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August 12, 2022

ELECTRONICALLY FILED

Linda C. Bridwell
Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P.O. Box 615
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Case No. 2020-00174 (Post-Case Correspondence File)

Dear Ms. Bridwell:

Kentucky Power Company makes this filing in furtherance of Ordering Paragraph 14 of the Public Service Commission of Kentucky's February 22, 2021 Order on rehearing. It provides:

> Kentucky Power's motion for rehearing to clarify the timing of a future proceeding regarding the amortization of the Rockport Deferral Mechanism is granted to the limited extent to clarify the Commission will initiate a new proceeding to address the Rockport deferral mechanism regulatory asset once Kentucky Power makes a written filing identifying, by name, the capacity replacement for the Rockport UPA and the reasonably anticipated costs. With this clarification, this issue is closed.[1]

Kentucky Power proposes to obtain its initial capacity replacement for the Rockport UPA following its expiration on December 7, 2022 through, and under the terms and conditions of, the Power Coordination Bridge Agreement[2] ("PCBA") between Kentucky Power and the AEP Operating Companies.[3] The replacement capacity will be initially obtained, as described in more

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[1] Order, *In the Matter of: Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) Approval Of A Certificate Of Public Convenience And Necessity, And (5) All Other Required Approvals And Relief* at 29 Case No. 2020-00174 (Ky. P.S.C. February 22, 2021).

[2] The PCBA was filed with the Federal Energy Regulatory Commission on May 11, 2022.

[3] The AEP Operating Companies comprise Appalachian Power Company, Indiana Michigan Power Company, Kingsport Power Company, and Wheeling Power Company.

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detail below, for a period ending on or before May 31, 2024 (the end of the PJM Interconnection LLC 2023/2024 Fixed Resource Requirement Planning Year).[4]

The Company forecasts that with the expiration of the Rockport UPA it will require 152.4 MW of capacity through the 2022/2023 PJM planning year ending May 31, 2023.[5] The Company currently forecasts that it will require 70.2 MW of capacity through the PJM 2023/2024 planning year[6] ending May 31, 2024. The capacity for the 2022/2023 PJM planning year will be priced at the Base Residual Auction Clearing Price for that planning year of $50 per MW-day. The capacity for the 2023/2024 PJM planning year will be priced at the Base Residual Auction Clearing Price for that planning year of $34.13 per MW-day.

These capacity purchases through the PCBA are intended as an interim measure. Kentucky Power will file its 2022 Integrated Resource Plan ("IRP") with the Commission on or before December 20, 2022. The 2022 IRP will identify the Company's long-term plans for replacing the Rockport UPA capacity beyond the PJM 2023/2024 planning year.

The Settlement Agreement approved with non-relevant changes by the Commission's January 18, 2018 Order in Case No. 2017-00179[7] provided substantial benefits to Kentucky Power's customers. Chief among the benefits was the deferral of $50 million in FERC-approved Rockport UPA expenses during the period 2018-2022.[8] In return, the Settlement Agreement provides for the amortization of the deferred amount, with a WACC carrying charge, over five years.[9] It also provides for the Rockport Offset.[10]

The Commission's January 18, 2018 Order in Case No. 2017-00179 approving the settlement agreement is attached as Exhibit A to this filing. Attached as Exhibit B to this filing is the Settlement Agreement, including the exhibits to the agreement. Settlement Exhibit 2 is a sample calculation of the Rockport Offset agreed to by the settling parties.

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[4] The capacity will be obtained for a period of less than two years and thus Commission approval is not required. KRS 278.300(8).

[5] Kentucky Power's load obligation is 1,014.4 MW for the 2022/2023 PJM planning year.

[6] Kentucky Power forecasts a peak load obligation of 1,014.8 MW for the 2023/2024 PJM planning year.

[7] *In the Matter of: Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets Or Liabilities; And (5) An Order Granting All Other Required Approvals And Relief*, Case No. 2017-00179 at 37-40 (Ky. P.S.C. January 18, 2018).

