In my current role, I am able to support all of Duke Energy's regulated utilities, including Duke Energy Kentucky. This project will be owned and operated by Duke Energy Kentucky like any other utility asset.

Finally, Mr. Kollen believes that Duke Energy Kentucky can ignore battery storage technology and let other Duke Energy affiliates operate pilot projects. Duke Energy will strive to incorporate as many lessons as possible across all of its utilities for this and other new technologies. This fact is not a substitute for gaining real project experience for Duke Energy Kentucky employees. We will need hands on experience operating a battery storage project in PJM in Kentucky that cannot be replicated in other jurisdictions.

Q. SHOULD THE COMMISSION DISREGARD MR. KOLLEN'S RECOMMENDATION TO ELIMINATE DUKE ENERGY KENTUCKY'S BATTERY STORAGE PILOT PROJECT AND REDUCE THE COMPANY'S PROPOSED REVENUE REQUIREMENT BY $.346 MILLION?

A. Yes. For the reasons I've discussed above, the Commission should disregard Mr. Kollen's recommendation, and approve the Company's battery pilot as discussed in my rebuttal testimony and supported in this case.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

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

The undersigned, Zachary Kuznar, Managing Director CHP Microgrid & Engineer Storage Development, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing rebuttal testimony and that it is true and correct to the best of his knowledge, information and belief.

Zak Kuznar
Zachary Kuznar, Affiant

Subscribed and sworn to before me by Zachary Kuznar, on this 13 day of January, 2020.

E. Minna Rolfes
NOTARY PUBLIC

My Commission Expires: July 8, 2022

NOTARY PUBLIC ★ STATE OF OHIO ★

E. MINNA ROLFES-ADKINS
Notary Public, State of Ohio
My Commission Expires
July 8, 2022

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2019-00271

REBUTTAL TESTIMONY OF

SARAH E. LAWLER

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

January 31, 2020

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

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

Q. ARE YOU THE SAME SARAH E. LAWLER THAT SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to a number of the recommendations made by the Attorney General's witness Lane Kollen. Specifically, I will address Mr. Kollen's recommendations related to:

(1) Inventories Financed by Vendors;

(2) Cash Working Capital;

(3) Rate Case Expense Regulatory Asset; and

(4) Depreciation Expense.

I will also address adjustments proposed by Mr. Kollen that the Company does not oppose, adjustments identified by the Company through discovery, and the resulting revised revenue requirement increase being requested by the

Company. Finally, I will address the recommendations raised by Northern Kentucky University's witness Mr. Collins related to the Company's proposed storm deferral.

II. INVENTORIES FINANCED BY VENDORS

Q. PLEASE DESCRIBE MR. KOLLEN'S PROPOSAL REGARDING VENDOR FINANCING OF INVENTORIES.

A. Mr. Kollen recommends that Duke Energy Kentucky's rate base be reduced to include an offset to fuel inventories for accounts payable balances associated with these inventories. He recommends an additional reduction to rate base for accounts payable balances associated with materials and supplies (M&S) inventories if the Commission rejects his proposal to deviate from its historical precedent and approve his recommendation of $0 for cash working capital. He calculates the impact of his adjustment related to fuel inventories to be a $0.187 million reduction to the Company's proposed revenue requirement. Based on his estimate, Mr. Kollen calculates the conditional adjustment related to M&S inventories will reduce the Company's revenue requirement by an additional $1.478 million.

Q. DO YOU AGREE WITH THE ADJUSTMENT TO REDUCE THE REVENUE REQUIREMENT BY $0.187 MILLION FOR THE FINANCING OF FUELS INVENTORIES?

A. No.

Q. PLEASE EXPLAIN.

A. Accounts payable amounts are essentially components of a utility's cash working capital. Mr. Kollen provided a reasonable description of lead/lag studies in his recent testimony in an Atmos Energy case before this Commission. In his words, "[f]undamentally, the lead/lag study measures the cash investment provided by either investors (positive) or customers (negative) on average over the [cash working capital] study period."[1] Regarding Mr. Kollen's proposal in this instant case, he is asking the Commission to reduce rate base for accounts payable, an investment by customers in his description, but ignores any cash investment, such as receivables, by the Company's investors. Where a "payable" is a cash benefit to the Company, a receivable is a cash detriment to the Company. Even if the Commission accepted Mr. Kollen's attempt to interject lead/lag principles, it must recognize that Mr. Kollen's approach is one-sided and self-serving. He is only proposing to modify the cash working capital calculation for components of a lead/lag approach that favor the Attorney General's position. Mr. Kollen proposes only to reduce rate base to reflect the benefit of the cash float for accounts payable but ignores the counter issue of the timing between the Company providing a service and receiving its revenue.

The Commission should ignore Mr. Kollen's proposal. It is biased to a fault and it is contrary to the historical precedent the Commission has used for establishing rate base for Duke Energy Kentucky.

The Company's calculation of cash working capital relies on a methodology that follows Commission's historical precedent for Duke Energy Kentucky. The 1/8th Operating and Maintenance (O&M) approach is balanced and, as evidenced by the fact that it is a methodology used by this Commission, the Federal Energy

[1] Kollen's direct testimony in Case No. 2018-00281, p. 36.

Regulatory Commission, and other regulators, confirms that it is widely considered to be a reasonable approach. This has been a proven method of calculating cash working capital, it complies with the Commission's rules and practice, and the Company sees no reason to deviate.

Q. IS MR. KOLLEN'S PROPOSED ADJUSTMENT IN THIS INSTANCE DUPLICATIVE OF HIS PROPOSAL TO SET CASH WORKING CAPITAL TO ZERO?

A. Yes. If the Commission agrees to Mr. Kollen's recommendation to set cash working capital balances to zero in the absence of a lead/lag study, which it should not for the reasons I discuss below, there is no need to make this adjustment too. Mr. Kollen even makes this same argument when he discusses accounts payable offsets to M&S inventories. The rationale about applying accounts payable values to fuel inventories is no different than the rationale to apply accounts payable values to M&S inventories. As discussed above, his proposal is also one-sided as he is only addressing accounts payable but not addressing accounts receivable.

Q. DO YOU AGREE WITH THE ADJUSTMENT TO REDUCE THE REVENUE REQUIREMENT BY $1.478 MILLION FOR THE FINANCING OF M&S INVENTORIES?

A. No. Mr. Kollen is conflating two rate base items – cash working capital and inventories. Both are traditionally acceptable components of rate base. Again, the Company has performed a calculation of cash working capital based on a method that has been consistently accepted and approved by the Commission. The Company has also included inventory balances in rate base which is a commonly acceptable component of rate base. M&S inventories and cash working capital are two separate components of rate base that should be examined individually and on their own merits. Mr. Kollen suggests that if the Commission rejects his argument to set cash working capital to zero, that an adjustment to M&S inventories is needed for an accounts payable offset. For the reasons I've discussed above, this proposed adjustment should be rejected as well. There is nothing in the record to suggest or support that the M&S inventory balances the Company has proposed to include in rate base are imprudent or unreasonable. The Commission should reject this recommendation.

III. CASH WORKING CAPITAL

Q. PLEASE DESCRIBE MR. KOLLEN'S PROPOSAL REGARDING CASH WORKING CAPITAL.

A. Mr. Kollen recommends that Duke Energy Kentucky's cash working capital should be set at $0 absent the Company filing a lead/lag study because the 1/8th O&M methodology the Company used to calculate cash working capital is "outdated and inaccurate." He is recommending a reduction in the Company's proposed revenue requirement of $1.242 million as a result of this recommendation.

Q. MR. KOLLEN ASSERTS ON PAGE 13 OF HIS TESTIMONY THAT THIS ISSUE IS A "CASE OF FIRST IMPRESSION FOR [DUKE ENERGY KENTUCKY]." IS HE CORRECT?

A. No. Mr. Kollen provided testimony as a witness for the Attorney General in the Company's most recent natural gas and electric base rate cases. The Company's proposal to use rate base in lieu of capitalization as the basis for establishing its revenue requirement in this case is identical to what was proposed in its 2018 natural gas base rate case. Similarly, the proposal to use the 1/8th O&M method for calculating cash working capital in this case is identical to what was proposed in that base rate case.

Mr. Kollen's suggestion that utilizing rate base in lieu of capitalization is a case of first impression for Duke Energy Kentucky is not accurate. It is also a fact that a number of utilities subject to the jurisdiction of this Commission have used rate base for establishing a test year revenue requirement in recent base rate cases. Atmos Energy, Columbia Gas of Kentucky, and Delta Natural Gas have all used rate base as the basis for computing cost of service since at least 2002.[2] Additionally, Duke Energy used rate base as the basis for computing cost of service in its last natural gas base rate case filed in 2019.[3] In all of these cases, the Commission approved rates that provided a return on rate base rather than capitalization. Mr. Kollen has been a witness for the Attorney General in some of these cases; so, it is hardly a case of first impression for this Commission or for Mr. Kollen.

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[2] *See e.g., In the Matter of the Application of Columbia Gas of Kentucky, Inc. For an Adjustment of Rates,* Case No. 2007-0008 Ky.P.S.C. Order (August 29, 2007); *In the Matter of the Application of Atmos Energy Corporation for an Adjustment of Rates,* Case No. 2009-00354 KyP.S.C. Order (March 12, 2010); *In the Matter of the Application of Atmos Energy Corporation for an Adjustment of Rates and Tariff Modifications,* Case No 2013-00148 Ky.P.S.C. Order (April 22, 2014); *In the Matter of the Application of Atmos Energy Corporation for an Adjustment of Rates and Tariff Modifications,* Case No. 2015-00343 (Order)(August 4, 2016); and *In the Matter of the Application of Delta Natural Gas Company, Inc. for an Adjustment of Rates,* Case No. 2010-00116 Ky.P.S.C. (Order)(October 21, 2010).

[3] *In the Matter of the Electronic Application of Duke Energy Kentucky, Inc for Authority to 1) Adjust Natural Gas Rates; 2) Approval of a Decoupling Mechanism; 3) Approval of new Tariffs; 4) And for All Other Required Approvals, Waivers, and Relief,* Case No. 2018-00261 Ky.P.S.C. (Order)(March 27, 2019).

Q. DO YOU AGREE WITH MR. KOLLEN'S RECOMMENDATION THAT DUKE ENERGY KENTUCKY'S CASH WORKING CAPITAL SHOULD BE SET AT $0?

A. No, I do not. It is a fact that the 1/8th O&M methodology for calculating cash working capital has been accepted by this Commission in previous proceedings. In fact, prior witnesses for the Attorney General have acknowledged the Commission's practice of using the 1/8th O&M method. As noted by Robert J. Henkes, testifying for the Attorney General in Case No. 2009-00202, a prior Duke Energy Kentucky natural gas base rate case, "...it is my understanding that the Commission has *consistently allowed* [Duke Energy Kentucky's] cash working capital to be determined based on this modified 1/8th method."[4] (emphasis added)

Duke Energy Kentucky followed this longstanding precedent in developing its estimate of cash working capital as it has done in every electric and natural gas base rate case over many years.

Q. IS IT FAIR TO SAY THAT THE COMMISSION CONTINUES TO ALLOW UTILITIES TO USE THE 1/8TH O&M METHOD FOR CALCULATING CASH WORKING CAPITAL?

A. Yes. Within the last year, the Commission approved the Company's new base rates for natural gas service. The base rates were developed, in part, using the 1/8th O&M method for determining the cash working capital component of rate base.

[4] *In re Application of Duke Energy Kentucky, Inc. for an Adjustment of Gas Rates,* Case No. 2009-00202 (Direct Testimony of Robert J. Henkes, p. 18)(October 12, 2009).

Q. MR. KOLLEN DISMISSES THE NOTION THAT THE COMMISSION EITHER AFFIRMED OR REJECTED THE USE OF THE 1/8TH O&M METHOD IN THAT CASE BECAUSE THE CASE WAS SETTLED. IS THAT A RELEVANT CONCERN?

A. No. The settlement reached in the prior natural gas base rate case was exclusively between the Company and the Attorney General. The Commission held a full hearing and made a decision on whether the settlement was reasonable or not. Ultimately, the Commission made minor modifications to the settlement agreement, reflecting the fact that it weighed all of the evidence in the case, including the various components of rate base. Mr. Kollen is free to argue that the Attorney General neither affirmed nor rejected the calculation of cash working capital in the prior natural gas base rate case, but the fact that the Commission fully adjudicated the Company's base rate case does indicate that it considered this issue, among the many other issues involved in reaching a decision in that case, and approved a rate base that included cash working capital estimated using the 1/8th O&M method.

Q. IF THE COMMISSION AGREES WITH MR. KOLLEN'S ARGUMENT, SHOULD THE COMMISSION IMPOSE SUCH A REQUIREMENT IN THIS CASE?

A. No. Although I am not an attorney, in my role as Director of Rates and Regulatory Planning, I am familiar with the Commission's regulations and procedures. I am not aware of any rule in the Kentucky Administrative Regulations or any law in the Kentucky Revised Statutes that <u>requires</u> a utility to develop a lead/lag study for its estimate of cash working capital. The Commission found the Company's initial application to be fully compliant and issued a notice on September 9, 2019, that there were no deficiencies in the Company's initial application. It would be unfair to the Company to reduce rate base by nearly $15 million because the Company failed to comply with a requirement that does not exist, and that in practice has been historically accepted by the Commission.

A utility is guided by two principles when making regulatory filings. One obvious principle is to simply comply with the codified rules and regulations. The second principle guiding such filings is Commission precedent. Commission precedent for establishing Duke Energy Kentucky's cash working capital has, for many years, been to use the $1/8^{th}$ O&M method. It would be unfair to change the rules or to establish new precedent during the pendency of this case.

Therefore, if the Commission ultimately agrees to reject its longstanding precedent of using the $1/8^{th}$ O&M method in favor of any other method for computing a cash working capital allowance in rate base, it should only be implemented prospectively and not in this instant proceeding.

Q. DO YOU HAVE ANY COMMENTS ABOUT MR. KOLLEN'S REFERENCES TO RECENT REQUESTS BY SOME OF DUKE ENERGY KENTUCKY'S AFFILIATES?

A. Although the ratemaking policies and practices in the jurisdictions of Duke Energy Kentucky's affiliates differ in many ways from those of the Kentucky Public Service Commission, Mr. Kollen argues that the Commission should disregard its own policies and practices and adopt, for this particular issue, the ratemaking policies and practices used by other state regulators. As Mr. Kollen is surely aware, each regulatory body asserts its jurisdiction over its own regulated utilities in different ways and are not bound by the ratemaking policies and procedures applied by their counterparts.

As Mr. Kollen notes in his testimony, in recent applications by Duke Energy Indiana and Duke Energy Ohio, these companies included $0 for cash working capital in their rate case filings. Mr. Kollen apparently infers from this that Duke Energy Kentucky's affiliates believe that $0 cash working capital is reasonable. Another explanation for the proposals by Duke Energy Indiana and Duke Energy Ohio is that their regulators do have prescriptive rules and/or precedent for the calculation of cash working capital. For example, the Ohio Administrative Code includes a legal requirement that utilities seeking an allowance for cash working capital *must* submit a lead/lag study supporting the request. Ohio law does not allow for the use of the 1/8th O&M method for calculating cash working capital for major utilities. Contrary to Mr. Kollen's inference, the fact that Duke Energy Ohio did not propose to use the 1/8th O&M method for its retail rate case had nothing to do with whether that methodology was reasonable – the choice not to use the 1/8th O&M method was made simply to comply with Ohio law. Nothing in Kentucky's statutes or the Commission's regulations prescribes how utilities should estimate their cash working capital requirements.

Although Mr. Kollen provides examples of how certain other Duke Energy Kentucky affiliates estimate cash working capital, he neglects to mention that the same affiliates use the 1/8th O&M method for calculating their cash working capital allowance in calculating their wholesale transmission revenue requirement under FERC-approved formula rates.[5]

Q. SHOULD THE COMMISSION ADJUST DUKE ENERGY KENTUCKY'S REVENUE REQUIREMENT TO SET ITS WORKING CAPITAL TO $0?

A. No. The Commission should reject this recommendation. There is no reason for the Commission to change precedent in this instance. The 1/8th O&M method has long been considered a reasonable approximation of working capital and has been approved by this Commission to establish the Company's rates in the past. Commission precedence on this issue allows for the streamlining of a complex and lengthy component of ratemaking and should be upheld. The Company believes this method should continue to be used. Reducing the Company's rate base because the Company relied upon and followed prior Commission precedent and regulations by using the 1/8th O&M method, and did not anticipate a change in rate case filing requirements, would be unreasonable and punitive.

IV. RATE CASE EXPENSE

Q. PLEASE DESCRIBE MR. KOLLEN'S RECOMMENDATION REGARDING INCLUDING THE REGULATORY ASSET FOR RATE CASE EXPENSE IN THE COMPANY'S TEST YEAR RATE BASE?

A. Mr. Kollen opposes including the Company's regulatory asset for rate case expense in rate base and recommends a reduction in the Company's proposed revenue requirement of $0.059 million.

[5] Duke Energy Indiana's FERC-approved formula rate for wholesale transmission service under Attachment O of the MISO Open Access Transmission Tariff and Duke Energy Ohio/Duke Energy Kentucky's FERC-approved wholesale transmission formula rate under Attachment H-22 of PJM's Open Access Transmission Tariff.

Q. DOES MR. KOLLEN EXPLAIN WHY HE BELIEVES THE COMPANY SHOULD NOT BE ALLOWED TO INCLUDE THIS REGULATORY ASSET IN RATE BASE?

A. He offers several misguided reasons for his proposal. First, he again argues that Duke Energy Kentucky be bound to the ratemaking policies and practices of another regulator, namely, the Indiana Utility Regulatory Commission (IURC). In his opinion, the fact that Duke Energy Kentucky's affiliate Duke Energy Indiana did not propose to include this regulatory asset in rate base means that this Commission should reject its own precedent in allowing this regulatory asset in rate base. Second, he argues that a utility's incremental costs to develop, file, and litigate rate cases exclusively benefit a utility's shareholders and, therefore, the utility should not receive the benefit of a return on the regulatory asset for rate case expense. Lastly, he argues that, because individual components of rate base decline each year, customers will never benefit from the reduction in rate base from this individual rate base component.

Q. IS IT REASONABLE FOR THE KENTUCKY PUBLIC SERVICE COMMISSION TO BE BOUND BY THE REGULATIONS AND PRECEDENTS OF OTHER REGULATORS, SUCH AS THE IURC?

A. No. Mr. Kollen selectively invokes one component of Duke Energy Indiana's filing to argue that Duke Energy Kentucky should be subject to the same proposal without any discussion of what the rules, regulations, or precedent for such treatment is in Indiana as compared to Kentucky. A more apt precedent for the Commission to consider is its own precedent. In a very recent case, Atmos Energy was allowed to include in rate base a regulatory asset for rate case expense. In Case No. 2018-00281, the Commission approved Atmos Energy's proposed rate base that included a regulatory asset for rate case expense[6]. No witness for the Attorney General in that proceeding, including Mr. Kollen, filed any testimony objecting to the inclusion of this regulatory asset. It is true that Mr. Kollen objected to the inclusion of this regulatory asset in a previous case involving Atmos Energy, Case No. 2015-00343, but the Commission's order in that case ultimately approved a rate base that included a regulatory asset for rate case expense.

Mr. Kollen's recommendation for the Commission to ignore its own precedent in favor of precedent in other jurisdictions should be rejected by the Commission. The Kentucky Public Service Commission has its own rules, regulations, and precedents to rely on; so, there is no reason for it to impose regulatory frameworks from other jurisdictions on its own regulated utilities. Mr. Kollen is attempting to cherry pick various policies and practices from other jurisdictions that support his position.

Q. DO YOU AGREE WITH MR. KOLLEN'S ASSERTION THAT ONLY SHAREHOLDERS BENEFIT FROM THE COSTS INCURRED TO DEVELOP, FILE, AND LITIGATE RATE CASES?

A. No. I do not. First of all, rate cases involve many elements besides the revenue requirement. Utilities often include proposals to modify rate design, introduce new programs for safety and reliability, introduce new major capital projects, adjust

[6] *In the Matter of the Electronic Application of Atmos Energy Corporation for an Adjustment of Rates*, Case No. 2018-00281 Ky.P.S.C. Order (May 7, 2019).

depreciation rates, adjust returns on capital, introduce profit sharing mechanisms, etc. The notion that filing a rate case is exclusively for the benefit of shareholders is wrong and should be rejected by the Commission. Indeed, in this case, the Company proposed several initiatives that are beneficial to customers, such as its Green Source Advantage program, fee-free payment proposal, and electric vehicle incentives.

Utilities subject to rate regulation *must* obtain Commission approval to modify retail base rates. It has long been established that utilities are allowed an opportunity to recover their costs of doing business including a fair rate of return. Occasionally, utilities determine that existing rates are not sufficient to meet that legal standard and, consequently, utilities file applications to adjust base rates. As mentioned above, such applications are often accompanied with other important components that benefit all stakeholders.

Mr. Kollen's testimony that only shareholders benefit from this activity belies the fact that utilities are subject to regulation and can only adjust rates when rate filings are approved by the regulator - these costs are undeniably unavoidable costs of doing business. In fact, contrary to Mr. Kollen's testimony, the incurrence of rate case expenses do benefit customers because, without periodically filing rate cases, utilities may not have sufficient funding to provide safe and reliable utility service, may not have an opportunity to reflect contemporary costs of service and rate design principles, and may not be able to effectively introduce new programs and rate mechanisms that directly benefit customers.

Q. IS MR. KOLLEN'S ARGUMENT ABOUT THE IMPACT OF AMORTIZING THE RATE CASE EXPENSE REGULATORY ASSET A REASONABLE BASIS FOR EXCLUDING IT FROM RATE BASE?

A. No. As Mr. Kollen is aware, nearly all components of rate base are subject to depreciation or amortization and, individually, the value of each component declines over time as depreciation and/or amortization expense is recorded against the asset. For example, a typical substation is subject to depreciation; so, the thirteen-month average of the undepreciated value of that asset during the forecasted test year is included in rate base. In the course of the next five years, that individual asset will continue to depreciate such that it will have a smaller undepreciated balance in the future than it does during the test year. The ratemaking formula in Kentucky (and in most jurisdictions) uses a snapshot of rate base for a particular period of time as the basis for setting rates knowing that a utility's rate base is not comprised of just one asset. Certain factors, such as depreciation and amortization, will drive rate base down over time and other factors, new capital spending, changes in tax laws, amortization of accumulated deferred income taxes, etc., will drive rate base up.

Mr. Kollen's suggestion, taken to its extreme, is that any asset that will be worth less in the future because of amortization (or depreciation) should be excluded from rate base. Such a regulatory model would serve Mr. Kollen's objective of reducing the Company's revenue requirement; however, it would be at the expense of abandoning decades of traditional regulatory principles.

Q. MR. KOLLEN SUPPORTS HIS RECOMMENDATION FOR EXCLUDING THE RATE CASE REGULATORY ASSET FROM RATE BASE BY SUGGESTING THAT THERE SHOULD BE A 'SHARING' OF THE RATE CASE EXPENSE BETWEEN CUSTOMERS AND SHAREHOLDERS. IS MR. KOLLEN'S RATIONALE REASONABLE?

A. No. Following Mr. Kollen's logic, the utility should not recover a return on any of its investment but only a return of the investment. The decades' old legal standard in utility regulation is that shareholders should be fairly compensated for their investment in providing utility service. The costs incurred to develop, file, and litigate base rate cases is essentially an investment no different than any capital investment and, consequently, shareholders should be compensated for the use of their money. It would be nonsensical to suggest that shareholders receive zero return on an investment such as a new substation but that is essentially what Mr. Kollen is suggesting for the expenditure being made by shareholders for rate case expenses.

Q. DO YOU HAVE A RECOMMENDATION REGARDING WHETHER THE COMMISSION SHOULD CONSIDER MR. KOLLEN'S RECOMMENDATION TO EXCLUDE THE RATE CASE REGULATORY ASSET FROM RATE BASE?

A. The Commission should ignore all of Mr. Kollen's testimony on this issue. He attempts to distract the Commission from its own precedent by asking it to adopt the policies and practices of other jurisdictions rather than consider its own precedent of allowing a return on this regulatory asset. His suggestion that customers do not benefit from rate case filings is untrue, biased and unfair. And, finally, his concern that base rates do not reset quickly enough to capture the declining unamortized value of the rate case expense regulatory asset is a red herring because the fact is that all assets included in currently approved rate base decrease in value over time but, without annually updating base rates (*i.e.*, a formula rate), will result in positive or negative regulatory lag.

V. DEPRECIATION EXPENSE

Q. PLEASE DESCRIBE MR. KOLLEN'S RECOMMENDATIONS REGARDING RECOVERY OF THE COST OF THE DEPRECIATION STUDY INCLUDED IN THE COMPANY'S APPLICATION.

A. Although the Commission's filing requirements for rate case applications include the filing of its most current depreciation study, Mr. Kollen takes exception to the timing of the Company's depreciation study filed in this case and recommends excluding $60,000 from the Company's rate case regulatory asset and eliminating approximately $12,000 per year of revenue requirement (based on the five-year amortization period for the rate case regulatory asset proposed in this case).

Q. IS MR. KOLLEN'S RECOMMENDATION REASONABLE?

A. No. There is no provision in the Kentucky statutes or the Commission's regulations that would suggest that the Company should not update its depreciation study no matter how much time has elapsed between rate cases. Mr. Kollen's judgment that two years is not long enough is not supported in Kentucky law and he has no basis for making this recommendation.

Anticipating a rate case, the Company hired an independent consultant, John Spanos, to update the depreciation rates for Duke Energy Kentucky's electric assets. Mr. Spanos developed rates using the Average Life Group (ALG) method that was approved by the Commission in Case No. 2017-00321. The Company is proposing to apply these updated rates to thirteen-month average plant balances in its test year revenue requirement. There is nothing about that process that is inconsistent with the normal process for filing rate cases in Kentucky.

Q. TO YOUR KNOWLEDGE, HAS THE COMMISSION EVER DISALLOWED FROM RATE CASE EXPENSES THE COST OF CONDUCTING A DEPRECIATION STUDY ON THE GROUNDS THAT ONE WAS PERFORMED TOO SOON AFTER ANOTHER ONE?

A. Not that I am aware of.

Q. ASSUMING THE COMMISSION ACCEPTS MR. KOLLEN'S PROPOSAL TO ELIMINATE THE COST OF THE COMPANY'S DEPRECIATION STUDY ON THE GROUNDS THAT IT WAS PERFORMED TOO SOON AFTER THE MOST RECENT STUDY, DOES THAT HAVE ANY IMPLICATIONS ON OTHER FILING REQUIREMENTS FOR FUTURE RATE CASES?

A. If the Commission does disallow the costs of the depreciation study for those reasons, then Duke Energy Kentucky recommends that the Commission provide instructions for the Company, and all jurisdictional utilities for that matter, as to how much time must elapse before it is appropriate to revise depreciation studies and all other studies that are part of rate case filings. For example, should studies of labor costs, benefits costs, lead/lag studies, only be performed no more than once every so many years. Mr. Kollen's proposal, if adopted, creates uncertainty for Duke Energy Kentucky and all jurisdictional utilities insofar as utilities cannot know, with certainty, whether the cost of studies done as part of a rate case will be recoverable or if there is a time limit on how frequently such studies may be done.

Q. IS THAT THE ONLY ISSUE RAISED BY MR. KOLLEN RELATED TO DEPRECIATION EXPENSE?

A. No. However, Company witness John J. Spanos will address the other issues raised by Mr. Kollen as they related to the test year depreciation expense proposed by the Company.

VI. MAJOR STORM DEFERRAL

Q. PLEASE DESCRIBE MR. COLLINS' TESTIMONY REGARDING THE COMPANY'S REQUEST FOR ACCOUNTING AUTHORITY TO DEFER THE DIFFERENCE BETWEEN ACTUAL STORM COSTS AND THE AMOUNT FOR STORM COSTS INCLUDED IN BASE RATES.

A. Mr. Collins opposes the Company's request primarily on the grounds that, in his view:

a. the use of trackers engages in single-issue ratemaking;

b. trackers eliminate the utility's incentive to control costs;

c. trackers remove all uncertainty with respect to storm costs without regard to the actual level of deviation in the expense; and

d. a level of recovery for storm costs is already included in the Company's financial projections.

Q. SHOULD THE COMMISSION BE CONCERNED THAT THE COMPANY'S PROPOSAL PROMOTES SINGLE-ISSUE RATEMAKING?

A. No. The Company's proposal mirrors similar accounting authority the Commission approved in the Company's most recent electric base rate case. In that case (Case No. 2017-00321), the Commission approved the Company's request to create a deferral mechanism to track the difference between its planned outage O&M costs in a year compared to the amount included in base rates. The Commission also granted authority to allow the Company to record as a deferral the difference between its actual fuel and purchased power costs during forced outages that is not collected via the fuel adjustment rider and the amount included in base rates.

The rationale for seeking the accounting authority is exactly the same for the Company's proposed storm deferral as it was for the planned outage and forced outage deferrals from the prior case. Each of these deferrals relate to discrete cost types that are highly volatile and the incurrence of the costs are outside of the Company's control. The Commission recognized the significance of these deferrals when it approved the requested accounting authority in the prior case, and it can rely on the same rationale for approving the Company's request in this case.