[8] *Id*. at Appendix A ¶ 3(b). A copy of the relevant portions of the Commission's Order and the Settlement Agreement are appended to this letter.

[9] *Id*. at ¶ 3(c).

[10] *Id*. at ¶ 3(f).

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The Company relied on that approval in agreeing to the lower rates than it was entitled to under the law. Retroactively changing the Settlement Agreement after the customers have received the full benefit of the bargain struck in the agreement, and before the Company receives the quid pro quo for its agreement to accept lower rates in the near term raises serious legal and financial concerns.

The financial stability of a regulated utility is rooted not only in the Regulatory Compact but in the ability and reliance on receiving fair and just treatment by the regulator. The recovery of the Rockport Deferral in accordance with the terms of the Commission-approved Settlement Agreement is reflected in the financial projections for the Company and relied upon by financial institutions and credit rating agencies. If the terms of the Settlement Agreement are modified in a way that delays recovery of the Rockport Deferral, or reduces recovery of the Rockport Offset under the Commission-approved Settlement Agreement, Kentucky Power could face credit agency downgrades and increased borrowing costs – costs that would ultimately be borne by its customers. It is imperative to the financial health of the Company that the terms of the Settlement Agreement be honored as they were approved in the Commission's January 18, 2018 Order in Case No. 2017-00179.

Please do not hesitate to contact me if you have any questions.

Very truly yours,

STITES & HARBISON PLLC

Mark R. Overstreet

<u>EXHIBIT A</u>

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) AN ORDER APPROVING ITS 2017 ENVIRONMENTAL COMPLIANCE PLAN; (3) AN ORDER APPROVING ITS TARIFFS AND RIDERS; (4) AN ORDER APPROVING ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (5) AN ORDER GRANTING ALL OTHER REQUIRED APPROVALS AND RELIEF	)	CASE NO. 2017-00179

ORDER

Kentucky Power Company ("Kentucky Power"), a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP") is an electric utility that generates, transmits, distributes, and sells electricity to approximately 168,000 consumers in all or portions of 20 counties in eastern Kentucky.[1] Kentucky Power owns and operates a 285-megawatt ("MW") gas-fired steam-electric generating unit in Louisa, Kentucky, and owns and operates a 50 percent undivided interest in a coal-fired generating station in Moundsville, West Virginia; Kentucky Power's share consists of 780 MW. Kentucky Power obtains an additional 393 MW from Rockport (Indiana) Plant Generating Units No. 1 and No. 2 under a unit power agreement ("Rockport UPA"). Kentucky Power's transmission system is operated by PJM Interconnection, LLC ("PJM"), a regional

[1] Application at 2. Kentucky Power also furnishes electric service at wholesale to the Cities of Olive Hill and Vanceburg, Kentucky.

electric grid and market operator. Kentucky Power's most recent general rate increase was granted in June 2015 in Case No. 2014-00396.[2]

BACKGROUND

On April 26, 2017, Kentucky Power filed notice of its intent to file an Application ("Application") for approval of an increase in its electric rates based on a historical test year ending February 28, 2017. By Order entered May 24, 2017, the Commission granted Kentucky Power's motion to deviate from certain filing requirements, which Kentucky Power requested in order to obtain additional time to review its Application before its proposed filing date of June 28, 2017.

Kentucky Power tendered its Application on June 28, 2017, which included new rates to be effective on or after July 29, 2017, based on a request to increase its electric revenues by $65,387,987, or 11.80 percent. On August 7, 2017, Kentucky Power supplemented its Application to reflect the impact of refinancing of certain debts in June 2017, which reduced Kentucky Power's requested annual increase in revenues to $60,397,438. In its Application, Kentucky Power also requested approval of its environmental compliance plan, and proposed to revise, add, and delete various tariffs applicable to its electric service. After Kentucky Power cured filing deficiencies, its Application was deemed filed as of July 20, 2017. To determine the reasonableness of these requests, the Commission suspended the proposed rates for five months from their effective date, pursuant to KRS 278.190(2), up to and including January 18, 2018.