Q. HOW DO YOU RESPOND TO MR. COLLINS' CONCERN THAT APPROVAL OF THIS ACCOUNTING AUTHORITY WILL ELIMINATE THE COMPANY INCENTIVE TO CONTROL COSTS?

A. First, controlling costs, generally, is of utmost importance to the Company but, in the case of storms, the number one priority is restoring service. Mr. Collins' concern about eliminating the incentive to control costs misses the point as it relates to storm costs. The Company's request is only to defer the difference in the costs of major storms above or below the amount in base rates. The costs incurred by the Company during major storm events is almost exclusively related to the restoration of service. While cost control is always a consideration, restoration of service is the primary goal.

During a major storm event, utilities have to weigh the costs of restoration with the fact that customers demand that their electricity be restored as soon as possible. Mr. Collins' insinuation that Duke Energy Kentucky's requested accounting authority might undermine its efforts to control costs during major storm restoration efforts, underappreciates the primacy of the restoration effort itself.

Q. HOW DO YOU RESPOND TO MR. COLLINS' CONCERN THAT THE PROPOSED ACCOUNTING AUTHORITY REMOVES THE COMPANY'S UNCERTAINTY REGARDING STORM COSTS?

A. He is correct. That is the point of the deferral. The deferral ensures that actual costs of storms recovered from customers equals the actual cost of restoration that results from major storms. Without the deferral, the Company's shareholders benefit if the actual storm costs are below the amount in base rates and customers avoid all of the costs of major storms to the extent the costs exceed the amounts included in base rates.

Q. DO YOU AGREE WITH MR. COLLINS' ASSERTION THAT DUKE ENERGY KENTUCKY IS ALREADY PROTECTED FINANCIALLY FOR THE COST OF MAJOR STORMS BECAUSE IT CAN FILE SEPARATE APPLICATIONS FOR ACCOUNTING AUTHORITY AS IT HAS DONE IN THE PAST?

A. It is true that the Company can, and has, sought authority to defer the incremental cost of major storms in the past. In my opinion, however, the Company's proposal here is superior in that it eliminates the need to make additional filings with the Commission which creates an unnecessary burden on both the Company and the Commission (and potentially, intervenors if they object). A particular virtue of the Company's proposal is that it is symmetrical. The deferrals to be made could be a regulatory liability, when the actual storm costs are less than the amount included in base rates, or a regulatory asset when the actual storm cost is higher than the amount included in base rates. A regulatory liability means that Duke Energy Kentucky owes customers because storm costs have been less than the amount recovered in base rates. A regulatory asset means that the Company will recover additional revenue from customers because storm costs have been higher than the amount recovered in base rates.

The ultimate objective of the proposed accounting deferral is to ensure that customers pay no more and no less than the actual cost of restoration resulting from major storms.

VII. REVISED REVENUE REQUIREMENT

Q. HAS THE ATTORNEY GENERAL MADE REVENUE REQUIREMENT ADJUSTMENT RECOMMENDATIONS THAT THE COMPANY ACCEPTS?

A. Yes. There are four adjustments that Mr. Kollen is recommending which the Company is willing to accept. Additionally, there is one adjustment identified by the Company through the course of answering discovery.

Q. PLEASE EXPLAIN.

A. First, as the Company noted in response to discovery question AG-DR-02-005, there was a component of accumulated deferred income taxes (ADIT) that should not have been included in the ADIT offset to rate base. Because this component was a net deferred tax asset, removing this component has the effect of increasing the net ADIT liability balance and therefore reducing rate base. The impact to the Company's requested revenue requirement is a reduction of $0.250 million and the Company agrees to adjust its requested revenue requirement accordingly.

Secondly, Mr. Kollen is recommending that the Company reduce payroll taxes associated with the reduction in short term incentive compensation for earnings related and stock-based incentives that the Company has already excluded from its revenue requirement. The Company is willing to modify its revenue requirement for this adjustment resulting in a lower revenue requirement request of $0.066 million.

Thirdly, Mr. Kollen recommends that the Commission remove from the revenue requirement the development and implementation O&M expenses associated with the Company's Customer Connect program. He further recommends that the Commission should direct the Company to defer these expenses as a regulatory asset. The Company believes its approach to include the costs in base rates is reasonable. However, the Company is willing to accept Mr. Kollen's recommendation only if regulatory asset authority is granted by the Commission to allow the Company to accumulate all actual O&M expenses, including carrying costs, associated with the Customer Connect program incurred (beginning with those incurred during the test period in this case) into a regulatory asset. Once the total actual costs for the project are incurred and the actual amount of the regulatory asset is known, the Company will request recovery in a subsequent rate proceeding. The Company also agrees with Mr. Kollen's recommendation to include this regulatory asset in rate base in that subsequent rate proceeding with an amortization period equal to the service life used for the depreciation rate applied to the capital costs. This adjustment has the effect of reducing the Company's proposed revenue requirement increase by $0.911 million.

Fourth, Mr. Kollen recommends that the Commission exclude Supplemental Executive Retirement Plan (SERP) Expense from the Company's revenue requirement. The Company accepts this adjustment and will modify its revenue requirement. On Schedule D-2.29 in the Company's filing, a proforma adjustment was made to eliminate pension expense related to employees who participate in both a defined benefit pension program and a 401K company match program. This adjustment was made to be consistent with Commission rulings in recent cases, Case No. 2017-00321 and 2018-00261. However, the Company recognizes that in this adjustment, only the qualified pension expense was removed. The Company should have also removed the non-qualified pension expense or SERP Expense. This adjustment reduces the Company's proposed revenue requirement by $0.122 million.

The last adjustment relates to the Company's transmission expense. As the Company noted in response to discovery question AG-DR-02-032(e), the Company received refunds associated with Regional Transmission Expansion Planning (RTEP) expenses incurred in May and June of 2018 totaling $0.260 million that it inadvertently did not include in its test period revenue requirement. As Mr. Wathen discusses further in his rebuttal testimony, the Company started including RTEP expenses in base rates effective May 2018. The refunds the Company received were for RTEP expenses paid. Therefore, any refunds received in May and June of 2018 should have been reflected in the test period revenue requirement in this case because that was the first time customers started paying RTEP expenses. All RTEP expenses prior to that time were not reflected in the Company's rates and were thus paid for by the Company's shareholders. The Company proposes to amortize this credit over five years which results in a decrease in its proposed revenue requirement of $0.052 million as a result of this omission.

Q. ARE THERE OTHER DISCREPANCIES IN THE TEST PERIOD REVENUE REQUIREMENT THAT THE COMPANY NOTED IN THE COURSE OF RESPONDING TO DISCOVERY IN THIS CASE?

A. Yes. As noted in response to discovery question AG-DR-01-039, the Company inadvertently excluded $0.915 million of costs included in Account 931008. The amounts recorded to this account represent the return on DEBS assets. As further explained by Duke Energy Kentucky witness Jeff Setser, Mr. Kollen proposed an adjustment to remove the return on DEBS assets from the Company's revenue requirement. As Mr. Setser discusses, the Company disagrees that the return on DEBS assets should be excluded from the revenue requirement. However, even if the Commission agrees with the AG on this issue, because of this inadvertent exclusion by the Company, there is no adjustment to make. Because nothing was included in the revenue requirement to begin with, Mr. Kollen's recommendation to remove the return on DEBS assets is akin to double counting.

Q. IS THE COMPANY PROPOSING TO ADJUST ITS REVENUE REQUIREMENT REQUEST TO INCLUDE THESE COSTS?

A. No. This was a mistake on the Company's part and would have the effect of increasing the revenue requirement. In the interest of limiting the number of contested issues in the case, the Company is forgoing making this correction to its proposed test year revenue requirement.

Q. PLEASE SUMMARIZE THE COMPANY'S REVISED REVENUE REQUIREMENT BASED ON THE CHANGES DISCUSSED IN YOUR REBUTTAL TESTIMONY.

A. The following table reflects the Company's revised revenue requirement increase based on my testimony and assumes the Commission grants deferral authority associated with the Customer Connect O&M Expenses.

Line No.	Summary	Impact to Revenue Requirement
1	**Duke Energy Kentucky Initial Request**	$45,634,448
2	ADIT Adjustment	(250,336)
3	Payroll taxes associated with earnings and stock based compensation	(65,602)
4	Customer Connect O&M Expenses	(910,599)
5	SERP Expense	(121,759)
6	Refunds associated with RTEP expenses included in base rates	(52,106)
7	**Total Adjustments to Company's Proposed Revenue Requirement**	$ (1,400,402)
8	Adjustments to cash working capital as a result of above changes*	(11,217)
9	**Duke Energy Kentucky Revised Revenue Requirement Request**	$44,222,829

*The Company uses the 1/8th O&M method to calculate cash working capital. The adjustments on lines 4, 5 and 6 reduce O&M and therefore reduces cash working capital.

VIII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

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

The undersigned, Sarah E. Lawler, Director Rates & Regulatory Planning, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing rebuttal testimony and that it is true and correct to the best of her knowledge, information and belief.

Sarah E. Lawler Affiant

Subscribed and sworn to before me by Sarah E. Lawler on this 10th day of January, 2020.

NOTARY PUBLIC

My Commission Expires: July 8, 2022

NOTARY PUBLIC STATE OF OHIO

E. MINNA ROLFES-ADKINS
Notary Public, State of Ohio
My Commission Expires
July 8, 2022

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	))))))))	Case No. 2019-00271

REBUTTAL TESTIMONY OF

ROGER A. MORIN, PhD

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

January 31, 2020

TABLE OF CONTENTS

PAGE

ATTACHMENTS:

Attachment RAM-Rebuttal-1	DCF Growth Rate Analysis
Attachment RAM-Rebuttal-2	Corrected DCF Return on Equity
Attachment RAM-Rebuttal-3	DCF Analysis Value Line Growth Rates
Attachment RAM-Rebuttal-4	DCF Analysis Analysts' Growth Rates

I. INTRODUCTION AND PURPOSE

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

A. My name is Mr. 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 was 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. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING ON BEHALF OF DUKE ENERGY KENTUCKY, INC (DUKE ENERGY KENTUCKY OR "COMPANY")?

A. Yes, I did.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I have been asked to respond to the cost of capital testimony of Mr. Baudino on behalf of the Kentucky Office of The Attorney General (AG). I also provide an updated recommendation in view of appreciable changes that have occurred in capital market conditions.

II. DISCUSSION

A. Summary of Criticisms to Mr. Baudino's Testimony

Q. PLEASE SUMMARIZE MR. BAUDINO'S RATE OF RETURN RECOMMENDATION.

A. Mr. Baudino recommends a return on equity (ROE) of 9.0% for Duke Energy Kentucky, which I believe would be among the lowest authorized return in the electric utility industry. In determining the cost of equity, Mr. Baudino applies a Discounted Cash Flow (DCF) analysis to a group of 20 electric utilities. This study, summarized on page 22 of his testimony, produces a result of 8.0% - 9.5% using average growth rates and 7.8% - 9.1% using medians. Mr. Baudino also performs a Capital Asset Pricing Model (CAPM) analysis, although he does not rely on the results of this analysis. The CAPM analysis, summarized on page 29 lines 11-12 of his testimony, produces a result of 7.7% - 8.0% using prospective market risk premiums and 6.0% - 7.1% using historical market risk premiums. All the ROE results are summarized on Table 1 page 30.

Based on his DCF analysis, Mr. Baudino concludes that Duke Energy Kentucky's cost of equity is lies in a range of 8.5% - 9.5% and adopts the midpoint of 9.0% as his final recommendation.

Q. WHAT IS YOUR FIRST GENERAL REACTION TO MR. BAUDINO'S COST OF COMMON EQUITY RECOMMENDATION?

A. My general reaction to his recommendation, before I engage in a more technical critique, is that there are two major flaws in Mr. Baudino's testimony. First, Mr. Baudino's recommended 9.0% ROE for Duke Energy Kentucky lies outside the zone of currently authorized ROEs for electric utilities in the United States which average 9.6% as he himself states on page 31 lines 2-4 of his testimony. Mr. Baudino's recommended reduction of the Company's ROE down to 9.0%, if adopted, would result in one of the lowest ROE authorized in the utility industry. Mr. Baudino's low ROE recommendation would cause adverse consequences on the Company's creditworthiness, its financial integrity, the Company's capital raising ability, and ultimately its customers. Moreover, Mr. Baudino's recommended ROE lies below the zone of his own comparable companies authorized and expected ROEs. These facts provide clear proof that his ROE recommendation for Duke Energy Kentucky is too low.

Q. WHAT IS YOUR SECOND GENERAL REACTION TO MR. BAUDINO'S COST OF COMMON EQUITY RECOMMENDATION?

A. My second general reaction to Mr. Baudino's testimony, is that his recommendation of 9.0% rests exclusively on the results of a DCF analysis. Mr. Baudino has put all of his eggs in the DCF basket which causes him to recommend returns that are well below investors' required returns. This narrow approach stands in sharp contrast with the cost of capital estimation practices of investment analysts, finance experts, corporate analysts, and finance professionals who rely on a variety of methodologies. His CAPM check on the DCF result, on which he places little, if any, weight is also flawed, as I discuss later. Mr. Baudino employs understated model inputs in his analyses, which cause him to recommend returns that are below investors' required returns.

Q. IS MR. BAUDINO'S LOW RECOMMENDED ROE APPROPRIATE AT THIS TIME?

A. No. Mr. Baudino's recommended ROE of 9.0 %, which would be among the lowest authorized ROE in the country, is untimely and contrary to customers' best interests to receive reliable and reasonably-priced service. As I discussed in my direct testimony, if Duke Energy Kentucky's authorized ROE is set too low, it will ultimately increase costs for Duke Energy Kentucky's customers. The Commonwealth of Kentucky Public Service Commission's (Commission) approval of the authorized ROE of 9.8% that I have recommended, will buttress these goals and provide measurable benefits to Duke Energy Kentucky customers.

Maintaining the Company's financial viability and creditworthiness decreases borrowing costs, improves access to capital and the availability of longer-term debt maturities, and enables the Company to absorb any negative volatility in its financial performance. Moreover, maintaining the Company's financial viability will have beneficial long-term cost implications for the Company and its customers as the Company re-finances existing debt, issues new capital and enters into new contractual arrangements. Clearly, Duke Energy Kentucky's customers have a vested interest in a strong financial position for the utility. The interests of customers and shareholders are consistent, not mutually exclusive. They both benefit from a financially sound utility.

Q. WHAT ARE THE BASIC CONCLUSIONS OF YOUR REBUTTAL TESTIMONY TO MR. BAUDINO'S COST OF EQUITY TESTIMONY?

A. While I agree with several of Mr. Baudino's procedures and methodologies, as I will demonstrate below, Mr. Baudino understates the appropriate ROE for Duke Energy Kentucky by a minimum of 60 basis points (1.2%), which would bring his recommended ROE to a minimum of 9.6% which is close to my recommended ROE. If Mr. Baudino's various results are amended to reflect proper data inputs to the financial models, Mr. Baudino's revised ROE recommendation would be quite close to my own recommendation.

Q. PLEASE SUMMARIZE YOUR COMMENTS ON MR. BAUDINO'S TESTIMONY.

A. I stress from the start that I agree with several of Mr. Baudino's views and procedures in estimating Duke Energy Kentucky's cost of equity. Mr. Baudino's procedures and methodologies are generally sound and in keeping with the practices of finance professionals. For example, I agree with: (1) the companies in his comparable group; (ii) the use of analysts' growth forecasts as proxies for expected growth in the DCF model; (iii) the beta estimates in the CAPM analysis; (iv) some of his market risk premium estimates in the CAPM analysis, and (v) his capital structure recommendation. My disagreements center more on some of the appropriate data inputs to the DCF and CAPM models.

Specifically, I disagree with Mr. Baudino on the following grounds: (1) an understated dividend yield component in the DCF model, (2) the absence of a flotation cost adjustment; (3) the risk-free rate proxy in the CAPM, (4) part of his market risk premium estimate in the CAPM, (5) the failure to employ the empirical version of the CAPM in keeping with the vast literature on the subject, and (6) failure to account for Duke Energy Kentucky's high relative risks. I also conclude that his criticisms of my testimony are unfounded. I shall now address each of those issues in turn.

Q. WHAT ARE THE BASIC CONCLUSIONS OF YOUR REBUTTAL TO MR. BAUDINO'S COST OF EQUITY TESTIMONY?

A. Mr. Baudino understates Duke Energy Kentucky's cost of common equity. A proper application of cost of capital methodologies would give results higher than those that he obtained.

B. Specific criticisms of Mr. Baudino's Testimony

Q. PLEASE SUMMARIZE YOUR SPECIFIC CRITICISMS OF MR. BAUDINO'S TESTIMONY.

A. I have a number of criticisms of Mr. Baudino's testimony, as follows:

1. Return Recommendation Outside the Mainstream. As succinctly stated above, Mr. Baudino's recommended ROE is outside the zone of currently authorized ROEs for utilities in the United States and that of his own sample of companies. The average authorized ROE in the electric utility industry in 2019 as reported in the Regulatory Research Associates quarterly review June 2019 edition is 9.6%. The currently authorized returns for Mr. Baudino's twenty peer companies average nearly 10%, and the expected returns for these companies from Mr. Baudino's own Value Line data are at least 10.3%. These authorized returns exceed Mr. Baudino's recommended return of 9.0% for Duke Energy Kentucky.

2. Understated Dividend Yield. Mr. Baudino's dividend yield component is understated because it is not consistent with the annual form of the DCF model. It is inappropriate to increase the dividend yield by adding one-half the future growth rate to the spot dividend yield. The appropriate manner of computing the expected dividend yield when using the plain vanilla annual DCF model is to add the full growth rate rather than one-half the growth rate. This adjustment also allows for the failure of the annual DCF model to allow for the quarterly timing of dividend payments. In short, Mr. Baudino's DCF results are understated by some 10 basis points (*i.e.*, 0.10%) alone related to this single flaw.

3. DCF Dividend Yield and Flotation Costs. Mr. Baudino's dividend yield component is understated because it does not allow for flotation costs and, as a result, a legitimate expense is left unrecovered and his ROE results are understated by an additional 20 basis points.

4. DCF Growth Rates. While I agree with Mr. Baudino's reliance on analyst <u>earnings</u> growth forecasts as proxies for the growth component of the DCF model, I disagree with the use of dividend growth forecasts in view of the scarcity of such forecasts. Moreover, as discussed in my direct testimony the empirical finance literature has demonstrated that consensus analysts' <u>earnings</u> growth forecasts (i) are reflected in stock prices, (ii) possess a high explanatory power of equity values, and (iii) are used by investors.

5. CAPM Risk-Free Rate. Mr. Baudino has relied on an inappropriate risk-free rate proxy in implementing the CAPM, understating those results by close to 200 basis points (2.0%).

6. CAPM Market Risk Premium (MRP). Two of Mr. Baudino's four estimates of the MRP are understated.

7. CAPM versus the Empirical CAPM (ECAPM). The basic version of the CAPM used by Mr. Baudino understates the Company's cost of equity for electric utilities by 50 basis points.

8. Risk Adjustment. Mr. Baudino did not adjust his recommended ROE upward to reflect Duke Energy Kentucky's greater than average risk on account of its very small relative size, its high construction program relative to its small size, and its highly concentrated generation portfolio. Such a required adjustment would raise his ROE recommendation significantly.

I shall now discuss each criticism in turn as well as respond to Mr. Baudino's criticisms of my testimony which are largely unfounded.

C. Mr. Baudino's Return Recommendation Is Outside The Mainstream

Q. ARE ALLOWED RETURNS OF ELECTRIC UTILITIES IMPORTANT DETERMINANTS OF INVESTOR GROWTH PERCEPTIONS AND INVESTOR EXPECTED RETURNS?

A. Yes, they are. Allowed returns, while certainly not a precise indication of a company's cost of equity capital, are nevertheless important determinants of investor growth perceptions and investor expected returns. They also serve to provide some perspective on the validity and reasonableness of Mr. Baudino's recommendation.

Q. HOW DOES MR. BAUDINO'S RECOMMENDED ROE COMPARE WITH CURRENTLY ALLOWED ROES IN THE INDUSTRY?

A. Mr. Baudino's recommended ROE of 9.0% for Duke Energy Kentucky is outside the mainstream for electric utilities. The average authorized ROE in the electric utility industry as reported by Regulatory Research Associates (S&P Global Intelligence) in its most recent survey of regulatory decisions in 2019 is 9.6%. Moreover, as shown on Table 1 and according to Value Line, the average authorized ROE for the electric utilities in Mr. Baudino's own peer group is shown in Column 1 is 9.8%, and (ii) the average expected ROE for these electric utilities for the long-term is 10.0%. These allowed and expected ROEs substantially exceed Mr. Baudino's recommended return on equity for Duke Energy Kentucky of 9.0%.

In short, Mr. Baudino's recommendation is outside the mainstream of the allowed rates of return that were current during the period in which Mr. Baudino performed his analysis and lies outside the zone of recently authorized returns for electric utilities and for Mr. Baudino's own sample of companies.

Unreasonable rate treatment for a utility, if implemented, may have serious public policy implications and repercussions that are not mentioned in Mr. Baudino's testimony. For example, the quality of regulation and the reasonableness of authorized ROEs clearly have implications for regulatory climate, economic development and job creation in a given territory. The consistency of regulation in a given jurisdiction has similar implications. I believe that Mr. Baudino's recommended return has negative implications on these grounds and is not consistent with the economic well-being of the Commonwealth of Kentucky. It certainly provides a disincentive to investment in Kentucky.

Table 1. Allowed And Expected Returns

		Expected ROE	Allowed ROE
		(1)	(2)
1	Alliant Energy Corporation (NYSE-LNT)	10.0%	10.0%
2	Ameren Corporation (NYSE-AEE)	10.5%	9.3%
3	Avista Corp (NYSE-AVA)	8.0%	9.5%
4	Black Hills	9.5%	9.4%
5	CenterPoint Energy	9.5%	10.2%
6	Chesapeake Utilities	9.5%	NA
7	CMS Energy Corporation (NYSE-CMS)	13.5%	10.0%
8	Consolidated Edison, Inc. (NYSE-ED)	8.5%	9.0%
9	Dominion Energy Inc. (NYSE-D)	13.0%	10.9%
10	DTE Energy	9.5%	10.1%
11	Duke Energy Corporation (NYSE-DUK)	8.5%	10.2%
12	Eversource Energy (NYSE-ES)	9.0%	9.6%
13	Exelon Corporation (NYSE-EXC)	9.0%	9.6%
14	Fortis	6.5%	9.3%
15	MGE Energy, Inc. (NYSE-MGEE)	10.5%	9.8%
16	NorthWestern Corporation (NYSE-NWE)	9.0%	9.7%
17	Public Service & Enterprise	11.0%	9.6%
18	Sempra Energy (NYSE-SRE)	12.0%	10.2%
19	WEC Energy Group (NYSE-WEC)	12.0%	9.4%
20	Xcel Energy Inc. (NYSE-XEL)	11.0%	9.6%
	AVERAGE	**10.0%**	**9.8%**

Source: Value Line 2018.

D. Understand Dividend Yield

Q. DO YOU HAVE ANY COMMENT ON MR. BAUDINO'S DIVIDEND YIELD CALCULATION IN THE DCF ANALYSIS?

Yes. I disagree with Mr. Baudino's dividend yield calculation on page 23 lines 9-10). Mr. Baudino multiplies the spot dividend yield by one plus one half the expected growth rate (1 + 0.5g) rather than the standard one plus the expected growth rate (1 + g). Mr. Baudino's deviation from the standard methodology understates the return expected by the investor.

The fundamental assumption of the annual DCF model used by Mr. Baudino is that dividends are received annually at the end of each year and that the first dividend is to be received one year from now. Thus, the appropriate dividend to use in a DCF model is the full prospective dividend to be received at the end of the year. Instead, Mr. Baudino calculates the first dividend by multiplying the current dividend by one plus one-half the growth rate (1 + 0.5g) instead of multiplying by one plus the growth rate (1 + g). Since the appropriate dividend to use in a DCF model is the prospective dividend one year from now rather than the dividend one-half year from now, Mr. Baudino's approach understates the proper dividend yield.

Mr. Baudino's use of the wrong methodology creates a downward bias in its dividend yield component, and causing it to underestimate the cost of equity by approximately 12 basis points. For example, for a spot dividend yield of 4% and a growth rate of 6%, Mr. Baudino's estimated dividend yield is 4%(1 + .06/2) = 4.12%. The correct dividend yield to employ is 4%(1 + .06) = 4.24%, which is 12 basis points higher. Thus, failure by Mr. Baudino in its formula to recognize the quarterly nature of dividend payments understates the cost of equity capital by 12 basis points.

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

E. DCF Dividend Yield and Flotation Costs

Q. IN YOUR DIRECT TESTIMONY, YOU STATED THAT THE RETURN ON EQUITY SHOULD BE ADJUSTED TO INCLUDE AN ALLOWANCE FOR FLOTATION COSTS. PLEASE COMMENT ON FLOTATION COSTS.

A. 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 represents monetary compensation to the security underwriter for marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (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."

Flotation costs for common stock are analogous to the flotation costs associated with past bond issues which, as a matter of routine regulatory policy, continue to be amortized over the life of the bond, even though no new bond issues are contemplated. In the case of common stock, which 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.

As demonstrated in my direct testimony, the expected dividend yield component of the DCF model must be adjusted for flotation cost by dividing it by (1 - f), where f is the flotation cost factor.

Q. WHAT FLOTATION COST TREATMENT DID MR. BAUDINO RECOMMEND IN THIS CASE?

A. Mr. Baudino's common equity return recommendation does not include any allowance for issuance expense (Page 23 lines 17-19). Because Mr. Baudino fails to include any allowance for flotation costs, his DCF estimates of equity costs are understated by 20 basis points, as shown in Appendix A of my direct testimony.

I am surprised by Mr. Baudino's reluctance to accept flotation costs. Obviously, common equity capital is not free. The flotation cost allowance to the cost of common equity capital is routinely discussed and applied in most corporate finance textbooks.

Mr. Baudino's disregard of flotation costs is inconsistent with Value Line data on historical and projected common stock issues. Electric utilities have, and will continue to be issuing new common stock in the future.

Q. HOW DOES MR. BAUDINO JUSTIFY HIS DISMISSAL OF FLOTATION COST?

A. On page 34 lines 11-13 and lines 18-19 of his testimony, Mr. Baudino argues that flotation costs are already accounted for in current stock prices and that adding such an adjustment would constitute double counting. In other words, current stock prices "*most likely*" already account for such costs, he claims, although he is not quite sure and does not substantiate this claim.

I disagree with this argument. Whatever the stock price is does not change the fact that a portion of the capital contributed by equity investors is not available to earn a return because it is paid out as flotation costs. The simple fact of the matter is that in issuing common stock, the company's common equity account is credited by an amount less than the market value of the issue, so that the company must earn slightly more on its reduced equity base in order to produce a return equal to that required by shareholders. The costs are there irrespective of the stock price.

F. DCF Growth Rates

Q. WHAT GROWTH RATE PROXIES DID MR. BAUDINO EMPLOY IN HIS DCF ANALYSIS?

A. Mr. Baudino calculates four different growth proxies in his DCF analysis shown on Exhibit RAB-4 page 1 of 2:

1. Value Line Dividend Growth Forecast
2. Value Line Earnings Growth Forecast
3. Analyst Growth Forecasts in Zacks
4. Analyst Growth Forecasts in Yahoo Finance

Q. DO YOU AGREE WITH MR. BAUDINO'S GROWTH PROXIES?

A. I agree with three of Mr. Baudino's forecasts: Value Line Earnings Growth, Zacks analysts' forecasts, and Yahoo Finance analysts' forecasts. I disagree with Value Line's dividend growth forecast.

Q. SHOULD THE VALUE LINE DIVIDEND GROWTH FORECASTS BE CONSIDERED IN APPLYING THE DCF MODEL TO ELECTRIC UTILITIES?

A. No, they should not. I disagree with the use of dividend growth forecasts. Reliance on "near-term" dividend growth is improper because in the current environment where utilities are increasing their capital expenditures, dividends cannot be expected to grow at the same rate that investors expect earnings to grow. Mr. Baudino's own data on Exhibit RAB-4 shows a Value Line projected dividend growth rate that is less than the Value Line earnings growth rate. This is not surprising because it is likely that energy utilities will likely lower their dividend payout ratio over the next several years in response to very high external capital needs and rising business risks.

In short, dividend growth rates are unlikely to provide a meaningful guide to investors' growth expectations for energy utilities. Therefore, earnings growth provides a more meaningful guide to investors' long-term growth expectations. After all, it is growth in earnings that will support future dividends and share prices.

Q. WHAT GROWTH RATES SHOULD MR. BAUDINO HAVE USED?

A. For reasons outlined above, Mr. Baudino should have relied on three of his four growth proxies: Value Line earnings growth, Zacks analyst growth forecasts, and Yahoo Finance analyst forecasts, and rejected dividend growth.

Q. DR. MORIN, PLEASE PROVIDE A SUMMARY OF THE RECOMMENDED CHANGES TO MR. BAUDINO'S DCF ANALYSIS.

A. Attachment RAM-Rebuttal-1, Page 1 replicates the upper panel of Mr. Baudino's original growth rates shown on his Exhibit RAB-4. Attachment RAM-Rebuttal-1, Page 2 shows the same table without the Value Line dividend growth forecasts for reasons discussed above. Attachment RAM-Rebuttal-2 replicates Mr. Baudino's Exhibit RAB-4 Page 2, but without the dividend growth proxy. Also, the expected dividend yield is calculated correctly my multiplying the dividend yield by (1 + g) rather than by (1 + 0.5g). Also, 20 basis points were added to the expected dividend yield in order to account for flotation costs. The final amended DCF results range from 8.27% to 9.74% with an average of 8.82% using Method 1, and range from 8.02% to 9.50% with an average of 8.76% using Method 2.

The average result of 8.82% from method 1 exceeds Mr. Baudino's estimate of 8.53% by 29 basis points, and the average result of 8.76% from method 2 exceeds his estimate of 8.48% by about the same amount at 28 basis points.

G. CAPM Risk-Free Rate

Q. DOES MR. BAUDINO PERFORM A CAPM ANALYSIS?

A. Yes, he does, although he does not rely on its results in his final recommendation. The results of his CAPM study are summarized on page 29 lines 9-12 of his testimony and detailed on Exhibit RAB-5.

Q. WHAT INPUT DATA DOES A CAPM ANALYSIS REQUIRE?

A. To implement the CAPM, three quantities are required: the risk-free rate (R_F), beta (β), and the MRP (MRP). As shown on Exhibit RAB-5, Mr. Baudino uses a risk-free rate in a range of 2.32% - 3.00%, a beta of 0.60, and a MRP in a range of 8.42% - 9.10%.

H. Beta Estimate

Q. DR. MORIN, DO YOU AGREE WITH MR. BAUDINO'S BETA ESTIMATE IN THE CAPM ANALYSIS?

A. Yes, I do.

I. Risk-Free Rate Estimate

Q. DR. MORIN, DO YOU AGREE WITH MR. BAUDINO'S RISK-FREE RATE IN THE CAPM ANALYSIS?

A. No, I do not. In the same way in which Mr. Baudino relied on growth forecasts in the DCF, he should have similarly relied on interest rate forecasts in the CAPM analysis.

Mr. Baudino's risk-free rate assumption of a 2.32% - 3.00% range (midpoint 2.66%) is low for purposes of applying the CAPM. Interest rate forecasts are higher. All the economic forecasts of which I am aware call for a substantial increase in interest rates. Mr. Baudino himself cites the Federal Reserve's projections of interest rates on page 10 lines 26-29.

As shown in my prefiled direct testimony in this proceeding, each of the Congressional Budget Office, the U.S. Department of Labor, the U.S. Energy Information Administration, Global Insight, and Value Line projects higher long-term Treasury interest rates, with an average of 4.2 %.

Mr. Baudino should have relied on projected long-term Treasury interest rates for the simple reason that investors price securities on the basis of long-term expectations, including interest rates. Cost of capital estimates, including CAPM estimates, are prospective (*i.e.* forward-looking) in nature and must take into account current market expectations for the future. Mr. Baudino understates his CAPM projections by using a risk-free rate that is 154 basis points (4.20% - 2.66% = 1.54%) lower than projected.

Q. WHY SHOULD MR. BAUDINO'S ANALYSIS HAVE RELIED ON PROSPECTIVE RISK-FREE RATES IN THE CAPM ANALYSIS?

A. Mr. Baudino uses current interest rates in his CAPM analysis instead of forecast interest rates, and objects to my use of forecast interest rates. But given that this proceeding is to provide ROE estimates for future proceedings, forecast interest rates are far more relevant. I note that Mr. Baudino generously uses projections of other financial variables in all his analyses. In particular, he relies extensively on earnings and dividend growth projections in his DCF analyses and uses Value Line projections in deriving the MRP in his CAPM analysis. So, it is a mystery as to why he uses projections for most of his financial variables, but not for interest rates.

Mr. Baudino should have relied on projected long-term Treasury interest rates for the simple reason that investors price securities on the basis of long-term expectations, including interest rates. Cost of capital models, including CAPM estimates, are prospective (*i.e.* forward-looking) in nature and must take into account current market expectations for the future because investors price securities on the basis of long-term expectations, including interest rates. As he himself states on page 19 lines 2-3:

"Finally, the relevant time frame is prospective rather than retrospective."

Again on page 20 line 20, he states:

"Return on equity analysis is a forward-looking process."

In the same way that Mr. Baudino relies on forecast growth rates in his DCF analyses, he should have relied on interest rate forecasts are proxies for the risk-free rate in the CAPM analysis.

Q. IS MR. BAUDINO CORRECT THAT LITTLE WEIGHT SHOULD BE PLACED ON INTEREST RATE FORECASTS IN PROJECTING THE RISK-FREE RATE FOR CAPM ANALYSES?

A. No, he is not. On pages 38 lines 17-18 Mr. Baudino erroneously suggests that investors and regulatory bodies should place little weight on interest rate forecasts because they are often wrong, including the forecasts I used in my own CAPM analysis, and therefore should not be used as proxies for the risk-free rate in implementing the CAPM. One wonders if Mr. Baudino feels the same way about analyst growth forecasts on which he relies upon in his DCF analysis which often turn out to be wrong.

I disagree with Mr. Baudino's point of view on economic forecasts. Investors' required returns can and do shift over time with changes in capital market conditions, hence the importance of considering interest rate forecasts. The fact that organizations such as Value Line, IHS (Global Insight), EIA, and Blue Chip among many others devote considerable expertise and resources to developing an informed view of the future, and the fact that investors are willing to purchase such expensive services confirms the importance of economic/financial forecasts in the minds of investors. The issue is not whether interest rate forecasts are accurate but whether or not they are incorporated in stock prices and investor expectations. The empirical evidence demonstrates that stock prices do indeed reflect prospective financial input data.

J. CAPM Market Risk Premium (MRP)

Q. HOW DOES MR. BAUDINO ESTIMATE THE MRP COMPONENT OF THE CAPM?

A. Mr. Baudino relies on four MRP estimates:

- 9.10% based on Value Line market return projections using current bond yields,
- 8.42% based on Value Line market return projections using a normalized risk-free rate,
- 6.90% based on historical risk premium data, and
- 6.14% based on an old study by Ibbotson & Chen.

The average of the four MRPs is 7.64%.

Q. DR. MORIN, DO YOU AGREE WITH MR. BAUDINO'S FIRST TWO MRP ESTIMATES BASED ON VALUE LINE'S PROJECTED MARKET RETURNS?

A. No, I do not. As shown at the lower left-hand side of Exhibit RAB-5, Mr. Baudino calculates the overall market return using the DCF model, that is, he adds the dividend yield to the projected earnings growth using all the companies in the Value Line universe. He does the same thing using projected book value growth. The average of the two results produces a market return of 10.63%. He also looks at Value Line's projected overall market return of 12.21%. Averaging the two estimates of 10.63% and 12.21%, his estimate of the market return becomes 11.42%.

The problem with these MRP estimates is that Mr. Baudino relies on projected book value growth in arriving at his 10.63% estimate of market return. It is not clear as to why Mr. Baudino suddenly introduces book value growth in this particular DCF analysis of the market return when he failed to do so in all his DCF calculations for individual utilities. In any event, book value growth has little correlation with either earnings or dividend growth and should be ignored. Only earnings growth mattes in a DCF analysis, as discussed earlier.

If we remove the book value growth estimate of 8.00% from the calculations at the bottom of Exhibit RAB-5, the correct market return becomes 12.08%. Averaging the latter with the Value Line projected return of 12.21%, Mr. Baudino's market return estimate becomes 12.14% instead of his 11.42% estimate.

The two MRP estimates shown on page 1 on Exhibit RAB-5 based on a market return of 12.14% instead of 11.42% then become 9.82% and 9.14%.

Q. DR. MORIN, PLEASE COMMENT ON MR. BAUDINO'S THIRD MRP ESTIMATE?

A. For his third MRP estimate of 6.9%, Mr. Baudino relies on a long-term historical MRP of 6.9 % tabulated by Duff & Phelps for the 1926-2018 period based on arithmetic averages, as shown in the first column of numbers on Exhibit RAB-6.

Q. DR. MORIN, DO YOU AGREE WITH THIS THIRD MRP ESTIMATE?

A. Yes, I do.

Q. DR. MORIN, PLEASE COMMENT ON MR. BAUDINO'S FOURTH MRP ESTIMATE.

A. For his fourth 6.14% estimate, Mr. Baudino refers to an old 2003 study of the MRP by Ibbotson & Chen[1] which estimates a MRP of 6.14%. I find this reference highly selective and stale. There is a gigantic literature published regarding the MRP, a veritable cottage industry regarding its magnitude. Instead of selecting one of a myriad study on the MRP Mr. Baudino should have familiarize himself with the prevalent academic consensus on the magnitude of the MRP. In their widely-used authoritative textbook, following a comprehensive review of the rich and fertile MRP literature, Richard Brealey, Stewart Myers, and Franklin Allen state as follows:

[1] Ibbotson, R. G. & Chen, P. 2003 "Long-Run Stock Returns: Participating in the Real Economy, *Financial Analysts Journal*, Vol. 59, No. 1, P .88

> *Brealey, Myers, and Allen have no official position on the issue, but we believe that a range of 5 to 8 percent is reasonable for the risk premium in the United States.*[2]

My own survey of the market risk premium literature is also quite consistent with this range.[3] Mr. Baudino should have ignored this antiquated study in favor a more complete and up to date set of academic studies.

Q. WHAT MRP ESTIMATE SHOULD MR. BAUDINO HAVE USED IN HIS CAPM ANALYSIS?

A. Instead of his average MRP estimate of 7.64%, Mr. Baudino should have relied on an amended average of 8.00%[4].

Q. DR. MORIN, PLEASE PROVIDE A CORRECTED RENDITION OF MR. BAUDINO'S CAPM ESTIMATES.

A. To implement the CAPM, three quantities are required: the risk-free rate (R_F), beta (β), and the MRP (MRP). For reasons discussed earlier, Mr. Baudino should have used a risk-free rate of 4.2%, a beta of 0.60, and a MRP which averages 8.62%. The end result is A CAPM estimate of 9.4% which becomes 9.6% with a flotation costs adjustment of 20 basis points.[5] Coincidentally, this is the average allowed ROE for electric utilities of average risk discussed earlier.

[2] Richard A. Brealey, *et al.*, *Principles of Corporate Finance*, at page 180 (11th ed. 2014).
[3] *See* Roger A. Morin, *The New Regulatory Finance*, at chapter 5 (2006).
[4] Removing the stale estimate of 6.14%, the correct average MRP is, (9.82% + 9.14% + 6.90%)/3 = 8.62%
[5] ROE = 4.2% + 0.60 x 8.62% = 9.4% plus 20 basis point flotation cost adjustment

K. CAPM Versus Empirical CAPM

Q. DO YOU AGREE WITH MR. BAUDINO'S EXCLUSIVE USE OF PLAIN VANILLA VERSION OF THE CAPM TO ESTIMATE RETURNS ON EQUITY?

A. No. The plain vanilla version of the CAPM should be supplemented by the more refined version of the CAPM in estimating returns on equity. 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. 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, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, a CAPM-based estimate of the cost of capital underestimates the return required from low-beta securities and overstates the return from high-beta securities, based on the empirical evidence.

The empirical form of the CAPM that I used in my direct testimony refines the standard form of the CAPM to account for this phenomenon. As discussed in Appendix B of my prefiled direct testimony, my own empirical investigation of the relationship between return and Value Line adjusted betas is quite consistent with the general findings of the literature.

The downward-bias inherent in the CAPM is particularly significant for low-beta securities, such as the three groups of utilities used by Mr. Baudino. Mr.

Baudino's CAPM estimates of equity costs are understated by about 50 basis points (*i.e.*, 0.5 %) from this bias alone. His revised CAPM estimate of 9.40% shown above becomes 9.93% using the ECAPM adjustment even without a flotation cost adjustment.

L. Empirical CAPM

Q. DO YOU HAVE ANY COMMENTS REGARDING MR. BAUDINO'S CONCERNS WITH YOUR EMPIRICAL CAPM ANALYSIS?

A. Yes. Mr. Baudino's purported concerns with my empirical CAPM analysis on Page 39 arise from his confusing the adjustment of beta with the empirical CAPM. As discussed in Appendix B of my direct testimony, there is considerable academic and regulatory support for the use of the empirical CAPM. As explained in my direct testimony and supporting exhibit, it is essential to take into account the reality that the empirical Security Market Line described by the traditional CAPM is not as steeply sloped as the predicted Security Market Line. The empirical CAPM is thus a return adjustment which accounts for this reality and is not an adjustment to beta which is an x-axis adjustment accounting for regression bias. Hence, the use of adjusted betas is not equivalent to the empirical CAPM.

Mr. Baudino objects to the use of the ECAPM on the grounds that it suggests that Value Line betas are incorrect and that investors should not rely on them. This argument is totally specious, because the use of an adjusted beta by Value Line is correcting for a different problem than the ECAPM. The adjusted beta captures the fact that betas regress toward one over time. Value Line betas remain accurate and useful and should be relied upon. The ECAPM corrects for the fact that the CAPM under-predicts observed returns when beta is less than one and over-predicts observed returns when beta is greater than one. Mr. Baudino's criticisms are unfounded.

In other words, the CAPM under-predicts actual returns for betas less than one which is a static relationship that exists at any point in time. Therefore, one adjustment captures a dynamic process, the other captures a static one. The two adjustments are not the same and there is no double- counting. In short, the ECAPM is a return adjustment and not a beta adjustment. As I stated in my treatise on regulatory finance[6]:

> *"Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. ... This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. ... The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing".*

Q. DO YOU AGREE WITH MR. BAUDINO'S ASSESSMENT OF THE CAPM GENERIC METHODOLOGY?

A. No, I do not. On page 25 lines 1-2 and 11-12 of his testimony, Mr. Baudino argues that a considerable amount of judgment must be employed in defining the inputs to the CAPM. My immediate reaction is that the same comments apply at least as forcefully to the DCF model. I certainly agree with Mr. Baudino that judgment must be employed in defining the inputs to the CAPM, but the same is true about the

[6] Roger A. Morin, *New Regulatory Finance*, (Arlington, Virginia: Public Utilities Reports, Inc., 2006), p. 191.

DCF model. In my view, an inordinate amount of judgment is required to estimate the inputs to the DCF model, particularly the elusive growth component. There are additional judgmental elements, for example, the appropriate stock price, proxies for expected growth, sample size, risk comparability of the sample, and so on. All financial models require the use of judgment in defining the inputs data to these models, and the CAPM is no exception.

M. <u>Historical Risk Premium</u>

Q. HOW DO YOU RESPOND TO MR. BAUDINO'S COMMENT ON YOUR HISTORICAL RISK PREMIUM ANALYSIS?

A. On page 40 lines 6-8 and lines 14-16, Mr. Baudino criticizes my historical risk premium analysis on the grounds that 1) it relies on forecast interest rates instead of current interest rates, and 2) it is imprecise and constitutes a "blunt instrument". I have already discussed the impropriety of using current interest rates and the need to rely on prospective financial data[7].

As for his second argument concerning the lack of precision of this methodology no empirical evidence is offered for this unsubstantiated statement. In my view, the method is no less precise than the DCF methodology. The risk premium methodology is well-established among finance practitioners, and I am surprised Mr. Baudino did not rely on this well-known method.

The Risk Premium approach is conceptually sound and firmly rooted in the conceptual framework of Capital Market Theory. It is widely used by analysts, investors, and expert witnesses. Most college-level corporate finance and/or

[7] The same response applies to Mr. Baudino's criticism of my Allowed Risk Premium method on p. 41 lines 5-7.

investment management texts contain detailed conceptual and empirical discussion of the risk premium approach. 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.

Data requirements to implement the method are not prohibitive. The methodology is responsive to changes in capital market conditions and provides a timely signaling device for current interest rate trends in contrast to the DCF method, which may be sluggish in detecting changes in return requirements, especially when based on historical data. One advantage of risk premium over DCF is that the former takes a broader time-series perspective rather than a snapshot point-in-time viewpoint, and is therefore less vulnerable to the vagaries of any one particular capital market environment.

Mr. Baudino also argues on page 40 lines 6-9 that risk premiums can change over time and are therefore unstable over time. No empirical evidence is offered to buttress this statement. To the extent that the estimated historical equity risk premium follows what is known in statistics as a random walk, one should expect the equity risk premium to remain at its historical mean. Thus, the best estimate of the future risk premium is the historical mean. As explained in my direct testimony, at least for the market risk premium, there is no evidence that the market risk premium in common stocks has changed over time (*i.e.*, no significant serial correlation in the Duff & Phelps historical return data). Therefore, it is reasonable to assume that these quantities will remain stable in the future. In short, Mr. Baudino's remarks on my risk premium analyses are unwarranted.

N. Risk Adjustment

a). Summary

Q. DID MR. BAUDINO ALLOW FOR THE COMPANY'S RISK RELATIVE TO ITS PEERS?

A. No, Mr. Baudino did not adjust his recommended ROE upward to reflect Duke Energy Kentucky's greater than average risk on account of its significant capital expenditure program relative to its size and ancillary regulatory risks, its relatively small size, and its highly concentrated generation portfolio. In my direct testimony, I described my recommended ROE as barebones in view of the aforementioned risks. Mr. Baudino should have at least recommended the upper portion of his DCF results to account for the higher relative risks of Duke Energy Kentucky.

Q. HOW DOES MR. BAUDINO JUSTIFY HIS FAILURE TO ADJUST FOR DUKE ENERGY KENTUCKY'S HIGHER RELATIVE RISKS?

A. On page 42 lines 24-25 and on page 43 lines 11-12, Mr. Baudino argues that Duke Energy Kentucky's credit ratings are consistent with current industry credit ratings and, therefore, nothing in these credit ratings support a risk increment.

This view is inappropriate. This proceeding is mainly concerned with common stock risk/returns, and not bond risk/returns. Bondholders are concerned with creditworthiness, and bond ratings constitute a measure of creditworthiness. Common shareholders, on the other hand, are concerned with variability of returns, typically measured by beta risk measures. It is incorrect to measure a common stock's riskiness on the basis of its bond rating alone. In short, Mr. Baudino has confounded the risk of bonds and the risk of common stocks. The same applies to

Mr. Baudino's view on Duke Energy Kentucky's asset concentration being already reflected in credit ratings.

b). Size Effect

Q. IS MR. BAUDINO CORRECT IN ASSERTING THAT IT IS INAPPROPRIATE TO TAKE INTO ACCOUNT SIZE DIFFERENCES OF COMPANIES WHEN DETERMINING THE RETURN ON EQUITY?

A. No. On page 43 lines 5-6, Mr. Baudino rejects the notion that Duke Energy Kentucky's very small size warrants an upward ROE adjustment because there is no evidence to suggest that a size premium applied to small companies. His argument is that the size effect which is well documented in the Duff & Phelps Valuation book cited by Mr. Baudino is simply the result of the fact that small companies have a higher beta and therefore higher returns. This is simply incorrect. I quote directly from the Duff & Phelps Valuation Yearbook cited by Mr. Baudino:

"The capital asset pricing model, or CAPM, does not fully account for the higher returns of small-cap stocks." (Page 7-16)

"Smaller deciles have had returns that are not fully explained by their higher betas. This size-related phenomenon prompted a revision to the CAPM to include a size premium". (Page 7-16)

I believe Mr. Baudino misunderstands the vast literature on the subject. The greater risk of small stocks does not fully account for their higher returns over many historical periods. The average small stock premium is well in excess of that of the average stock, **more than could be expected by risk (beta) differences alone**, suggesting that the cost of equity for small stocks is considerably larger than for large capitalization stocks.

I was surprised by Mr. Baudino's position on the size effect because the size phenomenon effect is well-known and well documented in the financial literature. Investment risk increases as company size diminishes, all else remaining constant. Small companies have very different returns than large ones and on average those returns have been higher. Small companies earn many different returns than large ones, and on average the actual returns of small companies have been higher, as is well documented in the financial literature. Indeed, the Duff & Phelps Valuation book cited by Mr. Baudino his testimony devotes a full chapter documenting and quantifying the size effect.

c). Reliance on DCF

Q. SHOULD THE COMMISSION RELY EXCLUSIVELY ON THE DCF AS MR. BAUDINO DOES?

A. No, it should not. No one single method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data. 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. Hence, several methodologies applied to several comparable risk companies should be employed to estimate the cost of common equity.

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

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

In short, the Commission should consider all the relevant evidence presented.

III. CONCLUSIONS REGARDING MR. BAUDINO'S RECOMMENDATIONS

Q. WHAT DO YOU CONCLUDE FROM MR. BAUDINO'S TESTIMONY?

A. I agree with several of Mr. Baudino's views and procedures: (i) his sample of utility companies in his DCF and CAPM analyses; (ii) his use of analysts' growth forecasts as proxies for expected growth in the classic DCF model; (iii) his beta estimates in the CAPM analysis, (iv) a portion of his MRP estimates in the CAPM analysis, and (v) his capital structure recommendation.

However, there are weaknesses in Mr. Baudino's methodologies. His ROE recommendation, which would represent among the lowest allowed ROE in the country, should be rejected by the Commission.

As I demonstrated earlier, Mr. Baudino has understated his DCF results by a minimum of 62 basis points: 12 basis points from miscalculating the dividend yield component of the DCF model, 30 basis point from adjusting for the proper growth rates in the DCF model, and 20 basis points from omitting flotation costs. That alone would increase his 9.00% ROE recommendation to 9.62% even without the upward risk adjustment. Mr. Baudino has also understated his CAPM results, but in fairness to Mr. Baudino he accords little weight, if any, to the results from this particular methodology.

Q. WOULD THE ADOPTION OF MR. BAUDINO'S UNDERSTATED RECOMMENDED ROE ENDANGER DUKE ENERGY KENTUCKY'S CREDIT QUALITY?

A. Yes, it certainly increases the probability of a deterioration in Duke Energy Kentucky's creditworthiness. Decreases in Duke Energy Kentucky's authorized ROE, such as the decrease recommended by Mr. Baudino, could very well threaten Duke Energy Kentucky's creditworthiness. A weakening of Duke Energy Kentucky's financial viability and earnings power at a time when Duke Energy Kentucky needs to attract significant external capital on reasonable terms is ill-advised.

Q. HAS MR. BAUDINO PRESENTED ANY ARGUMENTS THAT WOULD CAUSE YOU TO ALTER YOUR RECOMMENDATIONS?

A. No, he has not.

IV. UPDATED ANALYSIS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR REBUTTAL TESTIMONY?

A. The purpose of this section of my rebuttal is to update my ROE recommendation in view of the appreciable changes that have occurred in capital market conditions since I prepared my direct testimony in mid-2019.

Q. CAN YOU BRIEFLY DESCRIBE THE BEHAVIOR OF STOCK PRICES AND INTEREST RATES SINCE YOU PREPARED YOUR REBUTTAL TESTIMONY?

A. In short, stock prices have increased and forecast interest rates have decreased. As seen from the summary table below and shown in detail in Updated Attachment RAM-Rebuttal-4 and Attachment RAM-Rebuttal-5, the DCF results for the electric utilities have decreased in response to higher stock prices (lower dividend yields) and lower expected growth rates.

The level of U.S. Treasury 30-year long-term bond yield forecast is 3.9%, versus 4.2% when I prepared my direct testimony. This slight decrease in forecast interest rates lowers the CAPM, ECAPM, Historical Risk Premium, and Allowed Risk Premium results in my direct testimony by 30 basis points.

Q. DR. MORIN, WHAT HAS HAPPENED TO ELECTRIC UTILITY BETAS SINCE YOU PREPARED YOUR DIRECT TESTIMONY?

A. They have decreased very slightly from 0.60 to 0.59, thus slightly lowering the CAPM and ECAPM results.

Q. DR. MORIN, HAS THE MARKET RISK PREMIUM (MRP) CHANGED SINCE YOU PREPARED YOUR DIRECT TESTIMONY?

A. Yes, it has increased slightly from 7.4% to 7.8% in response to the lower level of forecast interest rates. This partially offsets the decrease in interest rates in the CAPM and ECAPM analyses.

Q. DR. MORIN, PLEASE SUMMARIZE YOUR UPDATED RESULTS FROM THE VARIOUS METHODOLOGIES.

A. The net result of these capital market changes is a net decrease in the cost of common equity. Alongside the original results, the updated cost of common equity estimates as of December 2019 are summarized in the table below.

METHODOLOGY	**ROE RESULTS**	
	Original	**Updated**
CAPM	9.0%	8.7%
Empirical CAPM	9.7%	9.7%
Historical Risk Premium Elec Utility Industry	10.5%	10.2%
Allowed Risk Premium	10.4%	10.2%
DCF Elec Utilities Value Line Growth	10.0%	9.5%
DCF Elec Utilities Analyst Growth	8.9%	8.4%

The updated average result from all the tests is 9.5% and the median is 9.6%. If we remove the outlying result of 8.4%, the average result is 9.7%.

V. <u>CONCLUSION</u>

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

A. Based on current capital market conditions and the application of my professional judgment, it is my opinion that a just and reasonable return on the common equity capital of Duke Energy Kentucky's electric utility operations in the State of Kentucky is a minimum of 9.7%. Given the higher relative risks of Duke Energy Kentucky discussed in my direct testimony, including the Company's small size, generation concentration, and the magnitude of its construction program, it would not be unreasonable to allow a return in the upper range of my updated results. I would note that the 9.8% ROE that I recommended in my Direct Testimony remains within the range, albeit the upper end range, of my updated results.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

PROXY GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(4) Zacks	(5) Yahoo! Finance
Alliant Energy	5.50%	6.50%	5.49%	5.00%
Ameren Corp.	6.00%	6.50%	6.16%	4.70%
Avista	4.00%	3.50%	3.32%	3.40%
Black Hills	6.50%	5.00%	4.27%	3.66%
CenterPoint Energy	2.50%	12.50%	4.76%	4.10%
Chesapeake Utilities	9.00%	9.00%	7.00%	6.00%
CMS Energy Corp.	7.00%	7.00%	6.42%	7.50%
Consolidated Edison	3.50%	3.00%	2.00%	2.78%
Dominion Energy	5.00%	6.50%	4.81%	4.46%
DTE Energy Co.	6.00%	5.50%	6.00%	4.83%
Duke Energy Corp.	2.50%	6.00%	4.84%	4.65%
Eversource Energy	5.50%	5.50%	5.63%	5.60%
Exelon Corp.	5.50%	9.00%	4.50%	N/A
Fortis	6.00%	4.00%	5.68%	N/A
MGE Energy	5.00%	6.00%	N/A	4.00%
NorthWestern Corp.	4.50%	3.00%	2.73%	3.20%
Pub Sv Enterprise Grp.	5.00%	6.00%	3.69%	3.70%
Sempra Energy	8.00%	11.00%	7.73%	9.75%
WEC Energy Group	6.00%	6.00%	6.14%	6.15%
Xcel Energy Inc.	6.00%	5.50%	5.42%	5.20%
Averages	**5.45%**	**6.35%**	**5.08%**	**4.93%**
Median Values	**5.50%**	**6.00%**	**5.42%**	**4.68%**

Sources: Exhibit RAB-5

PROXY GROUP
CORRECTED DCF RETURN ON EQUITY

	(1) Value Line Earnings Gth.	(2) Zack's Earnings Gth.	(3) Yahoo! Earnings Gth.	(4) Averages
Method 1:				
Dividend Yield	3.00%	3.00%	3.00%	3.00%
Average Growth Rate	6.35%	5.08%	4.93%	5.45%
Expected Div. Yield	3.39%	3.35%	3.35%	3.36%
DCF Return on Equity	***9.74%***	***8.44%***	***8.27%***	**8.82%**
Method 2:				
Dividend Yield	3.11%	3.00%	3.00%	3.04%
Median Growth Rate	6.00%	5.42%	4.68%	5.37%
Expected Div. Yield	3.50%	3.36%	3.34%	3.40%
DCF Return on Equity	***9.50%***	***8.78%***	***8.02%***	**8.76%**

Natural Gas Distribution Utilities
DCF Analysis Value Line Growth Rates

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Projected EPS Growth	(4) % Expected Divid Yield	(5) Cost of Equity	(6) ROE
1	Atmos	2.00	7.50	2.15	9.65	9.76
2	Chesapeake Util	1.81	8.50	1.96	10.46	10.57
3	NJ Res	2.51	9.50	2.75	12.25	12.39
4	NISource	3.07	5.50	3.24	8.74	8.91
5	Northwest Nat Gas	2.67	4.30	2.78	7.08	7.23
6	ONE Gas	2.21	10.50	2.44	12.94	13.07
7	So Jersey Ind	3.18	9.50	3.48	12.98	13.17
8	Southwest Gas	2.58	9.00	2.81	11.81	11.96
9	Spire	2.99	7.50	3.21	10.71	10.88
10	UGI	1.86	8.00	2.01	10.01	10.11
12	**AVERAGE**	**2.49**	**7.98**	**2.68**	**10.66**	**10.81**

Notes:

15 Column 2: Zacks Investment Research Oct 2018

16 Column 3: Value Line Investment Reports Oct 2018

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

18 Column 5 = Column 4 + Column 3

19 Column 6 = Column 4/0.95 + Column 3

Natural Gas Distribution Utilities
DCF Analysis Analysts' Growth Rates

	(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Company Name	Current Dividend Yield	Projected EPS Growth	% Expected Divid Yield	Cost of Equity	ROE
1	Atmos	2.00	6.50	2.13	8.63	8.74
2	Chesapeake Util	1.81	6.00	1.92	7.92	8.02
3	NJ Res	2.51	7.00	2.69	9.69	9.83
4	NISource	3.07	5.50	3.24	8.74	8.91
5	Northwest Nat Gas	2.67	4.30	2.78	7.08	7.23
6	ONE Gas	2.21	5.70	2.34	8.04	8.16
7	So Jersey Ind	3.18	12.20	3.57	15.77	15.96
8	Southwest Gas	2.58	4.00	2.68	6.68	6.82
9	Spire	2.99	4.00	3.11	7.11	7.27
10	UGI	1.86	8.00	2.01	10.01	10.11
12	**AVERAGE**	**2.49**	**6.32**	**2.65**	**8.97**	**9.11**

Notes:

15 Column 2, 3: Zacks Investment Research Oct 2018

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

18 Column 5 = Column 4 + Column 3

19 Column 6 = Column 4/0.95 + Column 3

VERIFICATION

STATE OF FLORIDA	**)**	
	)	**SS:**
COUNTY OF NASSAU	**)**	

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

Roger A. Morin

Dr. Roger A. Morin Affiant

Subscribed and sworn to before me by Dr. Roger A. Morin on this 13 day of January, 2020.