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[2] Case No. 2014-00396, *Application of Kentucky Power Company for: (1) A General Adjustment of Its Rates for Electric Service; (2) An Order Approving Its 2014 Environmental Compliance Plan; (3) An Order Approving Its Tariffs and Riders; and (4) An Order Granting All Other Required Approvals and Relief* (Ky. PSC June 22, 2015) ("Case No. 2014-00396, Final Order").

The following parties requested and were granted full intervention: the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("Attorney General"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Kentucky School Boards Association ("KSBA"); Kentucky League of Cities ("KLC"); Kentucky Commercial Utility Customers, Inc. ("KCUC"); Kentucky Cable Telecommunications Association ("KCTA"); and Wal-Mart Stores East, LP and Sam's East, Inc. (jointly, "Walmart").

By order entered on July 17, 2017, the Commission established a procedural schedule that provided for discovery, intervenor testimony, rebuttal testimony from Kentucky Power,[3] a formal evidentiary hearing, and an opportunity for the parties to file post hearing briefs.[4] On October 26, 2017, and November 7, 2017, an informal conference ("IC") was held at the Commission's offices to discuss procedural matters and the possible resolution of pending issues. All parties participated in the IC held on October 26, 2017, with the exception of KCTA, who engaged in separate discussions with Kentucky Power regarding possible resolution of issues pertaining to the Cable Television Pole Attachment Tariff ("Tariff C.A.T.V.") The Attorney General did not attend the November 7, 2017 IC due to a scheduling conflict, but indicated that the IC should proceed as scheduled. At the November 7, 2017 IC, the parties in attendance,

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[3] On October 11, 2017, the Attorney General filed a motion to amend the procedural schedule to permit him to file rebuttal testimony. Kentucky Power and KLC each filed responses in opposition. By order issued October 24, 2017, the Commission found the Attorney General failed to establish good cause to amend the procedural schedule and denied the Attorney General's motion.

[4] The Commission conducted public meetings in Kentucky Power's service territory on November 2, 2017, in Prestonsburg, Kentucky; on November 6, 2017, in Hazard, Kentucky; and on November 8, 2017, in Ashland, Kentucky.

with the exception of KCUC, arrived at an agreement in principle for the resolution of the issues raised in this case.

On November 22, 2017, Kentucky Power, KIUC, KLC, KSBA, KCTA, and Walmart ("Settling Intervenors") filed a Settlement Agreement ("Settlement") that addressed all of the issues raised in this proceeding. The Attorney General and KCUC are not signatories to the Settlement. The Settlement is attached as Appendix A to this Order.

Because the Settlement was not unanimous, the December 6, 2017, evidentiary hearing was held as scheduled for the purposes of hearing testimony in support of the Settlement and on contested issues. On January 5, 2018, Kentucky Power, the Attorney General, KIUC, and KCUC filed their respective post hearing briefs. The matter now stands submitted to the Commission for a decision.

SETTLEMENT AGREEMENT

The Settlement reflects the agreement of the parties, except for the Attorney General and KCUC, on all issues raised in this case. The major substantive areas addressed in the Settlement are as follow:

- Kentucky Power's electric retail revenues should be increased by $31,780,734, effective January 19, 2018.[5] This amount consists of a base rate revenue reduction of $28,616,704 from the $60,397,438 requested in Kentucky Power's August 7, 2017 supplemental filing.

[5] Settlement, paragraphs 2(a) and 17.

- Establishment of deferral mechanisms for $50 million in non-fuel, non-environmental Rockport UPA expenses.[6]

- Amendment of the Purchase Power Adjustment tariff ("Tariff P.P.A.") to recover incremental PJM Open Access Transmission Tariff ("OATT") Load Serving Entity ("LSE") charges and credits above or below net PJM OATT LSE charges and credits in base rates.[7]

- Amendment of Tariff P.P.A. as described in the Direct Testimony of Alex E. Vaughan ("Vaughan Direct Testimony") to collect from, or credit to, customers the amount of purchased power costs that are excluded from recovery through the Fuel Adjustment Clause ("FAC"), and gains and losses from incidental sales of natural gas purchased for use at Big Sandy Unit 1, but not used or stored.[8]

- Establishment of 20-year service life for Big Sandy Unit 1 for depreciation rates.[9]

- Establishment of a return on equity of 9.75 percent.[10]

- Agreement to lower the Kentucky Economic Development Surcharge rate ("Tariff K.E.D.S.") for residential customers and increase the rate for non-residential customers, with matching contribution by Kentucky Power.[11]

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[6] *Id.* at paragraph 3.