NOTARY PUBLIC

My Commission Expires:

CRISTINA HAWBAKER
MY COMMISSION # FF998315
EXPIRES June 02, 2020
(407) 398-0153 FloridaNotaryService.com

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2019-00271

REBUTTAL TESTIMONY OF

LESLEY G. QUICK

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

January 31, 2020

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lesley G. Quick and my business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Carolinas, LLC (DEC) as Vice President Revenue Services. DEC is a subsidiary of Duke Energy Corporation (Duke Energy) which provides various services to Duke Energy Kentucky, Inc. (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy. **Q. ARE YOU THE SAME LESLEY G. QUICK THAT PROVIDED DIRECT TESTIMONY IN THIS PROCEEDING?**

A. Yes.

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

A. The purpose of my rebuttal testimony is to respond to the Attorney General's witness Lane Kollen's recommendation regarding the Company's proposal to eliminate the per transaction fees that customers currently experience when they wish to pay their bill by credit card, debit card, or electronic check and to instead include those costs in base rates.

II. DISCUSSION

Q. PLEASE SUMMARIZE WHAT THE COMPANY IS PROPOSING WITH RESPECT TO ITS FEE-FREE PAYMENT PROPOSAL IN THIS CASE.

A. Today, residential customers who pay their utility bill using a credit card, debit card or electronic check through any authorized Duke Energy payment channel (IVR, web, Mobile App, or over the phone via live customer service representative) are charged a $1.50 convenience fee per transaction. The convenience fee is collected from the customer by the Company's third-party vendor, SpeedPay, and is applicable to all channels listed above including live customer service. The Company receives no portion of this fee. Duke Energy Kentucky is proposing to eliminate the per transaction fee that SpeedPay currently charges residential customers, and instead, SpeedPay would charge Duke Energy Kentucky and in turn the Company would include these costs as a cost of service in the overall revenue requirement.

Q. PLEASE DESCRIBE MR. KOLLEN'S RECOMMENDATION REGARDING THE COMPANY'S FEE-FREE CREDIT CARD TRANSACTION PROPOSAL.

A. Mr. Kollen's discussion of this issue begins on page 27 of his Direct Testimony. While Mr. Kollen is not opposed to eliminating the transaction fee itself, he recommends the Commission deny the Company's request to include the transaction fees for customers using credit cards, debit cards or electronic checks as an expense in the revenue requirement. He recommends a reduction in the Company's proposed revenue requirement of $0.494 million to remove these costs.

Q. DOES DUKE ENERGY KENTUCKY AGREE WITH MR. KOLLEN'S RECOMMENDATION?

A. No.

Q. PLEASE EXPLAIN.

A. As I mentioned in my direct testimony, the requirement to pay a convenience fee when making a payment is one of the largest frustrations that customers experience. Customers have grown accustomed to products and services that allow for the use of credit or debit card without a separate, additional fee. The Company is proposing the fee-free program to increase customer satisfaction by offering payment options that are more in line with the expectations in today's digital age. Bearing in mind that the electronic payment option is available to all residential customers, the cost of this fee free program is like all other billing and payment programs offered by the Company and should be recovered as a cost of serving customers.

Q. DO YOU AGREE WITH MR. KOLLEN'S CLAIM THAT THERE WILL BE OFFSETTING SAVINGS FROM REDUCTIONS OF OTHER EXPENSES THAT WILL RESULT FROM INCREASED CUSTOMER PARTICIPATION?

A. Yes, but the savings are not known and measurable at this time.

Q. WHY SHOULD THE COMMISSION APPROVE THE COMPANY'S FEE-FREE TRANSACTION PROPOSAL?

A. The Commission should approve the Company's fee-free program to meet changing customer expectations. Customers are becoming increasingly accustomed to the convenience of using credit cards, debit cards, and electronic forms of payment without paying a separate transaction fee. We are currently seeing a 13% average year-over-year growth in credit/debit card transactions. Giving customers options to pay by the method of their choice without incurring additional fees will lead to more satisfied customers.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE FEE-FREE TRANSACTION PROPOSAL?

A. The Company recommends the Commission treat these electronic payment transaction costs the same as other billing and payment costs. By including credit card, debit card and electronic check transaction costs in the cost of service, it increases customer satisfaction and reduces customer confusion. The Commission should deny Mr. Kollen's recommendation to exclude these costs from the Company's proposed revenue requirement.

III. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

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

The undersigned, Lesley G. Quick, Vice President Revenue Services, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing rebuttal testimony and that it is true and correct to the best of her knowledge, information and belief.

Lesley G. Quick

Lesley G. Quick Affiant

Subscribed and sworn to before me by Lesley G. Quick on this 13 day of January, 2020.

Lori S Thompson

NOTARY PUBLIC

My Commission Expires:

LORI S THOMPSON NOTARY PUBLIC EXP. 03/18/2022 MECKLENBURG COUNTY, NC

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2019-00271

REBUTTAL TESTIMONY OF

LANG W. REYNOLDS

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

January 31, 2020

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lang W. Reynolds and my business address is 550 South Tryon, Charlotte, North Carolina 28202.

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

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

Q. ARE YOU THE SAME LANG W. REYNOLDS THAT FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

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

A. The purpose of my rebuttal testimony is to respond to the recommendations of Brian Collins on behalf of Northern Kentucky University, as well as those of Lane Kollen on behalf of the Kentucky Attorney General. In doing so, I will explain why the Commission should approve the Company's Electric Vehicle/Transportation Pilot Program (EV Pilot), and explain the benefits provided to customers of the Company's proposal.

II. DISCUSSION

A. RESPONSE TO MR. COLLINS' RECOMMENDATIONS

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS OF MR. COLLINS ON BEHALF OF NORTHERN KENTUCKY UNIVERSITY.

A. Mr. Collins makes several recommendations that he describes as customer protections that the Commission should require if it approves the Company's EV Pilot proposal. These recommendations are summarized as follows:

1. The Commission should limit the investment and O&M costs in the EV Pilots to those total dollar values listed on Table 1 of my direct testimony and the EV Pilot investment totals should be restricted to those investment totals until a further evaluation of the program is conducted.
2. All revenues generated from all EV Pilot programs should be recorded as an offset to the deferred O&M costs (regulatory asset) proposed by Duke Energy Kentucky. To the extent the revenues exceed the O&M costs, then a regulatory liability would be created to capture those revenues to be returned to customers in the next rate case.
3. No extension of the Pilot Programs recovery of investment in EV Bus Charging Stations and Fast Charging Stations should occur beyond three years without prior Commission approval. If stranded investment occurs because of changes in site ownership, any party

is free to argue whatever position they desire regarding recovery of those stranded investments.

4. The Commission should require Duke Energy Kentucky to maintain all documentation necessary to perform a cost/benefit study. The cost/benefit study should be filed at the conclusion of the EV Pilots. In addition, the Company should file the cost benefit study with the direct testimony of Duke Energy Kentucky during its next rate case if that rate case occurs before the expiration of the EV Pilots. The cost/benefit analysis should be filed in the public record in order to afford the ratepayers the opportunity to independently assess project benefits.
5. The Commission should prohibit Duke Energy Kentucky from expanding the EV Pilots before the expiration of the current program. However, if the Commission does allow Duke Energy Kentucky to seek expansion of the program before the currently proposed expiration by way of a subsequent filing, all Parties to the current rate case should be notified by Duke Energy Kentucky and be afforded the opportunity to participate in the filing or proceeding.
6. Once the Pilot program has expired, the Commission should consider whether a separate Electric Vehicle (EV) class should be created to ensure that EV customers pay actual, non-subsidized cost of service rates for this service and help prevent other Duke Energy Kentucky customers from subsidizing EV investment.

7. Any funds received from the Volkswagen Environmental Mitigation Trust Program should be recorded as a regulatory liability to reduce the EV investment in a future Duke Energy Kentucky rate case.

Q. DOES DUKE ENERGY KENTUCKY AGREE TO MR. COLLINS' FIRST RECOMMENDATION LIMITING THE INVESTMENT AND O&M COSTS IN THE EV PILOTS TO THOSE TOTAL DOLLAR VALUES LISTED ON TABLE 1 OF YOUR DIRECT TESTIMONY?

A. Yes. The Company would agree to limiting the EV Pilot to the investment described in Table 1 of my direct testimony.

Q. DOES DUKE ENERGY KENTUCKY AGREE TO MR. COLLINS' SECOND RECOMMENDATION THAT ALL REVENUES GENERATED FROM ALL EV PILOT PROGRAMS SHOULD BE RECORDED AS AN OFFSET TO THE DEFERRED O&M COSTS (REGULATORY ASSET) PROPOSED BY DUKE ENERGY KENTUCKY AND THAT THE EXTENT THE REVENUES EXCEED THE O&M COSTS, THEN A REGULATORY LIABILITY WOULD BE CREATED TO CAPTURE THOSE REVENUES TO BE RETURNED TO CUSTOMERS IN THE NEXT RATE CASE?

A. Yes, but only for the EV Fast Charging Program. As stated in my direct testimony, the Company has already proposed to credit customers with any net revenue received from the EV Fast Charge Fee received by the Company from the EV Fast Charging Program through Rider PSM. Alternatively, the Company is not opposed to the Commission requiring an offset to deferred O&M costs using revenues associated with the EV Fast Charge Fee. However, the Company's proposal of including net revenues in Rider PSM will return the revenues to customers immediately through a quarterly rider filing vs. waiting for a future rate case. There is no incremental revenue with the EV Pilot from the Company's other rate schedules, as those customers are simply paying the standard tariff rate and such sales are already factored into overall sales in the revenue requirement (*e.g.*, residential customers who receive the incentive for an in-home charging station will be served under rate RS).

Q. DOES DUKE ENERGY KENTUCKY AGREE TO MR. COLLINS' THIRD RECOMMENDATION THAT THERE BE NO EXTENSION OF THE PILOT PROGRAMS RECOVERY OF INVESTMENT IN EV BUS CHARGING STATIONS AND FAST CHARGING STATIONS BEYOND THREE YEARS WITHOUT PRIOR COMMISSION APPROVAL AND THAT, IF STRANDED INVESTMENT OCCURS BECAUSE OF CHANGES IN SITE OWNERSHIP, ANY PARTY IS FREE TO ARGUE WHATEVER POSITION THEY DESIRE REGARDING RECOVERY OF THOSE STRANDED INVESTMENTS?

A. No, the Company believes it is essential to the success of the EV Pilot for the Company to offer potential participating customers a clear line of sight on ownership, operation and maintenance of the EV charging infrastructure for the full useful life of the asset. Based on real-world experience in other similar programs, participating customers are very wary about contracting for a program where there is future uncertainty. A large degree of uncertainty around ownership, operation, and maintenance of the EV charging infrastructure throughout the full useful life of the assets will make the contracting process virtually impossible as participants will have no clear idea of what will happen after the EV Pilot time period has elapsed. The 3-year time limit on the Pilot was designed to provide a timeline for the creation of future cost-effective programs following the EV Pilot; so, the Company is indeed proposing that further Commission approval be required before the EV Pilot programs are scaled to permanent offerings.

Q. DOES DUKE ENERGY KENTUCKY AGREE TO MR. COLLINS' FOURTH RECOMMENDATION REGARDING THE PREPARATION AND FILING OF COST/BENEFIT ANALYSIS?

A. The Company has spelled out in detail the large amount of analysis it is committing to perform using data gathered from the EV Pilot, including the costs and benefits of charging the different types of electric vehicles served by each program within the EV Pilot. This data will be used to scale future Electric Transportation programs as justified following the EV Pilot program. The Company will prepare a final EV Pilot report and submit it to the Commission 180 days after the conclusion of the EV Pilot. The Company is also open to a collaborative process for the creation of the final report and will incorporate stakeholder input on the content of the final report.

Q. DOES DUKE ENERGY KENTUCKY AGREE TO MR. COLLINS' FIFTH RECOMMENDATION REGARDING THE EXPANSION OF THE EV PILOTS?

A. The Company proposed a 3-year duration for the EV Pilot specifically because it agrees that the EV Pilots should be concluded and analyzed before future programs are scaled. Therefore, the Company agrees with this recommendation.

Q. DOES DUKE ENERGY KENTUCKY AGREE TO MR. COLLINS' SIXTH RECOMMENDATION REGARDING THE POTENTIAL TO CREATE A SEPARATE EV CUSTOMER CLASS?

A. No, it is far too early to create a separate EV customer class. The EV Pilot is designed to gather the data necessary to evaluate many questions which may include the creation of a separate customer class. As described in Attachment LWR-1, the analysis shows that incremental EV adoption can benefit all utility customers over the long term by providing net revenue to the utility system in excess of the cost to serve EV charging load. If EV customers are separated into their own class, these benefits do not accrue to all customers but would rather be contained within the EV customer class. Moreover, there is a potential that the number of registered EVs in Duke Energy Kentucky's territory may be under 10,000 at the conclusion of the pilot. In addition to the low EV population size creating a cost-prohibitive approach to a new customer class, creating a new EV-specific rate class presents several new challenges such as establishing metering requirements and standards across all EV programs, which may not be cost-effective for our customers. The

Company will evaluate pilot learnings and determine the best path forward for creating separate EV charging rates following the conclusion of the Pilot.

Q. DOES DUKE ENERGY KENTUCKY AGREE TO MR. COLLINS' SEVENTH RECOMMENDATION REGARDING THE TREATMENT OF THE VW SETTLEMENT FUNDS?

A. Yes, the Company has already committed to reducing any recoverable amounts by any amount of funding received from the VW Settlement Environmental Mitigation Trust. In my direct testimony I mention that any VW funding received would offset the deferral requested within the EV Fast Charge program. Currently the Kentucky Energy and Environmental Cabinet has not released a final Beneficiary Mitigation Plan with information on how the Commonwealth will distribute any future funding for light duty EV charging infrastructure.

B. RESPONSE TO MR. KOLLEN'S RECOMMENDATIONS

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS OF MR. KOLLEN ON BEHALF OF THE KENTUCKY ATTORNEY GENERAL REGARDING THE EV PILOT.

A. Mr. Kollen's discussion of the Company's EV Pilot begins on page 62 of his direct testimony. Mr. Kollen believes the Company's proposal is not necessary, uneconomic, and will not benefit all customers and should be denied. The result of Mr. Kollen's recommendation is a reduction of $0.145 million from the Company's revenue requirement.

Q. PLEASE RESPOND TO MR. KOLLEN'S CRITICISMS OF THE EV PILOT NOT BEING NECESSARY FOR THE PROVISION OF ELECTRIC SERVICE.

A. Mr. Kollen argues that the EV Pilot programs are not necessary for the provision of electric service. Duke Energy Kentucky operates many programs which are not strictly necessary for the provision of electric service but do provide other economic or electric system benefits including Economic Development, Demand Side Management, and Customer Assistance Programs. Electric transportation is no different from such programs which drive electric system and economic benefits and are available to all Duke Energy Kentucky customers.

Q. PLEASE RESPOND TO MR. KOLLEN'S CRITICISMS OF THE EV PILOT BEING A DOWN PAYMENT ON ADDITIONAL INVESTMENTS.

A. Mr. Kollen goes on to argue that the Pilot programs are only a "down payment on additional investments that will be premised on the 'success' of the Pilot programs." Admittedly, the Company hopes that through a successful Pilot, it can plan to scale future EV programs in order to secure the potential future benefits of EV growth. However, at that time the Company will have the requisite data to determine the costs and benefits of EV charging and can adjust incentive levels and programmatic features to ensure future programs are cost effective and justified on their own merits. The Pilot will provide critical data for future program decisions through a controlled and measured approach with Commission oversight. Furthermore, any future programs will be subject to Commission approval at that time, so Pilot approval does not constrain the Commission's ability to evaluate, approve or deny future programs as appropriate at that time. Nor should it constrain the Company's ability to evaluate future programs that may be reasonable and in the public interest.

Q. PLEASE RESPOND TO MR. KOLLEN'S CRITICISM THAT THE EV PILOT WILL BE MANAGED BY ANOTHER DUKE AFFILIATE, NOT DUKE ENERGY KENTUCKY.

A. While Mr. Kollen states that the Pilot programs will be managed by another Duke Energy affiliate and not an employee of Duke Energy Kentucky or Duke Energy Ohio, this is inaccurate. This project will be owned and operated by Duke Energy Kentucky like any other utility asset. Duke Energy has a service company, Duke Energy Business Services LLC., (DEBS) that is permitted to provide services to the regulated utilities in the Duke Energy family. Similarly, Duke Energy Kentucky's other regulated utility affiliates have Commission-approved service agreements that permit employees, particularly those with specific subject matter expertise, to perform services for the regulated utility affiliate with costs directly assigned to that utility. The fact that DEBS employees, or even employees of another utility affiliate pursuant to a Commission-approved service agreement, provide such services does not change the fact that the asset itself is owned and operated by Duke Energy Kentucky. Rather, it actually is an efficient use of resources insofar as it allows Duke Energy Kentucky to only incur an allocated portion of the costs of such personnel instead of hiring a separate and independent staff.

Q. WILL ALL CUSTOMERS BENEFIT FROM THE EV PILOT?

A. Yes. While Mr. Kollen argues without evidence that the EV Pilot programs will not benefit all customers, the Company has illustrated the long-term potential for downward rate pressure from EV growth with managed charging. Attachment LWR-1 shows in clear economic terms the potential future benefit from increasing EV adoption and properly managing EV charging load in Kentucky. As shown in the "80x50" scenario, EV charging could provide $24 million annually in net revenue benefits across Kentucky assuming managed charging. While the benefit to Duke Energy Kentucky customers would be less than the statewide total, there is clear reason to believe significant benefits to all Duke Energy Kentucky customers can be accrued by increasing EV growth and managing charging. The Pilot is necessary to gather the relevant data and prove out programmatic features to address charging different types of EVs, which are crucial for the company to develop permanent programs which secure the potential benefits for all customers of increasing EV growth.

Q. PLEASE RESPOND TO MR. KOLLEN'S CRITICISMS OF POTENTIAL ELECTRIC VEHICLE CHARGING HAVING SIGNIFICANT IMPACT ON SYSTEM CAPACITY AND EXPLAIN WHY THE EV PILOT IS NECESSARY.

A. This argument is short-sighted and fails to consider the risk of inaction by the Company in the face of a growing source of new load. The Company already accounts for forecasted EV growth through 2040 in the Integrated Resource Planning process, and therefore already accounts for EV load in the capacity position for the Company through the Pilot term. Over the longer term, cost-effectively managing new EV load to the benefit of Duke Energy Kentucky customers is precisely the goal of the Pilot. The Company must gather data to develop future programs which manage EV charging load and mitigate peak load impacts. The Company's operating capacity position is another fact in favor of fully exploring the impact, costs, and benefits of EV charging along with developing programs to manage this growing source of new load. If the Company does not develop such procedures, there is a risk that future EV growth could create higher costs for all customers by driving up peak demand.

Q. WHY SHOULD DUKE ENERGY KENTUCKY BE PERMITTED TO OWN AND OPERATE A LIMITED NUMBER OF EV CHARGING STATIONS?

A. Mr. Kollen argues that if EV programs are a priority, the Commission should look to private industry to develop this infrastructure and assume the risks and costs. In fact, the EV Pilot programs have many features which allow for private market participation across many of the segments including the Residential, Commercial, and Non-Road EV segments. The Company is proposing to own and operate the DC Fast Chargers for this Pilot-stage program in order to protect customers against stranded assets, ensure that the Fast Chargers are installed in a timely manner and maintained in good working order throughout their full useful life. The Company has shown that private industry is not deploying charging infrastructure at the scale necessary to support advanced EV market growth. Attachment LWR-Rebuttal-1 Jan 2020 EV Charging Station Count clearly indicates the lack of private investment by showing that only fifteen Level 2 and one DCFC charging stations that are 24 hour accessible and non-proprietary are currently deployed in the Duke Energy Kentucky service territory. When expansion of charging infrastructure is funded as a utility program, it is of vital importance that the infrastructure funded remains used and useful throughout the full life of the asset. The only way to ensure this is for the Company to own and operate fast charging infrastructure. There are many examples across the country from various grant programs where charging infrastructure – particularly DC fast charging infrastructure – has fallen into disrepair or been removed entirely because the operators were unwilling or unable to maintain the infrastructure in good working order. The Company can protect against the risk of funding stranded assets and ensure all DCFC funded by the programs remains in good working order for public benefit.

Q. PLEASE EXPLAIN WHY THE COMPANY'S EV PILOT IS IN THE PUBLIC INTEREST AND SHOULD BE APPROVED BY THE COMMISSION.

A. While Mr. Kollen's criticisms focus on the narrow economics of individual programs, the Company urges the Commission to take a broader system view of the benefits to all customers from EV adoption as well as the risk of inaction at this early stage of market growth. To concentrate on only short-term economics of the Pilots ignores the potential for EVs to create higher future costs for Duke Energy Kentucky customers if Duke Energy Kentucky is not allowed to properly prepare programs addressing this new source of load. Constraining these Pilot programs to a simple economic payback over a short time frame with a limited number of participants misses the broader purpose of these Pilot programs. By developing these programs now, Duke Energy Kentucky can determine the costs and benefits of different types of EV charging and can develop procedures to cost-effectively integrate this load. Without these programs, the Company is essentially flying blind to an emerging technology with the potential to create much larger costs for Duke Energy Kentucky customers in the future. The Commission should consider not simply the cost of the EV Pilot, but also potential future costs incurred if the Company does not develop sufficient capacity to manage EV charging load before EV growth reaches significant levels. Developing a comprehensive understanding and suite of offerings to address this growing market segment is therefore in the public interest and should be approved. Duke Energy Kentucky is proposing to the Commonwealth and the Public Service Commission an opportunity to be involved with an emerging technology in a measured and controlled manner while at the same time deploying the foundational electric vehicle charging infrastructure needed in northern Kentucky.

Q. SHOULD THE COMMISSION APPROVE DUKE ENERGY KENTUCKY'S EV PILOT PROJECTS AND REJECT MR. KOLLEN'S RECOMMENDATION TO REDUCE THE COMPANY'S PROPOSED REVENUE REQUIREMENT BY $.145?

A. Yes. For the reasons I've discussed above, the Commission should reject Mr. Kollen's recommendation and approve the EV Pilot.

III. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

Rebuttal Attachment LWR-Y Jan 2020 EV Charging Station Count

Fuel Type	Station Name	Street Address	City	Groups With Access Code	Access Days Time		# of Level 1	# of Level 2	# of DCFC	EV Network	EV Pricing
ELEC	Kerry Nissan	8053 Burlington Pike	Florence	Private				1		Non-Networked	
ELEC	Cincinnati Northern Kentucky International Airport	2939 Terminal Dr	Hebron	Public	24 hours daily; pay lot		4			Non-Networked	Free
ELEC	Cincinnati Northern Kentucky International Airport	2939 Terminal Dr	Hebron	Public	24 hours daily; pay lot		4			Non-Networked	Free
ELEC	FASTPARK	609 Petersburg Rd	Hebron	Public	24 hours daily			8		ChargePoint Network	Free
ELEC	Walmart	7625 Doering Dr	Florence	Public - Card key at all times	24 hours daily			2	1	eVgo Network	
ELEC	NKU-HIC	Kenton Dr	Newport	Public	24 hours daily			2		ChargePoint Network	Free
ELEC	HIEX FLORENCE	1045 Vandercar Way	Florence	Public	24 hours daily			2		ChargePoint Network	Free
						Total Port Count:	-	**15**	**1**		

Source: https://afdc.energy.gov/stations/#/station/65406

VERIFICATION

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

The undersigned, Lang W. Reynolds, Director Electrification Strategy, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing rebuttal testimony and that it is true and correct to the best of his knowledge, information and belief.

Lang W. Reynolds Affiant

Subscribed and sworn to before me by Lang W. Reynolds on this 13 day of January, 2020.

Shelvona L. Sears

NOTARY PUBLIC

My Commission Expires:

SHELVONA L. SEARS
My Commission Expires
NOTARY PUBLIC
February 6, 2023
GASTON COUNTY, NC

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2019-00271

REBUTTAL TESTIMONY OF

JEFFREY R. SETSER

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

January 31, 2020

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeffrey R. Setser, and my business address is 550 South Tyron Street, Charlotte, North Carolina 28202.

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

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

Q. ARE YOU THE SAME JEFFREY R. SETSER THAT FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

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

A. The purpose of my Rebuttal Testimony is to address the erroneous claims and adjustments made by the Attorney General's witness Lane Kollen related to the Cost of Capital of DEBS and his proposal to amortize the excess deferred income taxes (EDITs) attributed to DEBS as a one-time refund or credit to customers.

II. DISCUSSION

Q. PLEASE DESCRIBE MR. KOLLEN'S RECOMMENDED ADJUSTMENT RELATED TO THE COST OF CAPITAL OF DEBS.

A. Mr. Kollen's discussion related to the cost of capital related to DEBS begins on page 38 of his testimony. He recommends a reduction in Duke Energy

Kentucky's electric revenue requirement of $0.679 million to eliminate the Company's share of a return on DEBS assets, arguing that DEBS cost of capital should be limited to interest on short-term intercompany debt.

Q. DOES DUKE ENERGY KENTUCKY AGREE WITH THIS RECOMMENDATION?

A. No.

Q. PLEASE EXPLAIN.

A. Including a return on DEBS assets in test period expenses is in accordance with the Company's Cost Allocation Manual (CAM). The Duke Energy Kentucky CAM states that "by the terms of the Service Company Utility Service Agreement, compensation for any service rendered by the Service Company to its utility affiliates is the fully embedded costs thereof (*i.e.*, the sum of: (i) direct costs, (ii) indirect costs; and (iii) costs of capital)." Any reasonable interpretation of the term 'costs of capital' would include a return on ALL of the components of capitalization. DEBS' capitalization includes debt and equity; so, just like any of the regulated utilities, the cost of capital would be the weighted average of all costs of capital. An argument about what the fair return on equity (ROE) on DEBS should be is a fair argument but it is certainly not fair to say that the return on equity for DEBS common equity is 0%.

Prior to the return on DEBS assets being applied, efforts were made to try and apportion common assets to each of the participating jurisdictions when the assets were placed in service. This would result in the return for each jurisdiction being applied to those assets as they were on the utility books. The current method for calculating the return on DEBS' assets is replicating this approach. Alternatively, certain jurisdictions had also been allocated a pro forma share of the assets on DEBS in the calculations for rate base in the regulatory filings and rate cases. The current approach eliminates the needs for these methods and simply uses a revenue requirement based on each jurisdiction's allowed return for the use of common assets, which are used to provide service to customers.

Q. EVEN IF THE COMMISSION WERE TO AGREE WITH MR. KOLLEN'S POSITION THAT THE COMPANY SHOULD ONLY RECOVER THE DEBS' COST OF CAPITAL AT THE DEBT RATE, IS MR. KOLLEN'S ADJUSTMENT NECESSARY?

A. No.

Q. PLEASE EXPLAIN.

A. Regardless of whether Mr. Kollen's opinion was correct, the Company inadvertently excluded the entire return on DEBS' assets from its test period expenses. As noted in response to discovery question AG-DR-01-039, "in the process of responding to this discovery question, the Company discovered that it had inadvertently excluded $914,966 of intercompany A&G rent expense in Account 931008, from the test period." This account is where the return on DEBS assets is recorded in its entirety. As a result, Mr. Kollen's recommended adjustment to eliminate a return on DEBS' assets is moot. Accepting Mr. Kollen's adjustment would effectively eliminate a component of the Company's revenue requirement that does not exist.

Q. IS THE COMPANY REQUESTING TO MODIFY ITS PROPOSED TEST YEAR REVENUE REQUIREMENT TO CORRECT THIS INADVERTENT OMISSION?

A. No. For the reasons I discussed above, it is appropriate and reasonable for retail rates to reflect a return component on assets that provide service to customers. Nevertheless, as discussed in the rebuttal testimony of Ms. Sarah Lawler, the Company is NOT requesting to revise its revenue requirement upwards for the inadvertent omission. Therefore, even if the Commission agrees with Mr. Kollen's rationale for excluding DEBS' costs of capital from retail rates, there is no need for any downward adjustment to the revenue requirement because no return component related to DEBS was actually included in the test year revenue requirement.

Q. PLEASE EXPLAIN MR. KOLLEN'S RECOMMENDATION RELATED TO EDITS FOR DEBS.

A. Mr. Kollen's discussion of this recommendation begins on page 41 of his Direct Testimony. He recommends that Duke Energy Kentucky's revenue requirement be reduced be reduced by $0.215 to provide a one-time credit or refund attributed to the EDITs.

Q. DOES DUKE ENERGY KENTUCKY AGREE WITH MR. KOLLEN'S RECOMMENDATION?

A. No. The Commission should reject Mr. Kollen's recommendation.

Q. PLEASE EXPLAIN.

A. Mr. Kollen is incorrect in his discussion on the charging of income tax expense to Duke Energy Kentucky.

Q. PLEASE EXPLAIN HOW DEBS ALLOCATES INCOME TAX EXPENSE.

A. DEBS does not allocate out income tax expense, current or deferred.

Q. IS MR. KOLLEN'S TESTIMONY PROPOSING TO REFUND THE EDIT TO THE COMPANY AND OTHER AFFILIATE COMPANIES JUSTIFIED?

A. No. The current income taxes expense is a result of the return on DEBS assets for which the jurisdictions have a corresponding current deduction. Deferred income tax assets or liabilities are considered temporary differences and have always been maintained at DEBS. Therefore, any adjustments to deferred income taxes through the income statement should remain on DEBS. The depreciation for DEBS assets that is charged out to the utilities is based on straight-line book depreciation. Bonus and MACRS depreciation is a tax adjustment resulting in deferred tax liabilities that are not allocated out to the jurisdictions.

Prior to the Cinergy Service Company (DESS) being merged with Duke Energy Business Services (DEBS) on July 1, 2008, the DESS service company did allocate out income tax expense. At the point that DESS merged into DEBS, the company had a deferred tax asset of $109 million. The jurisdictions received the benefit of this, but the reversal of this asset stayed on DEBS. The jurisdictions have not been charged for this tax expense and we currently are not seeking reimbursement.

The return on rate base Mr. Kollen refers to is a calculation based on an apportionment of DEBS assets to Duke Energy Kentucky and the equity return is grossed up for taxes to arrive at a pre-tax amount. This calculation results in a monthly journal entry that creates current taxable income on DEBS and a current deductible expense for the jurisdiction. In 2018 the gross-up was adjusted for the change in federal income tax rates from 35% to 21%. Therefore, there are no deferred taxes that need to be adjusted or distributed as part of this process.

Q. DO YOU BELIEVE THE TWO ADJUSTMENTS MR. KOLLEN IS MAKING RELATED TO DEBS ARE CONGRUENT?

A. No. In fact, his adjustments are conflicting and undermine each other. On the one hand, Mr. Kollen is suggesting that Duke Energy Kentucky's customers should not be required to bear the full cost of equity (*i.e.*, income) for DEBS. Accordingly, it would be very inappropriate to then also flow through to customers EDITs recorded on DEBS books. The EDITs are exclusively generated by taxable income differences from book income. If Mr. Kollen's recommendation is approved, then customers are responsible for only the cost of short-term debt, *i.e.*, there is no taxable income. It would be wildly unfair, and punitive to the Company to both find that customers are not responsible for Duke Energy Kentucky's share of a return on DEBS assets and, at the same time, refund them for a tax benefit on income they aren't responsible for paying.

III. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

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

The undersigned, Jeffrey R. Setser, Director of Allocations and Reporting, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing rebuttal testimony and that it is true and correct to the best of his knowledge, information and belief.

Jeffrey R. Setser

Jeffrey R. Setser Affiant

Subscribed and sworn to before me by Jeffrey R. Setser on this 15 day of January, 2020.

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

Virginia M. Adams

NOTARY PUBLIC

My Commission Expires: 10/2/21

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)	Case No. 2019-00271

REBUTTAL TESTIMONY

OF

JOHN J. SPANOS

ON BEHALF OF

DUKE ENERGY KENTUCKY

January 31, 2020

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania, 17011.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. I previously submitted direct testimony on behalf of Duke Energy Kentucky on August 9, 2019.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the direct testimony of Kentucky Office of the Attorney General (AG) witness, Mr. Lane Kollen.

Q. WHAT ARE THE SUBJECTS OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony relates to depreciation issues, specifically the net salvage estimates for the steam and other production facilities; the life span for the Woodsdale facility; and the importance of updating the depreciation study.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Mr. Kollen's recommendation is to reject the Depreciation Study in its entirety and any changes proposed to the currently approved depreciation rates for Duke Energy Kentucky. His "alternatives" to wholesale rejection of the Study are to extend the life span of the Woodsdale CTs and eliminate the contingency and escalation components from the terminal net salvage estimates for production. My rebuttal testimony will discuss the flaws of these alternatives and address Mr. Kollen's claim that the Depreciation Study is unnecessary.

I also note that, while the depreciation study results in an increase in depreciation expense, most of this increase is not due to changes to service lives and net salvage recommended in the study. Instead, most of the increase is due to large capital additions at the Company's generating facilities. That is, my recommended lives and net salvage are not factors that cause most of the changes in depreciation expense. Indeed, for terminal net salvage and life span estimates, which are the two parameters Mr. Kollen specifically challenges, my proposals are either the same as or substantially similar to those approved by the Commission two years ago. In contrast, despite Mr. Kollen's protests that depreciation rates should remain unchanged, he has actually proposed significant changes in the terminal net salvage estimates and life span estimates recently approved by the Commission.

II. NET SALVAGE ESTIMATES FOR PRODUCTION

Q. WHAT ARE MR. KOLLEN'S OBJECTIONS TO THE TERMINAL NET SALVAGE ESTIMATES FOR STEAM AND OTHER PRODUCTION FACILITIES?

A. Mr. Kollen has two primary objections to the development of terminal net salvage estimates in this case: 1) He claims that the contingency costs included in the site-specific decommissioning studies are inappropriate since they are "uncertain and unknown."[1] 2) He asserts that the escalation of decommissioning costs to the date of retirement "forces today's customers to subsidize future customers."[2] Neither of these claims are correct, and Mr. Kollen provides no evidence to support their merit.

[1] Kollen p. 51, line 13.
[2] Kollen p. 52, line 13.

Q. DO THE COMPANY'S CURRENT DEPRECIATION RATES APPROVED BY THE COMMISSION INCLUDE BOTH CONTINGENCY AND ESCALATION?

A. Yes. In the Company's previous depreciation study, the terminal net salvage estimates included both contingency and escalation and were developed in the same manner as in the instant case. The Commission approved the Company's proposals with regard to terminal net salvage:

> The Commission finds Dukes Kentucky's recommendation on the treatment of terminal net salvage value in the computing the depreciation rates for generating units is reasonable in order to avoid intergenerational inequity and should be approved.[3]

Q. DOES MR. KOLLEN PROVIDE SUPPORT FOR HIS PROPOSAL TO EXCLUDE CONTINGENCY FROM THE DECOMMISSIONING ESTIMATES?

A. No. Mr. Kollen provides only speculation and false claims related to the contingency costs. He asserts that the contingency "simply increases the estimated decommissioning cost above the best estimate,"[4] and then theorizes that this

[3] Order in Case No. 2017-00321, p. 27

[4] Kollen p. 50, line 5.

"increase" is possibly a plan on the part of the firm that prepared the Decommissioning Study (Burns and McDonnell) to cash in on their overestimation of demolition costs. This is patently false and supported purely by conjecture.

Q. ARE CONTINGENCY COSTS A CONSISTENT COMPONENT OF DECOMMISSIONING COSTS?

A. Yes. The decommissioning estimates developed by Burns and McDonnell (BMcD) are site-specific using quantities and parameters unique to each facility and include data such as current market pricing for labor rates and equipment and scrap value for metals and other materials. The decommissioning costs from the BMcD study are carefully prepared with the goal of providing the best estimate of what contractors would bid for performing decommissioning tasks.

The contingency cost is a specific component of the total decommissioning estimate and not, as Mr. Kollen represents, an arbitrary amount added onto an otherwise complete estimate. BMcD has described the contingency as a reasonably expected cost to be incurred during the process of decommissioning. There is a degree of uncertainty associated with decommissioning and demolition of a facility and the contingency is a means of accounting for this expected uncertainty. Examples include weather delays, unknown environmental contamination, discovery of undocumented equipment or site conditions, or a need for additional site dewatering. Experience has proven these uncertainties to be an anticipated component of dismantlement, therefore, it is reasonable to include them in an estimate of decommissioning costs.

Q. WILL MR. KOLLEN'S PROPOSAL TO ELIMINATE ESCALATION PROPERLY ALLOCATE THE COMPANY'S COSTS OVER THE SERVICE LIVES OF THEIR GENERATING FACILITIES?

A. No. The decommissioning study prepared by BMcD uses costs at current price level. However, the Company's plants will not be retired for many years. The net salvage costs need to be escalated to the date of retirement so that the correct amounts are recovered over the lives of the plants. Mr. Kollen's proposal to remove escalation from the decommissioning costs is insufficient to fully recover the Company's costs.

Q. ARE MR. KOLLEN'S NET SALVAGE PROPOSALS BASED ON WIDELY ACCEPTED DEPRECIATION PRACTICES?

A. No. It is widely accepted that depreciation should include future net salvage costs, which are recovered on a straight-line basis and that those costs should be based on the expected cost to retire the Company's assets at the time of retirement or removal. This applies to decommissioning costs as well as to mass property assets.

Q. SHOULD NET SALVAGE BE BASED ON THE FUTURE COSTS EXPECTED TO BE INCURRED, NOT ON TODAY'S COSTS?

A. Yes. Because net salvage must be based on future costs, decommissioning costs for net salvage must also be estimates of the future cost at the time of decommissioning. For this reason, if decommissioning estimates are developed using the cost to decommission a plant today, then these costs must be escalated to the time period in which they are expected to be incurred.

Q. DO ANY AUTHORITATIVE DEPRECIATION TEXTS SUPPORT REPRESENTING FUTURE COST IN THE NET SALVAGE ESTIMATE?

A. Yes. Two widely cited, preeminent depreciation texts are the NARUC Public Utility Depreciation Practices (NARUC) and *Depreciation Systems* by Wolf and Fitch (Wolf and Fitch). Both texts are clear that net salvage should be included in depreciation as a future cost. I discuss these texts below. However, a full discussion of this topic, with specific references from these texts, was provided in my rebuttal testimony from the previous Duke Energy Kentucky electric rate case (Case No. 2017-00321), attached here as Attachment JJS-Rebuttal-1.

Q. WILL THE AG'S PROPOSAL PROPERLY ALLOCATE THE COMPANY'S COSTS OVER THE SERVICE LIVES OF THEIR GENERATING FACILITIES?

A. No. The decommissioning study prepared by BMcD used costs at today's price level. However, the Company's plants will not be retired for many years. The net salvage costs need to be escalated so that the correct amounts are allocated over the lives of the plants. Mr. Kollen's proposal to remove escalation from the decommissioning costs is insufficient to recover the Company's costs.

Q. PLEASE PROVIDE AN EXAMPLE THAT ILLUSTRATES WHY COSTS MUST BE ESCALATED TO THE DATE OF RETIREMENT.

A. Consider the following example. Assume a Company has a power plant that cost $1,000,000 to construct, will be in service for 40 years, and the net salvage is negative 10 percent. The negative 10 percent represents the cost at retirement, and so in year 40 it will cost $100,000 to decommission the plant. Additionally, assume that inflation occurs at a rate of 2.5 percent. Using the straight-line method, the resulting depreciation accrual would be \$27,500 and a depreciation rate of 2.75 percent. This is the proper amount needed to recover the full \$1,100,000 over the 40-year life of the power plant.

If instead decommissioning costs were not escalated to the date of retirement, the resulting depreciation rate would not recover the plant's original cost plus the cost to decommission it upon retirement. Consider the calculation of depreciation at year 1, when the asset is placed in service. The decommissioning cost of \$100,000 stated in year 1 dollars is only \$37,243. This is the amount that the other parties recommend should be included in depreciation expense for the Company's power plants, and their methodology would produce only \$25,931 in depreciation expense and a depreciation rate of 2.59 percent. Using such a method will not recover the full-service value (the plant's original cost + decommissioning costs) that the company should be allowed to recover through depreciation. Instead, the Company will only recover \$1,037,243 through depreciation expense and will recover less than 40 percent of the actual net salvage costs for the plant. This represents \$62,757 less than the full-service value of the plant that the Company is entitled to recover.

Q. SHOULD NET SALVAGE BE RECOVERED IN TODAY'S COST (*I.E.* THE COST IN TODAY'S DOLLARS)?

A. No. In order to recover the service value of the Company's assets, net salvage must be determined at the cost that will be incurred in the future. When using the straight-line method of depreciation, these costs are recovered ratably, or in equal amounts each year, over the life of the Company's plant.

Q. IS RECOVERING THE FUTURE COST OF NET SALVAGE CONSISTENT WITH THE FERC USOA?

A. Yes. The FERC USOA specifically defines net salvage as follows:

> 19. Net salvage value means the salvage value of property retired less the cost of removal.

Cost of removal is defined as:

> 10. Cost of removal means the cost of demolishing, dismantling, tearing down or otherwise removing electric plant, including the cost of transportation and handling incidental thereto. It does not include the cost of removal activities associated with asset retirement obligations that are capitalized as part of the tangible long-lived assets that give rise to the obligation. (See General Instruction 25).

Finally, cost is defined as (emphasis added):

> 9. Cost means the <u>amount of money actually paid</u> for property or services. When the consideration given is other than cash in a purchase and sale transaction, as distinguished from a transaction involving the issuance of common stock in a merger or a pooling of interest, the value of such consideration shall be determined on a cash basis.

Read together, it should be clear from these definitions that the USOA specifies that cost of removal, which as part of net salvage must be recovered through depreciation expense, is the actual amount that is paid at the time of the transaction. Because net salvage will occur in the future, it is an estimate of the future cost that must be included in depreciation rates.

Q. DO GENERALLY ACCEPTED DEPRECIATION CONCEPTS SUPPORT THAT THE NET SALVAGE IN DEPRECIATION SHOULD BE INCLUDED AT THE COST THAT WILL BE INCURRED?

A. Yes. Including the future cost of net salvage for plant accounts is consistent with established depreciation concepts. Depreciation is a cost allocation concept, in which the full cost of an asset (original cost less net salvage) is allocated on a straight-line basis over the period of time an asset will be in service.

Q. DO ANY AUTHORITATIVE DEPRECIATION TEXTS SUPPORT THAT THE NET SALVAGE AMOUNT SHOULD REPRESENT THE FUTURE COST?

A. Yes. NARUC states the following:

> [U]nder presently accepted concepts, the amount of depreciation to be accrued over the life of an asset is its original cost less net salvage. Net salvage is difference between the gross salvage that will be realized when the asset is disposed of and the cost of retiring it.[5] (Emphasis added)

NARUC also explains that:

> The goal of accounting for net salvage is to allocate the net cost of an asset to accounting periods, making due allowance for the net salvage, positive or negative, that will be obtained when the asset is retired. This concept carries with it the premise that property ownership includes the responsibility for the property's ultimate abandonment or removal. Hence, if users benefit from its use, they should pay their pro rata share of the costs involved in the abandonment or removal of the property and also receive their pro rata share of the benefits of the proceeds received.[6] (Emphasis added)

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[5] NARUC Manual at 18.
[6] NARUC Manual at 18.

Wolf and Fitch is another highly regarded, authoritative depreciation text. The authors are clear that net salvage should be included in depreciation and that it should be recognized as a future cost. Wolf and Fitch explain that:

> The matching principle specifies that all cost incurred to produce a service should be matched against the revenue produced. Estimated future costs of retiring an asset currently in service must be accrued and allocated as part of the current expenses.[7]

III. LIFE SPAN FOR OTHER PRODUCTION

Q. WHAT IS THE CURRENT LIFE SPAN FOR THE COMPANY'S WOODSDALE FACILITY?

A. The Woodsdale CTs were placed in service in 1992, with an estimated life span of 40 years, and proposed retirement date of 2032.

Q PLEASE SUMMARIZE MR. KOLLEN'S LIFE SPAN PROPOSAL FOR THE WOODSDALE FACILITY.

A. Mr. Kollen proposes extending the life span for Woodsdale to 50 years based on his predictions of the Company's plans and a random sampling of CT life spans. Mr. Kollen cites a lack of evidence that the facility "will become uneconomic in 2032" and that "the Company has no present plans to retire" them[8] as bases for arbitrarily increasing the life span by 10 years.

[7] Wolf and Fitch, p. 7.
[8] Kollen, p. 56, lines 10-11.

Q. IS THERE SUPPORT FOR CHANGING THE CURRENTLY APPROVED LIFE SPAN FOR THE WOODSDALE CT UNITS?

A. No. The estimated life span for a production facility is based on various factors including the plant capacity, the owner's planned usage and maintenance, the manufacturer's life expectations for the components, and prevailing technologies and regulations. The life span for the Woodsdale facility was estimated at 40 years based on a unique set of these planning factors and without clear or significant changes to those factors, there is no compelling reasoning for altering the life span.

Q. IS THE LIFE SPAN USED IN THE CURRENT DEPRECIATION STUDY THE SAME AS THE LIFE SPAN USED IN THE COMPANY'S CURRENT DEPRECIATION RATES?

A. Yes.

IV. RELEVANCE OF UPDATING DEPRECIATION RATES

Q. PLEASE ADDRESS THE AG'S CLAIM THAT UPDATING THE DEPRECIATION RATES IS "UNDULY AGGRESSIVE AND UNNECESSARY."[9]

A. As Mr. Kollen notes, the depreciation rates developed in a study such as mine are generally reasonable for a period of three to five years. This does not suggest, however, that more frequent updates of rates are unwarranted or unnecessary in some cases. The nature of depreciation calculations is such that adjustments could be made more frequently to more appropriately align the actual depreciation to changes in

[9] Kollen, p. 48, lines 8-9.

utilization of assets.

Q. HAVE MANY UTILITIES IN RECENT YEARS CONDUCTED DEPRECIATION STUDIES MORE FREQUENTLY THAN THREE TO FIVE YEARS?

A. Yes. The nature of assets and their life and salvage characteristics are more commonly affected by forces other than physical age and wear and tear. Forces of retirement such as obsolescence, technology and regulations have a much bigger impact on life and net salvage characteristics. These forces can be more frequent and impactful than review every three to five years.

Q. HAVE OTHER DUKE ENTITIES CONDUCTED UPDATED DEPRECIATION STUDIES MORE FREQUENTLY THAN A THREE TO FIVE YEAR CYCLE?

A. Yes.

Q. THE PURPOSE OF A DEPRECIATION STUDY IS TO MATCH RECOVERY TO UTILITIZATION OF ASSETS. DOES UPDATING A DEPRECIATION STUDY DURING A RATE CASE MEET THIS OBJECTIVE?

A. Yes. As shown in the depreciation study, the life and net salvage characteristics have changed, therefore, an update of these parameters better matches future recovery to asset utilization. Additionally, for life span property, the Company has added property to its generating facilities. All else equal, these types of additions typically result in an increase in depreciation rates even if life and net salvage estimates do not change because new additions have to be recovered over the remaining life span of the facility.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes. It does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief.	)	Case No. 2017-00321

REBUTTAL TESTIMONY

OF

JOHN J. SPANOS

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

February 14, 2018

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania, 17011.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. I previously submitted direct testimony on behalf of Duke Energy Kentucky on September 1, 2017.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the direct testimony of Kentucky Office of the Attorney General (AG) witness, Mr. Lane Kollen.

Q. WHAT ARE THE SUBJECTS OF YOUR REBUTTAL TESTIMONY?

A. The subjects of my rebuttal testimony relate to the most appropriate depreciation methods for establishing depreciation rates. Specifically, while I have used widely accepted methods and approaches to depreciation, Mr. Kollen has proposed significant changes from the methods currently used for the Company's depreciation rates. The first subject I will address relates to various components of net salvage. The second subject is the utilization of the Equal Life Group (ELG) procedure.

Q. PLEASE SUMMARIZE THESE DEPRECIATION ISSUES.

A. My testimony will respond to the depreciation related proposals of AG witness, Kollen, as mentioned above. There is no opposition to the service lives or probable retirement dates of any asset class. Mr. Kollen did not perform a depreciation study nor did he analyze transactional data. However, he does develop alternative depreciation expense levels which I will address. Specifically, my testimony sets forth the following depreciation issues:

- The Attorney General proposes to defer the recovery of net salvage after the Company's assets have been retired. That is, he proposes to not allow for the recovery of future net salvage prospectively through depreciation rates. In general, his net salvage proposals and overall approach violates the requirements of the Uniform System of Accounts (USOA), is not consistent with widely accepted depreciation practices, and is a significant departure from prior practices of the Company and other Kentucky utilities. Specifically, the Attorney General makes two different, but related, proposals for net salvage:
    - The Attorney General proposes to eliminate the terminal net salvage component for generating facilities. This is inconsistent with current practices for Duke Energy Kentucky and is inconsistent with proper recovery practices set forth in the USOA.
    - For interim net salvage for production plant and for net salvage for all non-production plant accounts, the Attorney General proposes to defer the recovery of net salvage until the Company's assets are retired. This approach is also inconsistent with the USOA, which requires the recovery of net salvage over the service lives of the Company's assets
- The Attorney General has proposed to utilize the Average Life Group (ALG) procedure as compared to the more accurate ELG procedure. The ELG

procedure, which is currently used for the Company's depreciation rates, more accurately matches the recovery of the assets to the utilization of the assets while in service.

II. NET SALVAGE

A. INTRODUCTION

Q. WHAT IS NET SALVAGE?

A. Net salvage, as used in depreciation, is defined as gross salvage less cost of removal. When an asset is retired it may have scrap or reuse value, which is gross salvage. There is also a cost to retire the asset. For example, the retirement of a distribution pole typically requires a multiple person crew and heavy equipment to remove the pole from the ground and cut the pole for disposal. There also may be disposal costs for the pole. All of these costs associated with the retirement are cost of removal.

Most types of utility property typically experience negative net salvage, meaning that cost of removal exceeds gross salvage. Examples may include the cost to remove a pole during a pole replacement project or the cost to decommission a power plant after retirement. These costs need to be recovered over the period of time the assets are in service.

Q. IS NET SALVAGE INCLUDED IN DEPRECIATION?

A. Yes. Net salvage is part of the service value, or overall cost, of an asset. In order to equitably allocate the full cost of an asset over its service life, net salvage must be estimated while the asset is still in service and allocated over the life of the asset. If, instead, the recovery of net salvage costs are deferred until (or after) the asset is retired, then future customers will have to pay the full net salvage cost for an asset that is no longer in service. This is the approach Mr. Kollen has proposed and his approach results in intergenerational inequity by forcing future customers to pay the costs of assets from which they will not receive electric service.

Q. MR. KOLLEN DISCUSSES "THREE APPROACHES" TO NET SALVAGE ON PAGES 36 THROUGH 38 OF HIS TESTIMONY. WHAT ARE THE APPROACHES HE DISCUSSES?

A. Mr. Kollen sets forth three possible approaches for the recovery of net salvage. In summary, these approaches are as follows:

1. Net salvage is recovered through depreciation over the life of an asset;
2. No net salvage is included in depreciation; and
3. Net salvage is amortized over a period of time after the asset is retired.

What Mr. Kollen does not say is that only the first of these approaches is consistent with the USOA, is widely accepted, and results in intergenerational equity. The second and third approaches recover net salvage after an asset has been retired, which is not consistent with the USOA or widely accepted depreciation practices. Mr. Kollen has generally used the third approach.

Q. WHAT DOES THE USOA REQUIRE FOR NET SALVAGE?

A. In General Instruction 22, the USOA requires that

> Utilities must use a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property <u>over the service life</u> of the property. (Emphasis added)

Service value is defined as "the difference between original cost and net salvage value of electric plant."[1] Thus, the USOA is clear that net salvage must be allocated <u>over the service life</u> of utility property. Mr. Kollen's proposals do not meet this requirement. Instead, under his approach net salvage is "deferred" until when or after property is retired and his recommended depreciation rates do not include an estimate of "future net salvage."[2] Mr. Kollen's proposals, therefore, do not comply with the requirements of the USOA.

Q. ARE YOUR NET SALVAGE PROPOSALS FOR THE COMPANY BASED ON WIDELY ACCEPTED DEPRECIATION PRACTICES?

A. Yes.

Q. ARE THE AG'S NET SALVAGE PROPOSALS BASED ON WIDELY ACCEPTED DEPRECIATION PRACTICES?

A. No.

Q. HOW IS NET SALVAGE ESTIMATED IN A DEPRECIATION STUDY?

A. The method of estimating net salvage depends on the type of property. For power plants, the estimate is typically based on a decommissioning study. These costs are typically estimates of the cost to retire a facility today, and therefore need to be adjusted to estimate the cost that will be incurred in the future when the plant is actually retired.

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[1] FERC Uniform System of Accounts, definition 37.
[2] *See* Direct Testimony of Lane Kollen, p. 37, lines 18-21.

For interim net salvage for power plants, and for mass property accounts such as transmission and distribution plant accounts, net salvage estimates are based in part on statistical analyses of historical net salvage data. In this analysis, net salvage (as well as its components of gross salvage and cost of removal) is expressed as a percentage of retirements. This approach, which is widely-accepted in the industry and supported by depreciation textbooks, is referred to as the "traditional method."

Q. ARE YOUR ESTIMATES FOR NET SALVAGE CONSISTENT WITH THE APPROACHES USED FOR THE DEPRECIATION RATES CURRENTLY USED BY THE COMPANY?

A. Yes. The current depreciation rates for production plant incorporate estimates of decommissioning costs which are escalated to the time of retirement, as I have also done in the instant case. The current depreciation rates for mass property accounts are based on the traditional method of estimating net salvage. In both of these instances, the AG has proposed a change from the Commission's current practices for Duke Energy Kentucky's depreciation rates.

Q. HOW WILL YOU ADDRESS THE NET SALVAGE RECOMMENDATIONS OF MR. KOLLEN?

A. As discussed above, Mr. Kollen's proposals are not consistent with widely accepted depreciation concepts. I will discuss these issues in more detail, explain the ratemaking impacts of Mr. Kollen's proposals to defer the recovery of net salvage costs, and also address Mr. Kollen's alternate proposal to exclude the escalation of decommissioning costs to the time of retirement.

B. THE AG'S PROPOSAL IS NOT BASED ON WIDELY ACCEPTED METHODS

Q. IS THE METHOD YOU HAVE USED TO ESTIMATE NET SALVAGE WIDELY ACCEPTED IN THE ELECTRIC INDUSTRY?

A. Yes. The traditional method of recovering net salvage over the life of a Company's assets is used by the vast majority of regulatory commissions in the United States. Specifically:

- The traditional method meets the requirements of the FERC's Uniform System of Accounts, while the AG's method does not;
- The traditional method has been used for many depreciation studies in Kentucky, including for the Company's current depreciation rates;
- The traditional method is widely accepted in the industry in other jurisdictions, whereas the AG's method is not; and
- The traditional method is supported and endorsed by authoritative depreciation texts whereas the AG's method is not.

i. Uniform System of Accounts

Q. WHAT IS THE FERC USOA?

A. The USOA is the standard set of definitions, rules and instructions established by the FERC that provides consistency in accounting for utilities under its jurisdiction. Most jurisdictions, including Kentucky, have adopted the USOA for the utilities they regulate.

Q. DOES THE USOA ADDRESS THE ISSUE OF HOW NET SALVAGE COSTS SHOULD BE ACCOUNTED FOR, AND IF SO, HOW?

A. Yes. The USOA provides that net salvage costs should be accrued over the course of an asset's service life (*i.e.*, recognized in each period in which the asset provides service) in a systematic and rational manner.

Q. PLEASE DISCUSS IN MORE DETAIL THE USOA'S TREATMENT OF DEPRECIATION.

A. The USOA defines depreciation as follows:

> Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility 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 requirements of public authorities.[3]

Q. IN THE QUOTE ABOVE, THE USOA REFERS TO DEPRECIATION AS THE "LOSS IN SERVICE VALUE." WHAT IS SERVICE VALUE?

A. As discussed previously, service value, as defined in the USOA, is "the difference between original cost and net salvage value of electric plant."[4] Thus, the USOA requires that depreciation include net salvage as well as the original cost of the Company's assets in depreciation.

Q. DOES THE USOA ALSO DEFINE WHAT IT MEANS BY "NET SALVAGE VALUE"?

A. Yes. "'Net salvage value' means the salvage value of property retired less the cost of removal."[5] Net salvage is described as "positive net salvage" if the salvage value

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[3] FERC Uniform System of Accounts, definition 12.
[4] FERC Uniform System of Accounts, definition 37.
[5] FERC Uniform System of Accounts, definition 19.

exceeds removal costs, and described as "negative net salvage" (*i.e.*, a net cost) if removal costs exceed the salvage value. These costs are recorded to accumulated depreciation at the cost expended (or received as salvage) at the time they occur, but are included in depreciation expense over the service lives of the assets.

Q. DOES THE USOA PRESCRIBE A METHOD OF DEPRECIATION ACCOUNTING?

A. Yes. The electric USOA includes General Instruction 11, "Accounting to be on accrual basis," which states, "[t]he utility is required to keep its accounts on the accrual basis." Further, as discussed previously, General Instruction 22 in the Electric Uniform System of Accounts, "Depreciation Accounting," states:

> Utilities must use a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property over the service life of the property.