[7] *Id.* at paragraph 4.

[8] *Id.* at paragraph 6.

[9] *Id.* at paragraph 7.

[10] *Id.* at paragraph 8.

[11] *Id.* at paragraph 10.

- Agreement to continue Tariff K-12 School as a permanent customer class instead of a pilot rate.[12]

- Agreement that Kentucky Power will not request a general adjustment of base rates for rates that would be effective prior to the January 2021 billing cycle.[13]

- Increase Kentucky Power's customer charge for Residential Service customers to $14.00 per month.[14]

CONTESTED REVENUE REQUIREMENT AND REVENUE ALLOCATION ISSUES

Kentucky Power proposed an annual increase in its electric revenues of $60,397,438 in its August 7, 2017 supplemental filing. Through testimony, the Attorney General contended that Kentucky Power should be allowed to increase its electric revenues by $39.9 million.[15] Through testimony, KCUC contended that the revenue allocation contained in the Settlement does not provide fair or reasonable treatment for customers in the Large General Service class ("Tariff L.G.S."). Because the parties have not reached a unanimous settlement on the increase in revenues, the Commission must consider the evidentiary record on these issues as presented by Kentucky Power, the Attorney General, and KCUC, and render a decision based on a determination of Kentucky Power's capital, rate base, operating revenues, operating expenses, and revenue allocation, as would be done in a fully litigated rate case

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[12] *Id.* at paragraphs 1213.

[13] *Id.* at paragraph 5.

[14] *Id.* at paragraph 16.

[15] Direct Testimony of Ralph C. Smith ("Smith Testimony") at 12.

TEST PERIOD

Kentucky Power proposed the 12-month period ending February 28, 2017, as the test period for determining the reasonableness of its proposed rates. None of the Intervenors contested the use of this period as the test period. The Commission finds it is reasonable to use the 12-month period ending February 28, 2017, as the test period in this case. Due to the timing of Kentucky Power's filing, the 12-month period ending February 28, 2017, is the most recent feasible period to use for setting rates and, except for the adjustments approved herein, the revenues and expenses incurred during that period are neither unusual nor extraordinary.[16] In using this historic test period, the Commission has given full consideration to appropriate known and measurable changes.

RATE BASE

Jurisdictional Rate Base Ratio

Kentucky Power proposed a test-year-end Kentucky jurisdictional rate base of \$1,323,494,246.[17] The Kentucky jurisdictional rate base is divided by Kentucky Power's test-year-end total company rate base to derive the Kentucky jurisdictional rate base ratio ("jurisdictional ratio"). This jurisdictional ratio is then applied to Kentucky Power's total company capitalization to derive the Kentucky jurisdictional capitalization. The jurisdictional ratio uses the test-year-end rate base before any ratemaking adjustments

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[16] On May 22, 2017, Kentucky Power filed a motion to deviate from filing requirement 807 KAR 5:001, Section 12(1)(a), which requires the submission of a detailed financial exhibit for the 12-month test period ending not more than 90 days prior to the date of its application. Kentucky Power requested to deviate by filing the required financial exhibit for 12-month period ending 120 days, rather than 90 days, prior to the date of its application. By Order, the Commission approved Kentucky Power's motion to deviate from 807 KAR 5:001, Section 12(1)(a) (Ky. PSC May 24, 2017).