Q. WHAT IS THE ACCRUAL BASIS OF ACCOUNTING?

A. Under the accrual basis of accounting, transactions are counted when the order is made, the item is delivered, or the service occurs, regardless of when any money for such orders, items, or services is actually received or paid. The accrual basis recognizes economic events without regard to when the related cash transaction occurs. Thus, net salvage costs are traditionally recognized when the service is rendered – that is, during each year of an asset's service life - rather than when the actual salvage-related costs are incurred. Any method that recognizes net salvage costs after the costs are incurred would be inconsistent with the concept of accrual accounting, as the costs are recognized as an expense at a time when the asset is no longer rendering service.

Q. DOES THE AG'S METHOD ALLOCATE "IN A SYSTEMATIC AND RATIONAL MANNER THE SERVICE VALUE OF DEPRECIABLE PROPERTY OVER THE SERVICE LIFE OF THE PROPERTY?"

A. No. As I have discussed previously, the AG proposes to recover net salvage concurrent with or after the retirement of the Company's assets. It does not incorporate the future net salvage costs for assets that are currently in service and, therefore, does not allocate the service value of depreciable property over its service life.

ii. The Traditional Method of Net Salvage is Used in Most Jurisdictions, Including Kentucky

Q. WHAT NET SALVAGE METHODS ARE USED IN OTHER JURISDICTIONS?

A. The net salvage approach that I have used (*i.e.*, the first approach described by Mr. Kollen) is the predominate method accepted by the vast majority of jurisdictions in the United States. To my knowledge, the traditional method is accepted by the vast majority of U.S. states (including Kentucky) and by FERC.

Q. HAS MR. KOLLEN PROVIDED ANY EVIDENCE OF ANY U.S. JURISDICTIONS THAT USE HIS PROPOSED NET SALVAGE APPROACH?

A. No.

Q. HAVE THE METHODS YOU HAVE PROPOSED BEEN ACCEPTED PREVIOUSLY IN KENTUCKY?

A. Yes. Again, the current depreciation rates are based on the same methods I have used for net salvage in the instant case.

Q. ARE YOU FAMILIAR WITH ANY STATES THAT HAVE SPECIFICALLY REJECTED ALTERNATIVE PROPOSALS FOR NET SALVAGE, SUCH AS THAT PROPOSED BY THE AG, IN RECENT YEARS?

A. Yes. There are a number of states that have rejected proposals similar to the AG's. I will discuss four of these in my testimony.

Q. PLEASE ADDRESS THE ACCEPTANCE OF NET SALVAGE METHODS IN INDIANA.

A. In a 2004 case for an affiliate Company, PSI Energy (now Duke Energy Indiana), the Indiana Commission addressed the approach to recover net salvage for both mass property and production plant accounts, and also addressed the appropriateness of including future inflation in net salvage. Proposals of intervenors in that case were similar to those of Mr. Kollen for both decommissioning costs and for interim and mass property net salvage. For each of these issues, the Indiana Commission ruled in favor of the methods I have proposed in the instant case and rejected Mr. Kollen's proposals.

The Indiana Commission affirmed that net salvage should be included for production plant accounts, stating:

> The next issue is the timing of the collection of such costs. The parties did not disagree that dismantling costs are a part of the cost of current facilities providing current service. They disagreed as to the timing of the collection of such costs and their amount. This Commission can either find that current customers should pay a share of dismantling costs, which will not be incurred for a number of years, or, in the alternative, conclude that these costs should be passed on to a future generation of customers. This Commission does not believe that the latter alternative constitutes sound regulatory policy, or is based on sound ratemaking principles. Current customers are

> receiving service from PSI's generation facilities. A part of the costs of those facilities is dismantlement upon retirement. Therefore, we do not believe it would be appropriate for the Company to backload the dismantlement costs for future ratepayers to pay when the facilities associated with these costs are providing service to current customers. Rather, we find it is appropriate that these costs be shared by all customers that received service from PSI's generation facilities. Accordingly, this Commission finds that dismantlement costs are properly included in determining the depreciation rates approved in this cause.[6]

The Indiana Commission also affirmed that future net salvage estimates should incorporate future inflation, which supports my proposal to escalate the decommissioning costs to the time of retirement:

> The final issue regarding dismantlement costs is whether inflation should be factored into the dismantlement cost estimates to be utilized in determining PSI's depreciation rates. Mr. Selecky and Mr. Majoros objected to the use of inflation. Mr. Spanos utilized Mr. Wendorfs dismantlement costs which are stated in 2002 dollars, and factored inflation up to the year of the projected dismantlement as a factor in his consideration, along with his analyses of historical or interim retirements. We find Mr. Spanos' approach to be realistic and consistent with past experience. Inflation has been a fact of life in the American economy for many years. Not factoring inflation into dismantlement costs to be incurred in the future would understate those costs, with the result being that future customers would have to pay costs arising from facilities that are not serving them. This result flies in the face of matching rates with costs incurred for service. A sound ratemaking principle followed by this Commission. Moreover, current customers receive a benefit by factoring in inflation, as it may appropriately allow for a reduction in rate base because of the increased accumulated reserve for depreciation. Accordingly, this Commission finds that accounting for inflation in determining the

[6] Order 051804 in Indiana Cause No. 42359, Issued May 18, 2004, page 70.

> dismantlement estimates to be used as part of PSI's depreciation rates is reasonable.[7]

Finally, the Indiana Commission ruled against an approach similar to Mr. Kollen's proposal for interim and mass property net salvage. The Indiana Commission first explained the proposals of intervenor parties in that case:

> Turning to the net salvage values for transmission, distribution and general plant, Mr. Selecky and Mr. Majoros urged this Commission to utilize historical average of actual net salvage expense incurred by PSI for determining the net salvage to be utilized for these accounts and then expense these averages as a separate cost of service item. In effect, they are proposing that net salvage values be eliminated from the depreciation rates determination in this proceeding. In contrast, Mr. Spanos took the traditional approach and utilized estimated net salvage values for these accounts based on historical net salvage costs as a percent of the original cost of the retired assets that produced the gross salvage or required costs to remove. Mr. Majoros recognized that Mr. Spanos' approach was not abnormal, but he and Mr. Selecky cited a number of state commissions where an historical average approach had been adopted.[8]

The Indiana Commission rejected proposals of the intervenors in that case:

> We believe that there is a sound basis for the traditional approach on this issue that is utilized by a majority of states. Utilizing historical averages as an item to be expensed to current customers means that these customers will be paying for salvage costs at levels that may not be sufficient. That means that the next generation of customers will be paying for salvage costs related to facilities from which they may never have received service. The use of best estimates of future salvage costs addresses this inequity. Moreover, use of historical averages for dismantling costs does not take into account the current configuration of PSI's system with regard to its production, transmission, distribution and general facilities. Facilities in service 40-50 years ago did not take into account the significantly enhanced customer base that PSI now serves, nor the current configuration of

[7] Order 051804 in Indiana Cause No. 42359, Issued May 18, 2004, page 71.

> PSI's facilities that serve these customers. It seems appropriate to utilize best cost estimates for net salvage values taking into account specific facilities now serving PSI's customers in developing depreciation rates that today's customers should pay. Accordingly, we find that the use of historical averages for net salvage values with regard to transmission, distribution and general plant for the purpose of expensing them outside the context of the depreciation determination should be, and hereby is rejected.[9]

Q. PLEASE EXPLAIN THE ACCEPTANCE OF NET SALVAGE METHODS IN MISSOURI.

A. Missouri provides another example of a party making a net salvage proposal that was similar in concept to what Mr. Kollen has proposed. In the Missouri case, it was the commission staff that made such a proposal. However, the Missouri Public Service Commission (MPSC) rejected its Staff's proposal and affirmed the use of the traditional method that I have proposed in the instant case. The MPSC's Order in that case stated that:

> The Commission finds that Laclede has shown the accrual method to be just and reasonable and that Staff has failed to show that the Commission should adopt Staff's method of accounting for net salvage.[10]

Again, the MPSC Staff's proposal was similar in concept to what Mr. Kollen has proposed in the instant case. In the Laclede case, Laclede's proposal (referred to as the "accrual method" throughout the Laclede order) was the traditional method I have used in the depreciation study in the instant case.

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[8] Order 051804 in Indiana Cause No. 42359, Issued May 18, 2004, page 71.
[9] Order 051804 in Indiana Cause No. 42359, Issued May 18, 2004, pages 71-72.
[10] Missouri Case No. GR-99-315, Third Report and Order issued January 11, 2005, p. 16

The Laclede Order provides a number of important comments on the net salvage issue. First, the MPSC notes that while the utility had the burden of proof in the Laclede case, "Staff is the party advocating a change in the depreciation method used not only by Laclede, but almost all utilities in the country."[11] That is, the MPSC recognized that since the Missouri Staff was advocating a departure from widely accepted and longstanding depreciation practices, the Missouri Staff had an obligation to demonstrate why such a departure was appropriate. In the Laclede case, the Missouri Staff failed to provide justification for such a change, just as Mr. Kollen has failed to do so in the instant case.

Q. WHAT OTHER CONCEPTS DOES THE MPSC DISCUSS IN THE LACLEDE ORDER?

A. The MPSC discusses a number of important comments in its order. The MPSC recognizes that the traditional method is widely accepted, stating that:

> The accrual method has been used by Laclede and the Commission to determine Laclede's depreciation rates since at least the early 1950s. <u>It is undisputed that using the accrual method for this purpose is supported by the overwhelming weight of authority on such matters.</u> In both evidentiary hearings, Laclede and AmerenUE provided evidence showing the widespread support among depreciation professionals and authoritative texts for the traditional, or accrual, method of treating net salvage.
>
> Laclede and AmerenUE also established, and no party disputed, that such a method is consistent with the requirements of the Uniform System of Accounts that this Commission has adopted, and depreciation practices recognized and followed in all but a few regulatory jurisdictions in the United States. In contrast, Staff was unable to cite any depreciation practitioner, outside of other Staff

[11] *Id.* at 7.

> members, or any depreciation treatise that addressed its proposed treatment of net salvage. In addition, Staff was unable to adequately support or explain its reasoning for adopting this new approach.[12]

The MPSC also addressed the fact that net salvage accruals should be expected to be higher than current (or recent) net salvage expenditures. The MPSC stated:

> In criticizing the accrual method for determining net salvage, Staff did show that Laclede is recovering more in depreciation for net salvage than it is currently spending. Ratepayers pay $2.3 million more in depreciation annually under the accrual method than under Staff's proposed expense method.
>
> Laclede explained this result, however, with evidence showing a consistent and significant upward trend over time in both the installation cost of the plant used by Laclede to provide utility service, as well as in the cost to remove such plant from service. In fact, just maintaining the net salvage percentage at its historical rate would result in a higher level of net salvage costs than that currently being realized by the Company, since it applies to an asset base that has grown and continues to grow over time. For example, the evidence shows that in 1950 Laclede's total plant in service was only 6 percent of what it is today.[13]

The MPSC also addressed intergenerational equity, stating:

> Since it is clear from the evidence in this case that the accrual method comes closer to matching the costs to the benefits derived, the Commission finds that intergenerational equity will be promoted by the continued use of the accrual method.[14]

The MPSC also noted the issue of cash flow:

> The Commission also finds that Staff's method significantly decreases the cash flows available to utilities to meet their infrastructure and other public service obligations. This, in turn, has a negative financial impact on both the utility and its customers by

[12] *Id.* at 8-9. (Emphasis added).
[13] *Id.* at 9-10.
[14] *Id.* at 11-12.

> requiring that such obligations be met with more expensive sources of external financings and by driving up the cost generally of obtaining money in the capital markets. The Commission finds that Staff has not shown that the adoption of its method would justify these increased costs for utility consumers.[15]

Q. HAS ILLINOIS RULED IN FAVOR OF THE TRADITIONAL METHOD?

A. Yes. One example is a case for Ameren's Illinois subsidiaries. The Illinois Commission rejected a method for net salvage that was similar to what Mr. Kollen has proposed in the instant case. The Illinois Commission stated:

> The Commission does not concur with IIEC and the Commercial Group's proposal to depart from the Commission's current treatment of net salvage costs; specifically, using the traditional, accrual method of accounting for net salvage. Although there are some regulatory commissions that have moved away from the methods prescribed for depreciation, this Commission is not inclined to do so as the evidence does not show it is necessary. It has been appropriate to use the traditional method by allocating the cost to each year of the assets' service life rather than when the actual salvage-related costs are incurred. This method of depreciation allocates in a systematic and rational manner the service value of depreciable property over the service life of the property. IIEC's complaint that customers today will pay the same number of dollars as future customers represents a misunderstanding or misrepresentation of the purpose of systematic recovery of depreciation expense, which provides for rate recovery of long-lived assets over their expected useful life. In contrast, the net salvage approach advocated by IIEC and the Commercial Group would improperly push costs into the future that are more appropriately borne by current ratepayers. The Commission understands why such an approach may appear attractive in the short-run, but in the long-term it provides no benefit to ratepayers in aggregate. Further, contrary to the Commercial Group's assertion, the Commission concludes that AIU's reliance on some net salvage estimates from other electric utilities does not result in over-projecting net salvage expense relative to AIU's current net salvage

[15] *Id.* at 14.

> expense. In conclusion, the accrual method for calculating net salvage is consistent with the Commission accounting practices for regulated utilities, has been accepted, deemed appropriate for years, and the Commission remains convinced that it is appropriate in this case.[16]

Q. HAS CALIFORNIA REJECTED PROPOSALS SIMILAR TO THOSE OF MR. KOLLEN?

A. Yes. Proposals similar to those of Mr. Kollen have been proposed and rejected in multiple cases in California.

Q. PLEASE CONTINUE.

A. Various alternative methods for net salvage have been proposed in a number of cases in California. In each case, the non-traditional approaches were rejected.

One such proposal was in Pacific Gas & Electric's (PG&E) 2007 General Rate Case. The Utility Reform Network (TURN) proposed an approach that was very similar to what Mr. Kollen has proposed in the instant case. As the CPUC explained:

> For the previous reasons, TURN recommends that the Commission eliminate inflation from the determination of removal costs. TURN proposes that <u>removal costs for this GRC cycle be based on a rolling three-year or five-year average of PG&E's recorded removal costs</u>. TURN calls this alternative the "normalized net salvage approach." PG&E's revenue requirement for removal costs in 2007 would be \$88 million based on a three-year average of historical removal costs or \$63 million based on a five-year average.[17]

TURN's proposal in that proceeding to use a 3- or 5-year average of recorded removal costs is based on the same premise as Mr. Kollen's of recovering net salvage

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[16] *See* pages 138 and 139 of the Illinois Commerce Commissions order, dated September 24, 2008, in Docket Nos. 07-0585, 07-0586, 07-0587, 07-0588, 07-0589 and 07-0590.
[17] *See* California D.07-03-044 in A.05-12-002, pp. 226 and 227. (Emphasis added)

concurrent with or after retirement. The CPUC rejected TURN's proposal in PG&E's 2007 GRC. The CPUC explained as follows:

> The issue before us is whether to adopt TURN's proposed "normalized net salvage allowance approach" for setting rates to recover asset removal costs. Under TURN's approach there will be no recovery of removal costs until after assets have retired and the associated removal costs have been incurred. TURN's method is, in effect, a form of cash-basis accounting.
>
> TURN's proposal is a marked departure from the current accrual accounting for removal costs. The purpose of using accrual accounting is to allocate to current ratepayers their pro rata share of the costs that will eventually be incurred to remove those assets that are currently being used to provide utility service. This treatment is in harmony with GAAP, the USOA, and longstanding Commission practice under SP U-4.
>
> Accrual accounting for removal costs is fair to ratepayers because it ensures that ratepayers pay for the removal costs of those assets that serve them, and pay no removal costs for assets that do not serve them. On the other hand, TURN's proposal would require ratepayers to pay for removal costs incurred in prior years for assets that are no longer in service. As a matter of equity, we believe that ratepayers should pay only for those assets that currently serve them. TURN's proposal fails this test.[18]

Q. WERE SIMILAR PROPOSALS REGARDING NET SALVAGE PROPOSED BY TURN AND REJECTED BY THE CPUC FOR OTHER CALIFORNIA UTILITIES?

A. Yes. The language from the original order in the most recent case that addressed the net salvage methodology in California, CPUC Docket No. A.06-12-009, summarizes CPUC policy and explains that alternative net salvage methodologies, including a

[18] *See* California D.07-03-044 in A.05-12-002, pp. 226 and 227.

normalized expense approach, were rejected repeatedly in California. The following language is from this case for Sempra Energy in which TURN had challenged the traditional method. In the original Decision 08-07-046, issued August 1, 2008, the CPUC stated on page 23 (emphasis added):

> The alternative methodology proposed by TURN <u>was not adopted in the most recent Pacific Gas & Electric Company (PG&E) and Southern California Edison Company (SCE) GRCs</u>. We would therefore have denied with prejudice the recommendations of DRA, TURN, and UCAN on depreciation and net salvage in a litigated decision. The purpose of this discussion of our likely denial is to avoid an unnecessary repetition in subsequent proceedings. Any party that raises these issues again should have new analysis and new arguments which may persuade us, unlike the arguments raised here or in other recent rate proceedings.

I present the discussion from Docket No. A.06-12-009 because the CPUC makes clear that it had rejected a normalized expense method multiple times.

Q. A PREMISE OF MR. KOLLEN'S APPROACH IS THAT NET SALVAGE ACCRUALS SHOULD BE BASED ON THE LEVEL OF NET SALVAGE EXPENSE RECORDED IN RECENT YEARS. HAS THE CPUC ADDRESSED THE RELATIONSHIP OF NET SALVAGE ACCRUALS TO NET SALVAGE EXPENSE?

A. Yes. It is important to note that other commissions have recognized that these costs should not be the same (*i.e.*, that net salvage accruals will normally be higher than net salvage expense). In California, the CPUC stated in SCE's 2012 GRC Decision D.12-11-051 (emphasis added):

> We are also not persuaded to retain existing rates just because SCE currently <u>accrues negative net salvage at a level higher than annual</u>

> recorded COR. Even if SCE will have sufficient funds to cover removal or net salvage costs in the foreseeable future, it leaves the question of long-term intergenerational equity versus short-term rate tolerance.

Q. DOES FERC ACCEPT THE TRADITIONAL METHOD YOU HAVE PROPOSED?

A. Yes. In fact, in an ongoing case before FERC for Pacific Gas and Electric Company, an intervenor proposed to estimate net salvage in a similar manner to what Mr. Kollen proposed in the instant case. FERC Trial Staff strongly opposed such an approach, and argued that it was not consistent with the USOA.[19]

iii. Authoritative Depreciation Texts Support That Net Salvage Should Be Included in Depreciation

Q. DO AUTHORITATIVE TEXTS ON DEPRECIATION ADDRESS THE ISSUE OF WHETHER NET SALVAGE SHOULD BE ACCRUED DURING THE LIFE OF THE RELATED PLANT?

A. Yes, they do.

Q. WHAT DO THESE TEXTS PROVIDE?

A. Two widely cited, preeminent depreciation texts are the NARUC Public Utility Depreciation Practices (the NARUC Manual) and Depreciation Systems by Wolf and Fitch (Wolf and Fitch). Each explains that net salvage should be accrued over the life of the related property and should be estimated using the traditional method.

[19] *See* Exhibit S-0001 in FERC Docket No. ER16-2320-000.

Q. DO BOTH OF THESE TEXTS SUPPORT THE TRADITIONAL METHOD THAT YOU HAVE PROPOSED?

A. Yes. Both texts support the traditional method.

Q. PLEASE EXPLAIN.

A. The NARUC Manual states at page 157:

> Historically, most regulatory commissions have required that both gross salvage and cost of removal be reflected in depreciation rates. The theory behind this requirement is that, since most physical plant placed in service will have some residual value at the time of retirement, the original cost recovered through depreciation should be reduced by that amount. Closely associated with this reasoning is the accounting principle that revenues be matched with costs and the regulatory principle that utility customers who benefit from the consumption of plant pay for the cost of that plant, no more, no less. The application of the latter principle also requires that the estimated cost of removal of plant be recovered over its life.

The 1994 edition of Depreciation Systems states at page 7:

> The matching principle specifies that all costs incurred to produce a service should be matched against the revenue produced. Estimated future costs of retiring of an asset currently in service must be accrued and allocated as part of the current expenses.

Thus, both of these texts use mandatory language when describing the traditional approach of accruing "retirement" or "removal" costs over the life of the plant. Further, both also support the method of estimating net salvage I have used.

C. RATEMAKING IMPACTS OF THE ATTORNEY GENERAL'S PROPOSAL

Q. CAN YOU EXPLAIN THE IMPACT OF THE NET SALVAGE METHODS ON CUSTOMER RATES?

A. Yes. Not only will the AG's proposal result in intergenerational inequity, but over time, the AG's proposal is actually more expensive to customers on a total cost of service basis.

Q. PLEASE EXPLAIN THE CONCEPT OF "INTERGENERATIONAL EQUITY."

A. Intergenerational equity is a ratemaking principle in which customers receiving the benefit from the use of an asset (*e.g.*, from electric utility property used to provide electric service) are the same customers who pay for the cost of that asset – no more, no less. Including net salvage in depreciation results in intergenerational equity, as the net salvage costs are part of the cost of an asset and should be recovered over its service life.

Q. DOES MR. KOLLEN'S NET SALVAGE PROPOSALS RESULT IN INTERGENERATIONAL EQUITY?

A. No. Mr. Kollen proposes to recover net salvage costs after the Company's assets are retired. His proposal will, therefore, result in intergenerational inequity because future customers will have to pay the costs of assets that only provided service to previous generations of customers.

Q. IN ADDITION TO THE INTERGENERATIONAL INEQUITY CAUSED BY MR. KOLLEN'S PROPOSAL, IS THERE A LONG-TERM IMPACT ON CUSTOMER RATES THAT WILL RESULT FROM MR. KOLLEN'S PROPOSAL?

A. Yes.

Q. PLEASE EXPLAIN THE IMPACT THAT A DEPRECIATION METHOD HAS ON CUSTOMER RATES, OTHER THAN THE DIRECT IMPACT OF DEPRECIATION EXPENSE.

A. Any method of depreciation has an impact on rate base over the lives of the plant assets as rate base includes original plant cost less accumulated depreciation. By deferring costs to the future, over time the AG's method results in a lower level of accumulated depreciation and a higher rate base than would occur under the traditional method. A higher rate base would mean that customers would have to pay a higher return on rate base. Over time, the rate base impact typically exceeds any reduction to depreciation expense. As a result, while the AG's method may produce a short-term reduction in customer rates, it will result in higher total costs to customers over the lives of the plant assets.

Q. DOES THE RATE BASE IMPACT OF THE AG'S PROPOSAL RESULT IN INTERGENERATIONAL INEQUITY?

A. Yes. The rate base impact compounds the intergenerational inequity inherent in AG's proposal. Not only will future customers pay the costs of retired assets for which they receive no benefits, but they will also have to pay a return on a higher rate base due to the fact that previous generations did not pay the full cost of their service.

D. DECOMMISSIONING COSTS FOR POWER PLANTS

Q. IN SECTION II.A YOU EXPLAINED THAT NET SALVAGE MUST BE BASED ON THE FUTURE COSTS EXPECTED TO BE INCURRED, NOT ON TODAY'S COSTS. DOES THE SAME APPLY FOR DECOMMISSIONING OF POWER PLANTS?

A. Yes. Because net salvage must be based on future costs, decommissioning costs for net salvage must also be estimates of the future cost at the time of decommissioning. For this reason, if decommissioning estimates are developed using the cost to decommission a plant today, then these costs must be escalated to the time period in which they are expected to be incurred.

Q. WHAT DOES THE AG PROPOSE WITH REGARD TO THE DECOMMISSIONING COSTS?

A. The AG proposes to eliminate all decommissioning. Mr. Jeffrey Kopp addresses the issues related to decommissioning costs in his direct testimony. Further, as I have explained in Section II.A, because net salvage must be included in depreciation over the lives of the Company's assets, decommissioning for power plants must also be included in depreciation. Thus, my remaining testimony on net salvage will focus on the issue of escalation raised by Mr. Kollen.[20]

Q. FOR THE COMPANY'S CURRENTLY APPROVED DEPRECIATION RATES, WERE THE DECOMMISSIONING COSTS ESCALATED TO THE DATE OF RETIREMENT?

A. Yes. Although, a different escalation factor was settled upon, the same general process I have used in the instant case is currently approved. The AG's proposal is not consistent with the approach used for the Company's currently approved depreciation rates. Further, as noted in Section II.B.ii, the Indiana Commission affirmed the same approach for an affiliate of the Company.

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[20] Mr. Kollen has proposed that, if his primary proposal to remove all decommissioning from depreciation is rejected, then the Commission should instead remove the escalation component from my proposed depreciation rates.

Q. WILL THE AG'S PROPOSAL PROPERLY ALLOCATE THE COMPANY'S COSTS OVER THE SERVICE LIVES OF THEIR GENERATING FACILITIES?

A. No. The decommissioning study prepared by Mr. Kopp used costs at today's price level. However, many of the Company's plants will not be retired for many years. The net salvage costs need to be escalated so that the correct amounts are allocated over the lives of the plants. Mr. Kollen's proposal to remove escalation from the decommissioning costs is insufficient to recover the Company's costs.

Q. PLEASE PROVIDE AN EXAMPLE THAT ILLUSTRATES WHY COSTS MUST BE ESCALATED TO THE DATE OF RETIREMENT.

A. Consider the following example. Assume a Company has a power plant that cost $1,000,000 to construct, will be in service for 40 years, and the net salvage is negative 10 percent. The negative 10 percent represents the cost at retirement, and so in year 40 it will cost $100,000 to decommission the plant. Additionally, assume that inflation occurs at a rate of 2.5 percent. Using the straight-line method, the resulting depreciation accrual would be $27,500 and a depreciation rate of 2.75 percent. This is the proper amount needed to recover the full $1,100,000 over the 40-year life of the power plant.

If instead decommissioning costs were not escalated to the date of retirement, the resulting depreciation rate would not recover the plant's original cost plus the cost to decommission it upon retirement. Consider the calculation of depreciation at year 1, when the asset is placed in service. The decommissioning cost of $100,000 stated in year 1 dollars is only $37,243. This is the amount that the other parties recommend should be included in depreciation expense for the Company's power plants, and their methodology would produce only $25,931 in depreciation expense and a depreciation rate of 2.59 percent. Using such a method will not recover the full-service value (the plant's original cost + decommissioning costs) that the company should be allowed to recover through depreciation. Instead, the Company will only recover $1,037,243 through depreciation expense and will recover less than 40 percent of the actual net salvage costs for the plant. This represents $62,757 less than the full-service value of the plant that the Company is entitled to recover.

Q. SHOULD NET SALVAGE BE RECOVERED IN TODAY'S COST (*I.E.* THE COST IN TODAY'S DOLLARS)?

A. No. In order to recover the service value of the Company's assets, net salvage must be determined at the cost that will be incurred in the future. When using the straight-line method of depreciation, these costs are recovered ratably, or in equal amounts each year, over the life of the Company's plant.

Q. IS RECOVERING THE FUTURE COST OF NET SALVAGE CONSISTENT WITH THE FERC USOA?

A. Yes. The FERC USOA which is discussed further in Section III.B.i. of my testimony, specifically defines net salvage as follows:

> 19. Net salvage value means the salvage value of property retired less the cost of removal.

Cost of removal is defined as:

> 10. Cost of removal means the cost of demolishing, dismantling, tearing down or otherwise removing electric plant, including the cost of transportation and handling incidental thereto. It does not include the cost of removal activities associated with asset retirement

> obligations that are capitalized as part of the tangible long-lived assets that give rise to the obligation. (See General Instruction 25).

Finally, cost is defined as (emphasis added):

> 9. Cost means the <u>amount of money actually paid</u> for property or services. When the consideration given is other than cash in a purchase and sale transaction, as distinguished from a transaction involving the issuance of common stock in a merger or a pooling of interest, the value of such consideration shall be determined on a cash basis.

Read together, it should be clear from these definitions that the USOA specifies that cost of removal, which as part of net salvage must be recovered through depreciation expense, is the actual amount that is paid at the time of the transaction. Because net salvage will occur in the future, it is an estimate of the future cost that must be included in depreciation rates.

Q. DO GENERALLY ACCEPTED DEPRECIATION CONCEPTS SUPPORT THAT THE NET SALVAGE IN DEPRECIATION SHOULD BE INCLUDED AT THE COST THAT WILL BE INCURRED?

A. Yes. Including the future cost of net salvage for plant accounts is consistent with established depreciation concepts. Depreciation is a cost allocation concept, in which the full cost of an asset (original cost less net salvage) is allocated on a straight-line basis over the period of time an asset will be in service.

Q. DO ANY AUTHORITATIVE DEPRECIATION TEXTS SUPPORT THAT THE NET SALVAGE AMOUNT SHOULD REPRESENT THE FUTURE COST?

A. Yes. I have already explained NARUC's discussion of this issue in Section II.B.iii. I note that NARUC also states the following:

> [U]nder presently accepted concepts, the amount of depreciation to be accrued over the life of an asset is its original cost less net salvage. Net salvage is difference between the gross salvage that will be realized <u>when the asset is disposed of and the cost of retiring it</u>.[21] (Emphasis added)

Wolf and Fitch is another highly regarded, authoritative depreciation text. The authors are clear that net salvage should be included in depreciation and that it should be recognized as a future cost. Wolf and Fitch explain that:

> The matching principle specifies that all cost incurred to produce a service should be matched against the revenue produced. Estimated future costs of retiring an asset currently in service must be accrued and allocated as part of the current expenses.[22]

III. <u>EQUAL LIFE GROUP PROCEDURE</u>

Q. WHAT IS THE ELG PROCEDURE?

A. Under the ELG procedure, a group of property (*e.g.*, a vintage within a property account) is subdivided into groups having equal service lives. The size of these "equal life groups" is based on the estimated survivor characteristics of the account. Depreciation can then be calculated for each equal life group based on the straight line method; that is, an equal amount of the group's service value is recorded as depreciation expense in each year of service. The total depreciation for an account is the summation of the depreciation calculated for each equal life group. In other words, based on the survivor curve estimate for an account, the ELG procedure

[21] NARUC Manual at 18.
[22] Wolf and Fitch, p. 7.

mathematically estimates the life for each unit in the account, and then depreciates each unit over its expected life. For this reason, the procedure is also known as the "unit summation" procedure. By calculating depreciation for each equal life group, the ELG procedure contrasts with the Average Service Life ("ASL", also referred to as "Average Life Group", or "ALG") procedure, which depreciates every asset within an account over the average life of the account.

Q ARE THE COMPANY'S CURRENT DEPRECIATION RATES BASED ON THE ELG PROCEDURE?

A. Yes.

Q. PLEASE EXPLAIN THE ELG PROCEDURE AND ILLUSTRATE HOW IT DIFFERS FROM ALG PROCEDURE.

A. A simple example employing two units of property of the same vintage in the same property account will show how the ELG procedure more appropriately matches cost recovery through depreciation to consumption or loss in service value than the ASL procedure. For purposes of this example, it is assumed that each unit has an original cost of $1,000. Unit A will be in service for five (5) years and Unit B will be in service for fifteen (15) years. No net salvage will result from the retirement of either unit.

Under the ASL procedure, the average service life for the two units is ten years: (5+15)/2. The annual depreciation rate is 10% (1/10). Thus, for the first five years that both units are in service, the total amount of annual depreciation is $200 ($2,000 x 10%). Therefore, at the end of year five, the total of five annual accruals for the account is $1,000 ($200 x 5). At that time, Unit A is retired, which results in a deduction of $1,000 from accumulated depreciation. (When a unit of property is retired, its original cost is deducted from both the balance of utility plant in service and from accumulated depreciation.)

At the start of year six, Unit B remains in service, and the original cost ($1,000) is offset by the accumulated depreciation of $0. However, at this point, one third of Unit B's service life has, in fact, expired; its accumulated depreciation should, therefore, not be zero.

For the remaining ten years, $100 (10% x $1,000) of annual depreciation expense is charged to accumulated depreciation, for a total of $1,000 of expense over this period. When Unit B is retired, $1,000 is deducted from accumulated depreciation, and both the original cost and accumulated depreciation will equal zero. When Unit B is retired, the Company will have finally recovered the total depreciable cost of both units. However, at the end of year five only one unit remained in service with two-thirds of its life expectancy still to be consumed, but with 100% of the original investment in that unit still to be recovered. As a result, the ALG procedure did a poor job of matching cost recovery to the actual consumption of the service life the asset.

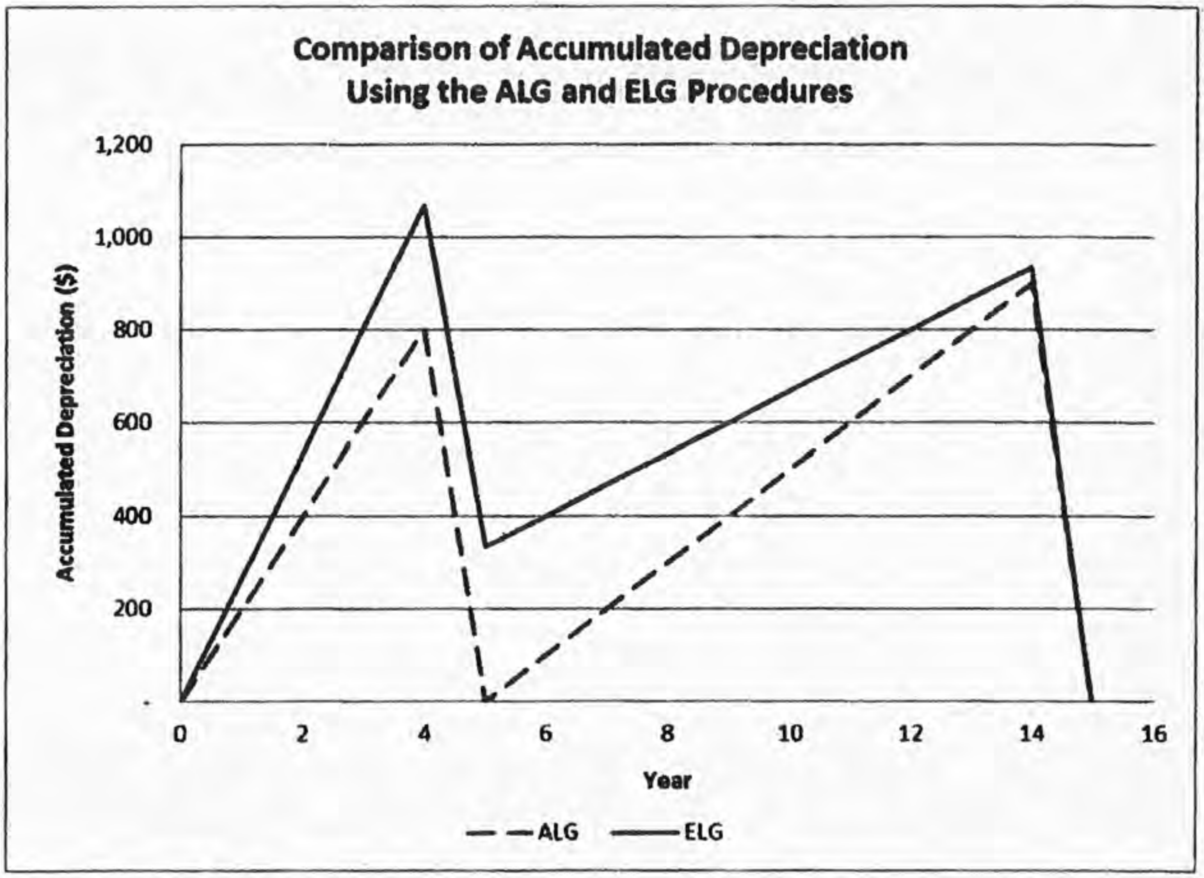
Q. HOW IS DEPRECIATION DETERMINED USING THE ELG PROCEDURE?

A. When depreciation is determined using the ELG procedure, the pattern of cost recovery more accurately matches the actual consumption of property's service value. Using the same two unit example discussed above, the annual depreciation expense under the ELG procedure is calculated by summing the annual expense for each equal life group. In this case, there are two equal life groups – one for Unit A, which has a life of five years, and one for Unit B, which has a life of fifteen years. The annual depreciation rate for Unit A is 20% (1/5) and for Unit B is 6.67% (1/15). Thus, the annual accruals for years one through five will be $200 (20% x $1,000) for the first equal life group (Unit A) summed with $66.67 (6.67% x $1,000) for the second (Unit B), or $266.67. At the end of year 5, when Unit A is retired, the total accruals would be $1,333.33. The retirement of Unit A results in a deduction of $1,000 from accumulated depreciation and, at the start of year 6, the $1,000 original cost of Unit B remains with $333.33 in accumulated depreciation. Thus, with one-third of Unit B's life consumed, accumulated depreciation is exactly one-third of the original cost for this unit.

In the years six through fifteen, the annual depreciation expense is $66.67 or a total of $666.67 over the ten years remaining in the life of Unit B. Thus, when Unit B is retired, the accumulated depreciation goes to $0 ($1,000 is deducted from the total of $1,000 of accruals), and the entire original cost of both units has been recovered.

As the foregoing example shows, the ELG procedure more accurately matches cost recovery for both units with their actual service lives. Figure 1 is a graphic representation of the accumulated depreciation for the same property under both the ELG and ALG procedures. The end of year five provides the best illustration of the difference between the two procedures. Under the ELG procedure, the original cost of Unit A is fully recovered when it is retired at the end of year five; Unit B is one-third through its service life and one-third of its cost has been recovered. For both units, cost recovery matches their service lives. This contrasts with the ALG procedure, in which accumulated depreciation is $0 at the end of year five, despite the fact that one-third of the service life of the only unit remaining in service has been expended.

Figure 1



The area between the two lines on the graph bounded by years five and fifteen represents the additional annual depreciation that would be paid by customers in those years to catch-up for the cost of Unit A that was not recovered when it was providing service. These kinds of inaccuracies can introduce inter-generational inequities, as later generations of customers pay for the recovery of the original cost of plant that was not recovered from customers that received 100% of the service value of that property.

In contrast to the ALG procedure, the ELG procedure assures that cost recovery through annual accruals accurately track the actual service lives for both units of property in my example, which means that cost recovery is properly obtained from the customer who actually receive the service each unit provides.

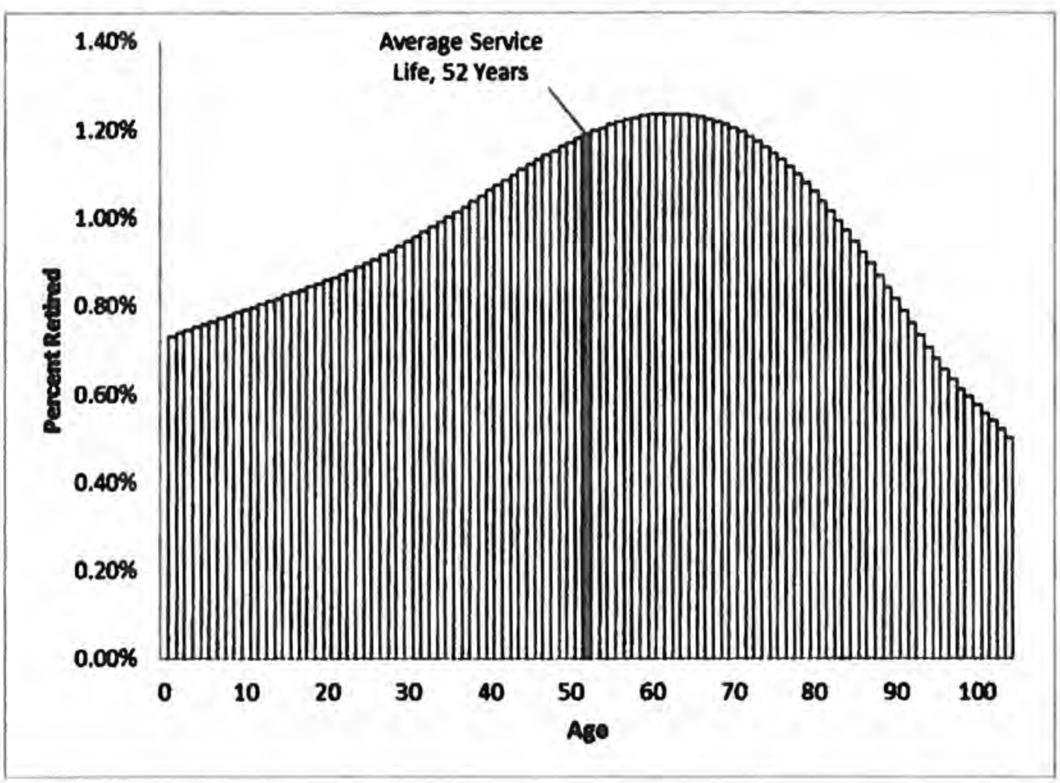
Q. DO THE SAME PRINCIPLES ILLUSTRATED BY THE TWO-UNIT EXAMPLES DISCUSSED ABOVE ALSO APPLY TO LARGER PROPERTY GROUPS THAT CONTAIN MANY MORE UNITS OF PROPERTY?

A. Yes. The same principles apply when the ELG procedure is applied to a large group of property with many units, as is typical of utility property. The survivor curve estimated for each property account can be used to divide an account into equal life groups. The survivor curve allows for the calculation of the percentage of the property account that is in each equal life group, which allows for the calculation of ELG annual depreciation accruals for the entire property group. Under the ALG procedure, the depreciation expense for all property in the account is calculated based on the average service life for the entire group.

The ELG procedure recognizes the reality of "dispersion." Specifically, it recognizes that in actual utility operations only a very small percentage of the dollars of plant investment in an account will actually be retired at the average service life determined for account. Figure 2, below, is a chart of the frequency curve for the 52-R0.5 survivor curve, which I have proposed for Account 364, Poles, Towers and Fixtures, and which no party in this case has challenged. The frequency curve shows the percentage of property in this account that will be retired at each age, based on the estimated survivor curve. This percentage is also the size of each equal life group.

The shaded bar in Figure 2 represents the percentage of property that will have a life of 52 years. In other words, it represents the percentage of property that is expected to be in service a period that corresponds exactly to the average service life for the account. As the chart shows, about 1.2% of the assets will be in service for 52 years; conversely, about 98.8% will have service lives that differ from 52 years. Some poles will be damaged or have to be relocated and, therefore, will be retired much earlier than the average, while others will be in service much longer than the average. Most will fall somewhere between these "tails" of the curve.

Figure 2: Percent Retired by Age Based on 52-R0.5 Survivor Curve



The ELG procedure recognizes dispersion, and allocates costs for each equal life group over the expected life for that group. As a result, the ELG procedure allocates cost in a manner that approximates the result of each asset being depreciated over its actual life. Conversely, the ALG procedure depreciates every unit of property within an account over the same life, that is, the average life of the entire account. As Figure 2 shows, this average life will be incorrect the majority of the time – in this example, the average life will be the wrong life for about 98.8% of the assets.

Thus, just as in the case of the two-unit examples discussed above, the ELG procedure better matches capital recovery with the actual lives that are forecast by the estimated survivor curve.

Q. IS THE ELG PROCEDURE ALSO SUPPORTED BY OTHER DEPRECIATION AUTHORITIES?

A. Yes. ELG is discussed and supported in authoritative depreciation texts and academic literature. One such authority – and a very significant one – is Robley Winfrey, who, as a professor at Iowa State University, developed the Iowa survivor curves that are universally used in estimating service lives based on historical retirement data is generally regarded as the father of utility depreciation practices, referred to the ELG procedure as "the only mathematically correct procedure."[23]

[23] Robley Winfrey, Depreciation of Group Properties, Bulletin 155 (Ames, IA: Iowa State University Press, 1942, reprinted 1969); p. 71

Q. WHAT ARE MR. KOLLEN'S ARGUMENTS AGAINST THE USE OF THE ELG PROCEDURE?

A. Mr. Kollen does not take the merits of ELG head-on. Instead, he just makes the statement that the ELG procedure produces higher depreciation rates and that should be rejected. However, he does not provide justification that ELG is not appropriate, and acknowledged in discovery that both ALG and ELG are straight line and both recover the same amount of expense over the life of the asset.[24]

Q. WHAT DO YOU CONCLUDE REGARDING THE ELG PROCEDURE?

A. The use of the ELG procedure has been utilized for many years in some jurisdictions including Kentucky. Mr. Kollen does not address the ELG procedure other than to disagree with the level of depreciation.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

[24] *See* the Attorney General's response to Duke Energy Kentucky's Data Request No. 86.

VERIFICATION

COMMONWEALTH OF PENNSYLVANIA)
) SS:
COUNTY OF CUMBERLAND)

The undersigned, John J. Spanos, Senior Vice President, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing rebuttal testimony and that it is true and correct to the best of his knowledge, information and belief.

John J. Spanos

John J. Spanos Affiant

Subscribed and sworn to before me by John J. Spanos on this 2nd day of February, 2018.

NOTARY PUBLIC

My Commission Expires: February 20, 2019

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
Cheryl Ann Rutter, Notary Public
East Pennsboro Twp., Cumberland County
My Commission Expires Feb. 20, 2019
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

VERIFICATION

COMMONWEALTH OF PENNSYLVANIA)
) SS:
COUNTY OF CUMBERLAND)

The undersigned, John J. Spanos, President, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing rebuttal testimony and that it is true and correct to the best of his knowledge, information and belief.

John J. Spanos
John J. Spanos Affiant

Subscribed and sworn to before me by John J. Spanos on this 13th day of January, 2020.

NOTARY PUBLIC

My Commission Expires: February 20, 2023

Commonwealth of Pennsylvania - Notary Seal
Cheryl Ann Rutter, Notary Public
Cumberland County
My commission expires February 20, 2023
Commission number 1143028
Member, Pennsylvania Association of Notaries

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2019-00271

DIRECT TESTIMONY OF

JOHN D. SWEZ

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

January 31, 2020

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John D. Swez and my business address is 526 S. Church Street, Charlotte, North Carolina 28202.

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

A. I am employed as Managing Director, Trading and Dispatch, by Duke Energy Carolinas, LLC, a utility affiliate of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or Company).

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

A. I received a Bachelor of Science degree in Mechanical Engineering from Purdue University in 1992. I received a Master's of Business Administration degree from the University of Indianapolis in 1995. I joined PSI Energy, Inc. in 1992 and have held various engineering positions with the Company or its affiliates in the generation dispatch or power trading departments. In 2003, I assumed the position of Manager, Real-Time Operations. Though my title has changed on several occasions, I assumed my current role on November 1, 2019.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS MANAGING DIRECTOR, TRADING AND DISPATCH.

A. As Managing Director, Trading and Dispatch of Duke Energy, I am responsible for Gas, Oil, and Power Trading and Generation Dispatch on behalf of the Duke Energy's regulated utilities in the Carolinas, Florida, Indiana, Ohio, and Kentucky. I am responsible for Duke Energy Kentucky's generation dispatch, unit commitment, 24-hour real-time operations, and plant communications related to short-term generating maintenance planning. I lead the teams responsible for managing the Company's capacity position with respect to meeting its Fixed Resource Requirement (FRR) obligation as a member of PJM Interconnection, L.L.C. (PJM), for the submission of the Company's supply offers and demand bids in PJM's day-ahead and real-time electric energy (collectively Energy Markets) and ancillary services markets (ASM), as well as those managing the Company's short-term supply position to ensure that the Company has adequate economic resources committed to serve its retail customers' electricity needs. In that respect, my teams are also responsible for any financial hedging done to mitigate exposure to short-term energy prices and congestion risks.

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

A. Yes, I have testified before the Kentucky Public Service Commission (Commission) on several occasions.

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

A. The purpose of my testimony is to adopt the testimony of Duke Energy Kentucky's witness John Verderame that was filed in September 2019 in this proceeding. Mr. Verderame now has different responsibilities within the Company. I have read Mr. Verderame's testimony and responses to data requests. Upon review, I noticed a small error in his testimony.

Q. PLEASE DESCRIBE THE CORRECTION NEEDED TO MR. VERDERAME'S TESTIMONY.

On page 9, lines 11 and 13, Mr. Verderame inadvertently switched the terms UCAP and ICAP. The sentence should have said, "For IRP purposes, this is done on an ICAP basis versus the PJM planning reserve margin which is calculated on an UCAP basis." Otherwise, I agree with Mr. Verderame's testimony and responses.

Q. DO YOU HEREBY ADOPT MR. VERDERAME'S TESTIMONY AND DATA REQUEST RESPONSES FOR PURPOSES OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Yes.

II. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

VERIFICATION

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

The undersigned, John D. Swez, Managing Director of Trading & Dispatch, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing rebuttal testimony, and it is true and correct to the best of his knowledge, information and belief.

John D. Swez

John D. Swez, Affiant

Subscribed and sworn to before me by John D. Swez on this 23 day of January, 2020.

Mary B Vicknair

NOTARY PUBLIC

My Commission Expires:

MARY B VICKNAIR
NOTARY PUBLIC
Davie County
North Carolina
My Commission Expires Sept. 21, 2022

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)	Case No. 2019-00271

REBUTTAL TESTIMONY OF

WILLIAM DON WATHEN JR.

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

January 31, 2020

TABLE OF CONTENTS

PAGE

ATTACHMENTS:

Attachment WDW-Rebuttal-1	Calculations
Attachment WDW-Rebuttal-2	LK-19 Update

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William Don Wathen Jr., and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

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

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

Q. ARE YOU THE SAME WILLIAM DON WATHEN JR. THAT SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to a recommendation made by the Attorney General witnesses Lane Kollen. Specifically, I will address Mr. Kollen's recommendations related to transmission costs.

II. TRANSMISSION EXPENSE

Q. PLEASE DESCRIBE MR. KOLLEN'S RECOMMENDATION WITH REGARD TO THE REFUNDS THE COMPANY RECEIVED FOR PJM CHARGES FOR REGIONAL TRANSMISSION EXPANSION PLANNING COSTS.

A. Mr. Kollen argues that customers should receive refunds for costs they never had to pay. Duke Energy Kentucky has been billed for Regional Transmission Expansion Planning (RTEP) costs since it became a member of PJM on January 1, 2012. Although shareholders exclusively bore the cost for RTEP charges from PJM from January 1, 2012, through April 30, 2018, Mr. Kollen believes that customers should get the full value of the refunds Duke Energy Kentucky received for being overbilled during that period. Mr. Kollen recommends a reduction in the Company's proposed revenue requirement of $1.603 million to reflect a five-year amortization of these refunds in the Company's electric base rates.

Q. WHAT IS THE BASIS FOR THE REFUNDS OF RTEP CHARGES TO DUKE ENERGY KENTUCKY?

A. Well before Duke Energy Kentucky even became a member of PJM[1], the Federal Energy Regulatory Commission (FERC) was considering the allocation methodology used by PJM to allocate the costs of certain expansion projects. Ultimately, the FERC approved a settlement on May 31, 2018, modifying the allocation methodology retroactively. The FERC's Order on Contested Settlement, in Docket No. EL05-121-009, issued on May 31, 2018, settled the case and resulted in refunds for a number of PJM participants, including Duke Energy Kentucky. Because Duke Energy Kentucky was not a PJM member prior to January 1, 2012, its share of the refunds was only for the charges it incurred from January 1, 2012, until the revised allocation methodology became effective after June 2018.

[1] Duke Energy Kentucky transitioned from the Midcontinent Independent System Operator, Inc., to PJM on January 1, 2012, as approved by the Commission on January 25, 2011, in Case No. 2010-00203.

Q. WHAT IS MR. KOLLEN'S RATIONALE FOR HIS RECOMMENDATION?

A. His argument rests on his assessment that Duke Energy Kentucky has recovered more revenue in its base rates for transmission operating and maintenance (O&M) expenses from 2012 through 2018 than the transmission O&M expenses it actually incurred for the same period; therefore, in Mr. Kollen's opinion, any refund of any other expense, whether explicitly included in rates or not, should be flowed back to customers.

Q. HOW DO YOU RESPOND TO MR. KOLLEN'S TESTIMONY ON THIS POINT?

A. Mr. Kollen's logic suggests that the Commission compare the sum of total base revenue related to transmission O&M collected for some, but not all of the years, between rate cases to the overall transmission O&M incurred for those same years. And, if the total revenue exceeds the total costs, then customers are due a refund. From January 1, 2007, through April 30, 2018, the Company's base rates for electric service, including a component for transmission O&M, were established pursuant to Commission's order approving the Company's application in Case No. 2006-00172. So, a fair comparison of what the Company has been collecting in revenue for transmission expense versus what it incurred in expense would cover the entire period, not just a random interim period in between.

Although I disagree with the premise of Mr. Kollen's argument, if he was being fair, his argument would suggest that if the Company's revenue related to transmission O&M expense over that period was less than its actual transmission

O&M expense, then the Company should be able to recover the difference. Using Mr. Kollen's logic, if we assume that Duke Energy Kentucky recovered the amount included in base rates ($16.940 million)[2] from the 2006 rate case, from 2007 through April 30, 2018, and then at the level included in the 2017 rate case ($21.240 million on an annualized basis)[3] for the period May 1, 2018[4], through December 31, 2018, and compare that to the total transmission O&M expense (Accounts 560-576)[5] charged to Duke Energy Kentucky over that period, it is clear that Duke Energy Kentucky has significantly *under-recovered* its transmission O&M expense over that period. The total transmission costs charged to Duke Energy Kentucky over that period is $243.5 million[6] compared to $206.1 million[7] in revenue it has received from retail customers. See Attachment WDW-Rebuttal-1 for the detailed calculations.

Mr. Kollen attempts to skew the analysis by just comparing revenue versus costs for the period from 2012 through 2018. Although Duke Energy Kentucky was not a member of PJM until 2012, it was a member of Midcontinent Independent System Operator (MISO) up until 2012 and incurred transmission expansion planning costs billed from MISO, that were not included in the base rates established in the 2006 base rate case.

He argues that from January 1, 2012, through December 31, 2018, the Company recovered seven years' worth of revenue at the amount included in base

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[2] Kollen's direct, p. 36, line 4.

[3] Source: Attachment WDW-Rebuttal-1

[4] Base rates were updated in May 2018 as a result of the Commission's order in Case No. 2017-00321.

[5] Per the Uniform System of Accounts, Accounts 560-576 are transmission O&M accounts.

[6] Source: Attachment WDW-Rebuttal-1

[7] Source: Attachment WDW-Rebuttal-1

rates from the 2006 rate case, or $118.580 million (7 years * $16.940 million per year). He then compares that figure to what he apparently believes is the total transmission O&M expense for the same period, $111.070 million, excluding the impact of the refund that was recorded in 2018. Mr. Kollen either willfully or inadvertently failed to include all of the Company's transmission O&M expenses incurred over that period. In his Exhibit LK-19, Mr. Kollen provided copies of selected pages (page 321) of Duke Energy Kentucky's FERC Form 1 Annual Report showing the annual cost recorded in transmission accounts 560-573. Mr. Kollen completely ignored other components of the Company's transmission O&M expenses that are shown on page 322. Per the Uniform System of Accounts, electric utilities record charges billed from regional transmission organizations in Accounts 575 and 576. These accounts are also considered transmission O&M expense that are recoverable from retail ratepayers.

I have updated Mr. Kollen's Exhibit LK-19, on Attachment WDW-Rebuttal-2, to include FERC Form 1 data for these accounts for years 2007 through 2018. Correcting Mr. Kollen's calculation to reflect all total transmission O&M expenses incurred by Duke Energy Kentucky for 2012 through 2018, the total transmission O&M expenses of $122.617 million incurred by Duke Energy Kentucky over the period 2012 through 2018. Comparing that figure to Mr. Kollen's calculation of $118.58 million in revenue collected for transmission O&M expense over that same period, shows that transmission O&M expenses for the period 2012 through 2018 exceeded revenue by over $4 million. By Mr. Kollen's reasoning, customers owe Duke Energy Kentucky the $4 million difference. Of course, the Company is not making such a request, but the example highlights the absurdity of Mr. Kollen's proposal.

I should also point out that Mr. Kollen's calculation of the total revenue for the period is also incorrect in that it fails to recognize that the Company's base rates changed on May 1, 2018; so, he should have modified his 2018 revenue estimate to reflect this change. I corrected this in Attachment WDW-Rebuttal-2 but the result is essentially the same...Duke Energy Kentucky's total transmission expenses for 2012 through 2018 are greater than the total revenue it received for transmission via base rates. If all of the years between the two rate cases are considered, 2007 through 2018, the under-recovery of transmission expenses would be significantly greater, partly because the transmission expansion planning costs (*i.e.*, MTEP charges) from MISO have never been recovered in rates.

Q. MR. KOLLEN REFERENCES A FILING RELATED TO KENTUCKY POWER AS SUPPORT FOR HIS PROPOSAL. IS THE KENTUCKY POWER CASE ANALOGOUS TO THE ISSUE FOR DUKE ENERGY KENTUCKY?

A. No. The Kentucky Power Company (Kentucky Power) filed a rate case in 2009, Case No. 2009-00459, using a historical test year of the twelve months ending September 30, 2009. In that case, Kentucky Power sought to implement a new rider, Transmission Adjustment Tariff (TTA), to flow through to customers the difference between its transmission costs included in base rates and what it was actually billed for certain transmission services provided by PJM, including network integrated transmission service and regional transmission expansion projects. Mr. Kollen was a witness in that case on behalf of the Kentucky Industrial Users Coalition (KIUC). A colleague of Mr. Kollen's at Kennedy and Associates, Stephen Baron, filed testimony on behalf of KIUC opposing Kentucky Power's proposed TTA. Ultimately, Kentucky Power withdrew its requested TTA but it is clear from the filings in that case that the revenue requirement approved included recovery of a base amount of RTEP expenses.

Direct and rebuttal testimony filed in that case filed by Kentucky Power's witness, Dennis W. Bethel, in Case No. 2009-00459, indicates that Kentucky Power began recovering RTEP charges from customers around the same time that RTEP charges were first imposed on it by PJM. Understandably, Kentucky Power is required to refund all of the refunds it received from PJM related to FERC Order 494 because it *has been* recovering RTEP charges in rates from the time it began incurring those costs. It is only fair to return to customers a refund for costs that customers bore.