[17] Application, Section V, Exhibit 1, Schedule 4.

applicable to either Kentucky jurisdictional operations or other jurisdictional operations. Kentucky Power used a jurisdictional ratio of 98.3 percent.[18] The Commission finds the calculation of Kentucky Power's test-year electric rate base reasonable for purposes of establishing the jurisdictional ratio.

Pro Forma Jurisdictional Rate Base

Kentucky Power calculated a pro forma jurisdictional rate base of $1,194,888,447,[19] which reflects the types of adjustments made by the Commission in prior rate cases to determine the pro forma rate base.

The Attorney General proposed one adjustment to Kentucky Power's proposed rate base for the Cash Working Capital ("CWC") allowance. The Attorney General proposed an allowance of $18,953,980, which is $740,459 lower than the $19,694,529 proposed by Kentucky Power in its Application. While indicating a preference for using a lead-lag study, the Attorney General stated that if CWC is to be calculated using the Commission's long-standing 1/8th formula approach, then the proper level of CWC for ratemaking purposes should be based on the pro forma operations and maintenance expenses allowed by the Commission.[20] The Attorney General also stated that since Kentucky Power's revenue requirement is calculated based upon its jurisdictional capitalization rather than its adjusted jurisdictional rate base, any adjustment to CWC would have no impact on the revenue requirement.[21]

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[18] *Id.* The non-jurisdictional percentage of approximately 1.7 percent is due to the furnishing of electric service at wholesale to the City of Olive Hill and the City of Vanceburg.

[19] *Id.*

[20] Smith Testimony at 22.

[21] *Id.* at 23.

While the Commission agrees with the methodology the Attorney General utilized for calculating the CWC, the Commission does not agree with the Attorney General's proposed CWC. The CWC allowance included in the rate base, as shown below, is based on the adjusted operation and maintenance ("O&M") expenses discussed in this Order, as approved by the Commission. The Commission has determined Kentucky Power's pro forma jurisdictional rate base for ratemaking purposes for the test year to be as follows:

Total Utility Plant in Service	$2,264,648,845
Add:	
Materials & Supplies	36,344,575
Prepayments	49,905,719
Cash Working Capital Allowance	18,905,292
Subtotal	$105,155,586
Deduct:	
Accumulated Depreciation	764,544,392
Customer Advances	27,076,876
Accumulated Deferred Income Taxes	384,084,108
Contributions in Aid of Construction	
Subtotal	$1,175,705,376
Pro Forma Rate Base	$1,194,099,055

Reproduction Cost Rate Base

KRS 278.290 (1) states, in relevant part, that:

> [T]he commission shall give due consideration to the history and development of the utility and its property, original cost, cost of reproduction as a going concern, capital structure, and other elements of value recognized by the law of the land for ratemaking purposes.

Neither Kentucky Power, the Attorney General, nor KCUC provided information regarding Kentucky Power's proposed Kentucky jurisdictional reproduction cost rate base. Therefore, the Commission finds that using Kentucky Power's historic costs for deriving its rate base is appropriate and consistent with Commission precedent involving Kentucky Power, as well as other Kentucky jurisdictional utilities.

CAPITALIZATION

Kentucky Power proposed an adjusted Kentucky jurisdictional capitalization of $1,191,785,493.[22] This amount was derived through adjustments to exclude certain environmental compliance investments that remain part of the environmental rate base and are included in Kentucky Power's environmental surcharge mechanism.

Kentucky Power determined its electric capitalization by multiplying its total company capitalization by the rate base jurisdictional allocation ratio described earlier in this Order. This is consistent with the approach used in previous Kentucky Power rate cases.

The Attorney General did not recommend any adjustments to Kentucky Power's capitalization. The Attorney General proposed one adjustment to rate base for CWC, since it does not affect Kentucky Power's jurisdictional capitalization, but recommended no change to the amount proposed by Kentucky Power.

The Commission finds the proposed amount of Kentucky Power's jurisdictional capitalization is reasonable.

REVENUES AND EXPENSES

For the test year, Kentucky Power reported actual net operating income from its electric operations of $85,033,742.[23] Kentucky Power proposed 55 adjustments to

[22] Application, Section II, Exhibit L.

[23] Application, Section V, Exhibit 1, Supplemental Schedule 4 (filed Aug. 7, 2017).

revenues and expenses to reflect more current and anticipated operating conditions, resulting in an adjusted net operating income of $43,690,670.[24] With this level of net operating income, Kentucky Power reported an adjusted test year revenue deficiency of $60,397,438.[25]

The Attorney General accepted 45 of Kentucky Power's proposed adjustments to its test-year revenues and expenses.

A list of the non-contested adjustments is contained in Appendix B to this Order. The Attorney General proposed 14 additional adjustments to Kentucky Power's operating income relating to: 1) theft recovery revenue; 2) payroll expense – employee merit increase; 3) overtime payroll expense related to employee merit increase; 4) payroll tax expense; 5) incentive compensation expense; 6) stock-based compensation; 7) savings plan expense; 8) supplemental executive retirement program expense; 9) affiliate charge for corporate aviation expense; 10) storm damage expense; 11) relocation expense; 12) gain on sale of utility property; 13) cash surrender value of life insurance policies; and 14) rate case expense.

The Attorney General's proposed adjustments pertain solely to Kentucky Power's base rate revenue requirements. The Commission makes the following determinations regarding the Attorney General's proposed base rate adjustments.

Theft Recovery Revenue

The Attorney General proposed an adjustment to increase Kentucky Power's theft recovery revenue by $166,698 based upon Kentucky Power's estimate of

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[24] *Id.*

[25] *Id.* at Schedule V, Supplemental Exhibit 2 (filed Aug. 7, 2017).

increased theft recovery revenue.[26] Kentucky Power expects to increase theft recovery revenue due to the addition of a new administrative assistant who would allow Kentucky Power's field investigators to spend more time on suspected energy theft.

The Commission finds that the Attorney General's proposed adjustment regarding theft recovery revenue is reasonable, and therefore the proposed adjustment for theft recovery revenue of $166,698 should be allowed for ratemaking purposes.

Payroll Expenses: Employee Merit Increase, Overtime Payroll Expense, and Payroll Taxes

The Attorney General proposed adjustments to payroll expense for employee merit increases for non-exempt salaried employees, overtime payroll expense related to employee merit increases, and associated payroll taxes in the amount of $57,205, $4,148, and $48,362, respectively. The Attorney General argued that Kentucky Power did not justify basing its proposed payroll expense adjustment on an annual merit increase of 3.5 percent. The Attorney General maintained that the payroll expense adjustment should be based upon a 3.0 percent merit increase.[27] Limiting the merit increase to 3.0 percent results in corresponding adjustments to overtime and payroll tax expenses. The payroll tax adjustment includes the impact of limiting the merit increase to 3.0 percent and other adjustments to incentive compensation and stock-based compensation proposed by the Attorney General.

Kentucky Power maintained that the test year wage increases are reasonable. A comparison of Kentucky Power's total target compensation with the 2016 EAPDIS

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[26] Smith Testimony at 24; Kentucky Power's Response to the Attorney General's First Request for Information ("Attorney General's First Request"), Item 319.

[27] *Id.* at 26-30.

Energy, Technical, Craft & Clerical Survey (Southeast region data) reveals that, on average, Kentucky Power's compensation was 5.4 percent below the average for the region.[28] Kentucky Power claimed that, in light of the survey results, the test year wage increases were necessary to provide market competitive wages to target and retain employees.

The Commission finds that Kentucky Power's test year wages are reasonable and that the Attorney General's proposed adjustments to payroll expense for employee merit increases for non-exempt salaried employees, overtime payroll expense related to employee merit increase and payroll taxes should be denied.

Incentive Compensation and Stock Based Compensation

Kentucky Power included $3,900,806 of incentive compensation plan ("ICP") costs[29] and $1,758,874 in Long-Term Incentive Plan ("LTIP") costs in its Kentucky jurisdictional revenue requirement.[30] These amounts reflect the adjustments made by Kentucky Power.[31] In the Settlement, Kentucky Power and the Settling Intervenors agreed to reduce incentive compensation expenses by $3.15 million, which included incentive compensation and stock-based compensation.