On the other hand, Duke Energy Kentucky's retail ratepayers did not pay for any RTEP charges until such charges were included in base rates beginning on May 1, 2018. The Company conceded in discovery that it should refund the amount of RTEP refunds attributable to May and June of 2018 as customers were paying RTEP charges as part of new base rates; however, only the Company's shareholders paid transmission expansion planning costs (billed from PJM or from MISO) up until May 1, 2018. It would be very unfair to require the shareholders to refund dollars for charges it was overbilled when none of those charges were ever collected from customers.

As I explained in my Direct Testimony in the Company's last base electric rate case, Case No 2017-00321:

> ... [T]he Company is only seeking recovery of RTEP charges beginning with charges incurred for periods beginning April 1, 2018, *i.e.*, the first day of the forecasted test period in this case. There was no deferral mechanism created for the Company to recover transmission expansion costs for prior years. As a result, customers have not been paying and will not pay for RTEP costs incurred through March 31, 2018 (assuming the Commission approves new rates as part of this case to be effective April 1, 2018). [8]

Moreover, prior to the Commission's Order in Case No. 2017-00321, the Company did not have *any* transmission expansion costs in its base rates. This is because the Company's most recent electric rate case, prior to Case No. 2017-00321, was filed in 2006. At that time, the Company was a member of MISO, but MISO had not yet instituted its own transmission expansion plan costs (MTEP). Accordingly, transmission expansion costs only came into existence during the period between the Company's electric rate cases.

Arguably, Mr. Kollen's attempt to invoke the Kentucky Power resolution of RTEP charges and refunds supports the Company's position as it reflects the matching of costs and revenue. In the Kentucky Power case, the refunds should go to customers because the customers explicitly paid for these costs. For Duke Energy Kentucky the matching principle would support that shareholders, who exclusively bore the costs for most of the relevant period, should receive the

[8] *In the Matter of the Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3)Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief,* Case No. 2017-00321, Direct Testimony of William Don Wathen Jr., p. 22 (September 1, 2017).

benefit of refunds for overbillings during that period.

The Commission should reject Mr. Kollen's unequitable and confiscatory recommendation.

III. CONCLUSION

Q. WHERE ATTACHMENTS WDW-REBUTTAL-1 AND WDW-REBUTTAL-2 PREPARED BY YOU AND UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Duke Energy Kentucky, Inc.
Transmission Expense vs.
Transmission Expense Recovered in Rates

		Transmission Exp. Collected in Rates		Transmission Expenses per FERC Form 1											
Acct	Description	2007 - Apr. 2018	May 2018 - Present	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
560	Supervision & Engineering	$ 59,231	$ 39,904	$ 98,717	$ 55,350	$ 36,352	$ 6,230	$ 6,202	$ 19,822	$ 18,154	$ 2,225	$ 7,699	$ 3,132	$ 2,789	$ 2,518
561	Load Dispatching	1,891,531	4,507,629	1,013,314	899,160	1,403,761	1,060,717	1,374,936	361,424	317,588	528,975	563,803	2,124,807	3,134,302	5,271,851
562	Station Expense	4,064	108,794	69,078	115,821	183,302	116,667	106,518	99,625	119,495	98,548	116,017	107,358	111,250	148,685
563	Overhead Lines	12,180	22,478	14,348	22,451	203,659	81,675	88,323	40,881	44,712	83,162	103,310	16,744	46,121	33,532
565	Transmission of Electricity by Others	12,043,213	13,361,709	17,325,885	16,813,303	15,773,589	17,241,235	27,082,235	11,169,053	8,944,811	11,958,297	14,117,924	15,553,606	12,797,078	13,909,634
566	Miscellaneous Transmission	42,517	331,678	61,450	8,717	23	68	2,628,943	201,817	130,672	286,930	409,751	629,025	481,220	486,517
567	Rents - Interco CG&E	1,933,776	-	1,934,700	1,934,700	1,934,700	1,934,700	1,934,161	701,774		935	618	1,668	-	-
568	Supervision & Engineering	79,147	-	7,912	4,235	-	-	-	-	11	11	-	-	-	-
569	Structures	59,045	258,690	10,459	53,782	291,085	176,679	157,445	170,877	100,444	177,819	285,420	242,127	106,831	164,767
570	Station Equipment	8,340	280,677	79,007	196,460	178,267	562,193	280,257	390,270	304,018	315,030	279,482	329,419	335,680	255,031
571	Overhead Lines	806,712	612,194	158,295	226,912	76,996	295,352	134,549	295,028	225,835	361,344	299,887	409,659	230,761	428,751
572	Underground Lines	-	-	-	2,570	6,190	4,006	9,754	25,860	24,026	29,132	-	-	-	-
573	Misc. Transmission Plant	-	-	4,145	(994)						5	-	-	-	2,108
575	Regional Marketing	-	1,716,657	750,811	794,621	979,808	937,155	908,830	1,339,759	1,580,293	1,598,163	1,707,710	1,731,904	1,870,407	1,689,716
	Total Transmission Expense	$ 16,939,756	$ 21,240,410	$ 21,528,121	$ 21,127,088	$ 21,067,732	$ 22,416,677	$ 34,712,153	$ 14,816,190	$ 11,810,059	$ 15,440,576	$ 17,891,621	$ 21,149,449	$ 19,116,439	$ 22,393,110

	Total	2012-2018												
Recovered in Rates	$ 206,144,174	$ 121,445,394	$ 16,939,756	$ 16,939,756	$ 16,939,756	$ 16,939,756	$ 16,939,756	$ 16,939,756	$ 16,939,756	$ 16,939,756	$ 16,939,756	$ 16,939,756	$ 16,939,756	$ 19,806,858
Transmission Expense	$ 243,469,215	$ 122,617,444	$ 21,528,121	$ 21,127,088	$ 21,067,732	$ 22,416,677	$ 34,712,153	$ 14,816,190	$ 11,810,059	$ 15,440,576	$ 17,891,621	$ 21,149,449	$ 19,116,439	$ 22,393,110
Under-Recovery of Transmission Exp	$ (37,325,041)	$ (1,172,050)												

THIS FILING IS

Item 1: [X] An Initial (Original) Submission OR [ ] Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 2/29/2009)
Form 1-F Approved
OMB No. 1902-0029
(Expires 2/28/2009)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 2/28/2009)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature.

Exact Legal Name of Respondent (Company)	Year/Period of Report
Duke Energy Kentucky, Inc.	End of 2008/Q4

Name of Respondent Duke Energy Kentucky, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	228,130	140,063
63	(547) Fuel	12,363,666	14,313,615
64	(548) Generation Expenses	450,428	542,324
65	(549) Miscellaneous Other Power Generation Expenses	424,596	514,988
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	13,466,820	15,510,990
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	20,697	8,957
70	(552) Maintenance of Structures	130,414	41,865
71	(553) Maintenance of Generating and Electric Plant	2,406,950	1,132,275
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	538,614	35,295
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	3,096,675	1,218,392
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	16,563,495	16,729,382
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	48,741,108	62,077,740
77	(556) System Control and Load Dispatching	114,968	216,412
78	(557) Other Expenses	-3,052,640	729,679
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	45,803,436	63,023,831
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	190,369,177	186,658,771
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	55,350	98,717
84	(561) Load Dispatching		178,470
85	(561.1) Load Dispatch-Reliability	102,646	66,501
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	43,701	9,523
87	(561.3) Load Dispatch-Transmission Service and Scheduling	-257	
88	(561.4) Scheduling, System Control and Dispatch Services	709,796	715,531
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	43,274	43,289
93	(562) Station Expenses	115,821	69,078
94	(563) Overhead Lines Expenses	22,451	14,348
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	16,813,303	17,325,885
97	(566) Miscellaneous Transmission Expenses	8,717	61,450
98	(567) Rents	1,934,700	1,934,700
99	TOTAL Operation (Enter Total of lines 83 thru 98)	19,849,502	20,517,492
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	4,235	7,912
102	(569) Maintenance of Structures	9,736	10,459
103	(569.1) Maintenance of Computer Hardware	2,346	
104	(569.2) Maintenance of Computer Software	41,700	
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	196,460	79,007
108	(571) Maintenance of Overhead Lines	226,912	158,295
109	(572) Maintenance of Underground Lines	2,570	
110	(573) Maintenance of Miscellaneous Transmission Plant	-994	4,145
111	TOTAL Maintenance (Total of lines 101 thru 110)	482,965	259,818
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	20,332,467	20,777,310

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
20090429-8017 FERC PDF (Unofficial) 04/28/2009 Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	794,621	750,811
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	794,621	750,811
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	794,621	750,811
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	116,245	216,780
135	(581) Load Dispatching	436,999	16,680
136	(582) Station Expenses	325,643	185,125
137	(583) Overhead Line Expenses	277,063	353,201
138	(584) Underground Line Expenses	149,853	54,602
139	(585) Street Lighting and Signal System Expenses	6,975	25,886
140	(586) Meter Expenses	288,965	29,512
141	(587) Customer Installations Expenses	713,015	356,856
142	(588) Miscellaneous Expenses	413,634	387,983
143	(589) Rents	494,928	494,928
144	TOTAL Operation (Enter Total of lines 134 thru 143)	3,223,320	2,121,553
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	115,351	201,966
147	(591) Maintenance of Structures	62,996	25,935
148	(592) Maintenance of Station Equipment	298,083	208,730
149	(593) Maintenance of Overhead Lines	4,314,182	3,788,910
150	(594) Maintenance of Underground Lines	311,783	346,369
151	(595) Maintenance of Line Transformers	88,571	105,586
152	(596) Maintenance of Street Lighting and Signal Systems	96,905	56,301
153	(597) Maintenance of Meters	239,063	187,054
154	(598) Maintenance of Miscellaneous Distribution Plant	-29,948	37,311
155	TOTAL Maintenance (Total of lines 146 thru 154)	5,496,986	4,958,162
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	8,720,306	7,079,715
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	14,235	24,798
160	(902) Meter Reading Expenses	986,864	933,492
161	(903) Customer Records and Collection Expenses	3,221,753	3,247,759
162	(904) Uncollectible Accounts	2,564,991	2,675,399
163	(905) Miscellaneous Customer Accounts Expenses	-46,234	75,852
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	6,741,609	6,957,300

THIS FILING IS	
Item 1: [x] An Initial (Original) Submission	OR [ ] Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 12/31/2011)
Form 1-F Approved
OMB No. 1902-0029
(Expires 12/31/2011)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 1/31/2012)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature.

Exact Legal Name of Respondent (Company)	Year/Period of Report
Duke Energy Kentucky, Inc.	End of 2010/Q4

Name of Respondent	This Report Is	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	268,525	437,608
63	(547) Fuel	8,558,296	6,374,743
64	(548) Generation Expenses	445,288	390,230
65	(549) Miscellaneous Other Power Generation Expenses	763,686	642,399
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	10,035,795	7,844,980
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	32,476	48,979
70	(552) Maintenance of Structures	499,798	224,017
71	(553) Maintenance of Generating and Electric Plant	4,625,132	3,252,712
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	135,604	235,341
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	5,293,010	3,761,049
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	15,328,805	11,606,029
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	34,126,610	22,087,441
77	(556) System Control and Load Dispatching		
78	(557) Other Expenses	-3,136,806	9,863,496
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	30,989,804	31,950,937
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	184,407,902	186,852,314
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	6,230	36,352
84	(561) Load Dispatching		
85	(561.1) Load Dispatch-Reliability	80,357	67,685
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	194,813	465,193
87	(561.3) Load Dispatch-Transmission Service and Scheduling	15,860	109,693
88	(561.4) Scheduling, System Control and Dispatch Services	727,013	717,492
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	42,674	43,698
93	(562) Station Expenses	116,667	183,302
94	(563) Overhead Lines Expenses	81,675	203,659
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	17,241,235	15,773,589
97	(566) Miscellaneous Transmission Expenses	68	23
98	(567) Rents	1,934,700	1,934,700
99	TOTAL Operation (Enter Total of lines 83 thru 98)	20,441,292	19,535,386
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures	17,440	10,136
103	(569.1) Maintenance of Computer Hardware	14,882	10,184
104	(569.2) Maintenance of Computer Software	144,297	270,637
105	(569.3) Maintenance of Communication Equipment	60	128
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	562,193	178,267
108	(571) Maintenance of Overhead Lines	295,352	76,996
109	(572) Maintenance of Underground Lines	4,006	6,190
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	1,038,230	552,538
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	21,479,522	20,087,924

Name of Respondent	This Report Is	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	937,155	979,808
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	937,155	979,808
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	937,155	979,808
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering		16
135	(581) Load Dispatching	638,351	692,614
136	(582) Station Expenses	188,606	256,726
137	(583) Overhead Line Expenses	252,740	201,871
138	(584) Underground Line Expenses	374,421	301,112
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	279,853	367,593
141	(587) Customer Installations Expenses	883,118	1,046,769
142	(588) Miscellaneous Expenses	912,956	1,189,254
143	(589) Rents	494,928	494,928
144	TOTAL Operation (Enter Total of lines 134 thru 143)	4,024,973	4,550,883
145	Maintenance		
146	(590) Maintenance Supervision and Engineering		
147	(591) Maintenance of Structures	220,745	38,547
148	(592) Maintenance of Station Equipment	349,791	163,365
149	(593) Maintenance of Overhead Lines	3,598,002	4,588,036
150	(594) Maintenance of Underground Lines	267,438	247,921
151	(595) Maintenance of Line Transformers	-64,114	5,052
152	(596) Maintenance of Street Lighting and Signal Systems	134,879	234,864
153	(597) Maintenance of Meters	235,559	154,408
154	(598) Maintenance of Miscellaneous Distribution Plant	-27,755	43
155	TOTAL Maintenance (Total of lines 146 thru 154)	4,714,545	5,432,236
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	8,739,518	9,983,119
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	805	7,843
160	(902) Meter Reading Expenses	988,901	1,197,835
161	(903) Customer Records and Collection Expenses	5,309,327	3,864,114
162	(904) Uncollectible Accounts	2,760,671	2,309,963
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	9,059,704	7,379,755

THIS FILING IS	
Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)
Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature.

Exact Legal Name of Respondent (Company)	Year/Period of Report
Duke Energy Kentucky, Inc.	End of 2012/Q4

Name of Respondent	This Report Is	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	305,660	343,486
63	(547) Fuel	1,202,379	6,524,424
64	(548) Generation Expenses	294,809	361,102
65	(549) Miscellaneous Other Power Generation Expenses	703,096	864,909
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	2,505,944	8,093,921
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	37,084	26,788
70	(552) Maintenance of Structures	576,342	499,009
71	(553) Maintenance of Generating and Electric Plant	3,146,594	5,349,289
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	177,492	122,360
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	3,937,512	5,997,446
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	6,443,456	14,091,367
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	53,912,270	31,481,422
77	(556) System Control and Load Dispatching		
78	(557) Other Expenses	4,009,798	-4,970,557
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	57,922,068	26,510,865
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	187,042,138	179,861,057
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	19,822	6,202
84			
85	(561.1) Load Dispatch-Reliability	82,314	77,204
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	124,689	353,009
87	(561.3) Load Dispatch-Transmission Service and Scheduling	17,333	15,661
88	(561.4) Scheduling, System Control and Dispatch Services	137,114	882,082
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	-26	46,980
93	(562) Station Expenses	99,625	106,518
94	(563) Overhead Lines Expenses	40,881	88,323
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	11,169,053	27,082,235
97	(566) Miscellaneous Transmission Expenses	201,817	2,628,943
98	(567) Rents	701,774	1,934,161
99	TOTAL Operation (Enter Total of lines 83 thru 98)	12,594,396	33,221,318
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures	9,366	11,375
103	(569.1) Maintenance of Computer Hardware	15,655	16,997
104	(569.2) Maintenance of Computer Software	141,396	124,924
105	(569.3) Maintenance of Communication Equipment	4,460	4,149
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	390,270	280,257
108	(571) Maintenance of Overhead Lines	295,028	134,549
109	(572) Maintenance of Underground Lines	25,860	9,754
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	882,035	582,005
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	13,476,431	33,803,323

Name of Respondent	This Report Is	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	1,339,759	908,830
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	1,339,759	908,830
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	1,339,759	908,830
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering		6,612
135	(581) Load Dispatching	579,396	476,768
136	(582) Station Expenses	178,798	179,599
137	(583) Overhead Line Expenses	330,177	165,064
138	(584) Underground Line Expenses	327,769	401,233
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	401,763	405,197
141	(587) Customer Installations Expenses	1,106,447	1,028,382
142	(588) Miscellaneous Expenses	1,084,699	1,569,929
143	(589) Rents		206,220
144	TOTAL Operation (Enter Total of lines 134 thru 143)	4,009,049	4,439,004
145	Maintenance		
146	(590) Maintenance Supervision and Engineering		
147	(591) Maintenance of Structures	47,727	49,055
148	(592) Maintenance of Station Equipment	299,410	358,112
149	(593) Maintenance of Overhead Lines	5,039,680	4,049,889
150	(594) Maintenance of Underground Lines	252,329	207,162
151	(595) Maintenance of Line Transformers	50,724	-24,075
152	(596) Maintenance of Street Lighting and Signal Systems	222,678	146,457
153	(597) Maintenance of Meters	172,920	193,986
154	(598) Maintenance of Miscellaneous Distribution Plant		
155	TOTAL Maintenance (Total of lines 146 thru 154)	6,085,468	4,980,586
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	10,094,517	9,419,590
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		402
160	(902) Meter Reading Expenses	955,148	967,928
161	(903) Customer Records and Collection Expenses	4,617,171	5,385,435
162	(904) Uncollectible Accounts	1,623,077	2,530,854
163	(905) Miscellaneous Customer Accounts Expenses	30	
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	7,195,426	8,893,619

THIS FILING IS	
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Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2016)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2016)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

Exact Legal Name of Respondent (Company)	Year/Period of Report
Duke Energy Kentucky, Inc.	End of 2014/Q4

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2015	End of 2014/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	338,833	322,726
63	(547) Fuel	3,634,500	918,422
64	(548) Generation Expenses	202,828	246,770
65	(549) Miscellaneous Other Power Generation Expenses	1,173,830	646,794
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	5,349,991	2,134,712
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	49,536	87,668
70	(552) Maintenance of Structures	502,459	714,371
71	(553) Maintenance of Generating and Electric Plant	266,446	276,068
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	182,642	118,299
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	1,001,083	1,196,406
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	6,351,074	3,331,118
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	94,919,008	45,990,717
77	(556) System Control and Load Dispatching	510	
78	(557) Other Expenses	6,755,666	4,971,062
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	101,675,184	50,961,779
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	227,245,343	188,292,296
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,225	18,154
84			
85	(561.1) Load Dispatch-Reliability	86,039	79,077
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	385,000	106,082
87	(561.3) Load Dispatch-Transmission Service and Scheduling	52,420	14,728
88	(561.4) Scheduling, System Control and Dispatch Services		117,701
89	(561.5) Reliability, Planning and Standards Development	5,516	
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	98,548	119,495
94	(563) Overhead Lines Expenses	83,162	44,712
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	11,958,297	8,944,811
97	(566) Miscellaneous Transmission Expenses	286,930	130,672
98	(567) Rents	935	
99	TOTAL Operation (Enter Total of lines 83 thru 98)	12,959,072	9,575,432
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	11	11
102	(569) Maintenance of Structures	7,273	11,359
103	(569.1) Maintenance of Computer Hardware	19,511	16,670
104	(569.2) Maintenance of Computer Software	151,035	71,029
105	(569.3) Maintenance of Communication Equipment		1,386
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	315,030	304,018
108	(571) Maintenance of Overhead Lines	361,344	225,835
109	(572) Maintenance of Underground Lines	29,132	24,026
110	(573) Maintenance of Miscellaneous Transmission Plant	5	
111	TOTAL Maintenance (Total of lines 101 thru 110)	883,341	654,334
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	13,842,413	10,229,766

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2015	End of 2014/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	1,598,163	1,580,293
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	1,598,163	1,580,293
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	1,598,163	1,580,293
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	152,126	16,296
135	(581) Load Dispatching	399,106	596,885
136	(582) Station Expenses	179,532	217,018
137	(583) Overhead Line Expenses	256,911	333,417
138	(584) Underground Line Expenses	343,318	343,439
139	(585) Street Lighting and Signal System Expenses	28	
140	(586) Meter Expenses	365,137	392,431
141	(587) Customer Installations Expenses	1,295,965	1,157,423
142	(588) Miscellaneous Expenses	2,091,716	1,435,151
143	(589) Rents	1,713	
144	TOTAL Operation (Enter Total of lines 134 thru 143)	5,085,552	4,492,060
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,994	
147	(591) Maintenance of Structures	21,461	29,318
148	(592) Maintenance of Station Equipment	407,101	292,006
149	(593) Maintenance of Overhead Lines	4,893,204	4,460,304
150	(594) Maintenance of Underground Lines	455,648	359,010
151	(595) Maintenance of Line Transformers	46,032	63,817
152	(596) Maintenance of Street Lighting and Signal Systems	444,799	396,591
153	(597) Maintenance of Meters	313,584	179,513
154	(598) Maintenance of Miscellaneous Distribution Plant	6	
155	TOTAL Maintenance (Total of lines 146 thru 154)	6,583,829	5,780,559
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	11,669,381	10,272,619
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	132,438	185
160	(902) Meter Reading Expenses	629,704	906,305
161	(903) Customer Records and Collection Expenses	4,689,485	4,260,297
162	(904) Uncollectible Accounts	1,193,055	1,328,084
163	(905) Miscellaneous Customer Accounts Expenses	542	158
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	6,645,224	6,495,029

THIS FILING IS	
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Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
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Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

Exact Legal Name of Respondent (Company)	Year/Period of Report
Duke Energy Kentucky, Inc.	End of 2016/Q4

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/13/2017	End of 2016/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	387,652	381,215
63	(547) Fuel	2,274,241	5,426,433
64	(548) Generation Expenses	272,293	287,728
65	(549) Miscellaneous Other Power Generation Expenses	1,036,079	1,134,516
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	3,970,265	7,229,892
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	43,717	14,590
70	(552) Maintenance of Structures	458,636	348,973
71	(553) Maintenance of Generating and Electric Plant	2,545,942	540,800
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	188,372	177,438
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	3,236,667	1,081,801
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	7,206,932	8,311,693
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	41,650,445	32,566,220
77	(556) System Control and Load Dispatching	1,080	868
78	(557) Other Expenses	13,422,745	5,932,609
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	55,074,270	38,499,697
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	186,570,859	195,643,840
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,132	7,699
84			
85	(561.1) Load Dispatch-Reliability	104,843	101,477
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	490,530	405,611
87	(561.3) Load Dispatch-Transmission Service and Scheduling	68,624	55,813
88	(561.4) Scheduling, System Control and Dispatch Services	1,460,340	
89	(561.5) Reliability, Planning and Standards Development	470	902
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	107,358	116,017
94	(563) Overhead Lines Expenses	16,744	103,310
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	15,553,606	14,117,924
97	(566) Miscellaneous Transmission Expenses	629,025	409,751
98	(567) Rents	1,668	618
99	TOTAL Operation (Enter Total of lines 83 thru 98)	18,436,340	15,319,122
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures	39,988	21,868
103	(569.1) Maintenance of Computer Hardware	2,499	1,182
104	(569.2) Maintenance of Computer Software	199,640	262,370
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	329,419	279,482
108	(571) Maintenance of Overhead Lines	409,659	299,887
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	981,205	864,789
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	19,417,545	16,183,911

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/13/2017	End of 2016/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	1,731,904	1,707,710
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	1,731,904	1,707,710
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	1,731,904	1,707,710
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	73,050	116,441
135	(581) Load Dispatching	415,043	408,671
136	(582) Station Expenses	180,635	242,979
137	(583) Overhead Line Expenses	457,035	411,742
138	(584) Underground Line Expenses	384,842	402,279
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	423,752	259,486
141	(587) Customer Installations Expenses	1,078,774	1,233,268
142	(588) Miscellaneous Expenses	2,469,103	1,861,461
143	(589) Rents	116,699	32,837
144	TOTAL Operation (Enter Total of lines 134 thru 143)	5,598,933	4,969,164
145	Maintenance		
146	(590) Maintenance Supervision and Engineering		1,473
147	(591) Maintenance of Structures	13,547	24,691
148	(592) Maintenance of Station Equipment	470,448	369,292
149	(593) Maintenance of Overhead Lines	5,716,388	5,950,958
150	(594) Maintenance of Underground Lines	291,514	328,761
151	(595) Maintenance of Line Transformers	32,259	37,047
152	(596) Maintenance of Street Lighting and Signal Systems	471,621	376,424
153	(597) Maintenance of Meters	334,178	390,567
154	(598) Maintenance of Miscellaneous Distribution Plant		81
155	TOTAL Maintenance (Total of lines 146 thru 154)	7,329,955	7,479,294
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	12,928,888	12,448,458
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	246,056	239,717
160	(902) Meter Reading Expenses	844,643	930,040
161	(903) Customer Records and Collection Expenses	4,810,532	4,664,976
162	(904) Uncollectible Accounts	316,593	762,801
163	(905) Miscellaneous Customer Accounts Expenses	455	1,083
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	6,218,279	6,598,617

THIS FILING IS

Item 1: [X] An Initial (Original) Submission OR [ ] Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature.

Exact Legal Name of Respondent (Company)	Year/Period of Report
Duke Energy Kentucky, Inc.	End of 2018/Q4

FERC FORM No.1/3-Q (REV. 02-04)

Name of Respondent Duke Energy Kentucky, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	392,525	409,170
63	(547) Fuel	8,541,559	1,920,479
64	(548) Generation Expenses	342,235	334,915
65	(549) Miscellaneous Other Power Generation Expenses	948,145	965,092
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	10,224,464	3,629,656
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	206,662	84,829
70	(552) Maintenance of Structures	392,714	280,302
71	(553) Maintenance of Generating and Electric Plant	247,356	2,387,546
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	326,663	296,614
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	1,173,395	3,049,291
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	11,397,859	6,678,947
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	75,625,084	31,557,546
77	(556) System Control and Load Dispatching	1,460	1,246
78	(557) Other Expenses	2,538,182	6,225,805
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	78,164,726	37,784,597
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	199,379,255	171,676,208
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,518	2,789
84			
85	(561.1) Load Dispatch-Reliability	93,821	94,788
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	435,265	435,117
87	(561.3) Load Dispatch-Transmission Service and Scheduling	59,242	59,082
88	(561.4) Scheduling, System Control and Dispatch Services	3,046,615	1,877,059
89	(561.5) Reliability, Planning and Standards Development		1,424
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	-6,392,346	666,832
93	(562) Station Expenses	148,685	111,250
94	(563) Overhead Lines Expenses	33,532	46,121
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	13,909,634	12,797,078
97	(566) Miscellaneous Transmission Expenses	486,517	481,220
98	(567) Rents		
99	TOTAL Operation (Enter Total of lines 83 thru 98)	11,823,483	16,572,760
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures	29,250	8,929
103	(569.1) Maintenance of Computer Hardware	1,011	615
104	(569.2) Maintenance of Computer Software	134,506	97,287
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	255,031	335,680
108	(571) Maintenance of Overhead Lines	428,751	230,761
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	2,108	
111	TOTAL Maintenance (Total of lines 101 thru 110)	850,657	673,272
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	12,674,140	17,246,032

Name of Respondent Duke Energy Kentucky, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2019	Year/Period of Report End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	1,689,716	1,870,407
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	1,689,716	1,870,407
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	1,689,716	1,870,407
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	116,063	45,381
135	(581) Load Dispatching	345,581	415,686
136	(582) Station Expenses	61,654	187,322
137	(583) Overhead Line Expenses	192,433	171,769
138	(584) Underground Line Expenses	318,756	405,387
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	625,332	837,430
141	(587) Customer Installations Expenses	961,447	623,309
142	(588) Miscellaneous Expenses	2,539,530	2,431,263
143	(589) Rents	-21,469	-28,173
144	TOTAL Operation (Enter Total of lines 134 thru 143)	5,139,327	5,089,374
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	84,317	
147	(591) Maintenance of Structures	8,247	4,020
148	(592) Maintenance of Station Equipment	302,347	314,089
149	(593) Maintenance of Overhead Lines	7,798,853	10,909,894
150	(594) Maintenance of Underground Lines	268,976	621,980
151	(595) Maintenance of Line Transformers	231,011	457,602
152	(596) Maintenance of Street Lighting and Signal Systems	352,595	458,640
153	(597) Maintenance of Meters	306,149	334,384
154	(598) Maintenance of Miscellaneous Distribution Plant	6,587	
155	TOTAL Maintenance (Total of lines 146 thru 154)	9,359,082	13,100,609
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	14,498,409	18,189,983
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	271,402	271,798
160	(902) Meter Reading Expenses	534,343	903,386
161	(903) Customer Records and Collection Expenses	4,195,665	4,302,161
162	(904) Uncollectible Accounts	-7,252	-35,509
163	(905) Miscellaneous Customer Accounts Expenses	381	451
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	4,994,539	5,442,287

VERIFICATION

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

The undersigned, William Don Wathen Jr., Director of Rates & Regulatory Strategy, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing rebuttal testimony and that it is true and correct to the best of his knowledge, information and belief.

William Don Wathen Jr., Affiant

Subscribed and sworn to before me by William Don Wathen Jr., on this 17TH day of JANUARY, 2020.

NOTARY PUBLIC

ADELE M. FRISCH
Notary Public, State of Ohio
My Commission Expires 01-05-2024

My Commission Expires: 1/5/2024