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[28] Application, Direct Testimony of Andrew J. Carlin ("Carlin Direct Testimony"), Exhibit ARC-4.

[29] Kentucky Power's Response to Commission Staff's Second Request for Information (Staff's Second Request"), Item 85; Kentucky Power's Response to KIUC's First Request for Information ("KIUC's First Request"), Item 31.

[30] Smith Testimony at 31. This consists of Kentucky Power direct-charged jurisdictional O&M expense of $2,255,760, AEP allocated amount of $3,118,781 and charges from other affiliates of $51,300 less $1,525,035 that was removed from the revenue requirement per the Application, Section V, Exhibit 2, Workpaper 32.

[31] Application, Direct Testimony of Tyler H. Ross ("Ross Direct Testimony") at 14.

The Attorney General recommended reducing incentive compensation expense by a total of $3,096,868. The Attorney General recommended an adjustment of ICP costs that decreased test year expense by $1,350,120 on a Kentucky jurisdictional basis, which represented the removal of the 25 percent of ICP costs that represent performance measures tied to increasing shareholder value.[32] The Attorney General maintained that ratepayers should not be responsible for those costs because Kentucky Power's shareholders are the main beneficiaries of the 25 percent performance measure for quantitative financial objectives, which include earnings per share.[33] Similarly, the Attorney General argued that $1,746,748 in stock-based compensation costs should be removed because ratepayers should not be required to pay management compensation based on the performance of Kentucky Power's stock price, which primarily benefits Kentucky Power's parent company.[34] In support of his argument, the Attorney General pointed to previous cases in which the Commission held that ratepayers should not bear the cost of stock-based compensation programs unless there is clear and definitive quantitative evidence demonstrating a benefit to ratepayers.[35]

In response, Kentucky Power argued that the Attorney General's adjustment to the proposed incentive compensation expense was not warranted because the

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[32] Smith Testimony at 35, Exhibit RCS-1, page 3 of 32; Smith Testimony at 30-31. The 2016 ICP was weighted 75 percent to AEP's earnings per share and 25 percent to other metrics

[33] *Id.* at 31.

[34] *Id.* at 39.

[35] Case No. 2014-00397, Final Order at 27-28; Case No. 2005-00042, *An Adjustment of the Gas Rates of the Union Light, Heat and Power Company* (Ky. PSC Feb. 2, 2006); Case No. 2010-00036, *Application of Kentucky-American Water Company for an Adjustment of Rates Supported by a Fully Forecasted Test Year* (Ky. PSC Dec. 14, 2010).

incentive compensation programs provide benefits to both Kentucky Power's customers and its shareholders.[36]

The Commission finds that the Settlement provision that reduces incentive compensation by $3.15 million, which is a greater reduction than the adjustment recommended by the Attorney General, is reasonable and should be approved.

Savings Plan Expense

Kentucky Power included $1,662,975 in its jurisdictional revenue requirement for savings plan expense for employees who participate in a defined benefit plan and have matching 401(k) contributions from Kentucky Power.[37]

The Attorney General proposed a Kentucky jurisdictional adjustment of $1,102,496 for savings plan expense for employees who participate in a defined benefit plan and have matching 401(k) contributions from Kentucky Power.

In rebuttal, Kentucky Power explained that participation in the defined benefit plan ended in 2000 and benefits were frozen in 2010.[38] Therefore, Kentucky Power does not contribute to a defined benefit plan and 401(k) matching plan at the same time. The Commission has disallowed such matching contributions when both a defined benefit plan and 401(k) matching contribution exist concurrently. This is not the case with Kentucky Power.

The Commission finds that Kentucky Power's savings plan expense is reasonable and should be allowed for ratemaking purposes.

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[36] Rebuttal Testimony of Andrew R. Carlin ("Carlin Rebuttal Testimony") at 7.

[37] Kentucky Power's Response to Staff's Second Request, Item 56.h. and i.

[38] Dec. 7, 2017 H.V.T. at 4:50:20.

Supplemental Executive Retirement Plan ("SERP")

The Attorney General proposed an adjustment of $52,453 for the expense associated with Kentucky Power's Supplemental Executive Retirement Plan ("SERP"). The Attorney General argued that such plans provide benefits to executives that exceed amounts limited in qualified retirement plans by the Internal Revenue Service.[39] The Attorney General also maintained that the provision of additional retirement compensation to Kentucky Power's highest paid executives is not a reasonable expense that should be recovered in rates.

In rebuttal, Kentucky Power stated that the total benefit it provides under both its qualified and non-qualified plan is equal to the benefit that would be produced by the formulas utilized under the qualified plans if these plans were not subject to the benefit limitations imposed on qualified plans.[40]

The Commission finds the SERP expenses reasonable and, therefore, should be allowed for ratemaking purposes.

Affiliate Charge for Corporate Aviation Expense

The Attorney General proposed an adjustment of $382,769 to remove the cost of the AEP corporate aviation expense charged to Kentucky Power during the test year.[41] The Attorney General argued that AEP corporate aviation is a perquisite for AEP executives and directors and, as such, shareholders should bear the cost, not ratepayers.

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[39] Smith Testimony at 42.

[40] Carlin Rebuttal Testimony at R-32.

[41] Smith Testimony at 43-44.

The Commission disagrees with the Attorney General's proposed adjustment for corporate aviation expense. While private jet travel may appear to be an extravagance, legitimate travel expenses would have been incurred through commercial airlines. The Commissions finds that the aviation expense proposed by Kentucky Power is reasonable and should be approved.

Storm Damage Expense

Kentucky Power proposed an adjustment of $595,932 for storm damage expense based upon a three-year average of major storm expense. The Attorney General proposed an adjustment to reduce storm damage expense by $595,932, arguing that Kentucky Power had not demonstrated a compelling reason to increase test year storm damage expense.[42]

Kentucky Power explained that it used a three-year average to normalize the level of costs to address the uncertainty regarding when, and how much, a major storm will affect Kentucky Power and because using only the test year amount in a base rate filing could lead to major swings in adjustments for storm damage expense.[43]

The Commission finds that Kentucky Power's storm damage expense adjustment is reasonable and should be allowed for ratemaking purposes.

Test Year Relocation Expense

Kentucky Power included a $318,073 adjustment for relocation expense in its test year revenue requirement.[44] The Attorney General proposed an adjustment to

[42] *Id.* at 44.

[43] Rebuttal Testimony of Ranie K. Wohnhas ("Wohnhas Rebuttal Testimony") at R-18 – R-19.

[44] Kentucky Power's Response to the Attorney General's First Request, Item 251.

normalize relocation expenses that reduced the test year operating expenses by $140,972 on a Kentucky jurisdictional basis.[45]

In response to Commission Staff's Post-Hearing Data Request, Item 14, Kentucky Power stated that its relocation expense for the eight-month period March 1, 2017 to October 31, 2017 totaled $125,736. Annualized over a twelve-month period ending February 28, 2018, relocation expenses are forecasted to total $188,604. On a Kentucky jurisdictional basis, relocation expenses for the twelve months ending February 28, 2018 amount to $185,964.

The Commission finds that the relocation expense should be adjusted based upon the Kentucky jurisdictional relocation expenses for the twelve months ending February 28, 2018. This results in a decrease to the Kentucky jurisdictional relocation expense of $132,109.

Gain on Sale of Utility Property

The Attorney General proposed an adjustment to amortize a $996,669 gain on the sale of utility property ("Carrs Site") over three years for $327,240 per year on a Kentucky jurisdictional basis.[46] The Attorney General maintained that the Kentucky jurisdictional gain on the sale of utility property should flow back to customers.

In rebuttal, Kentucky Power argued that the gain on the sale of the property should not be adjusted to reduce its revenue requirement because the Carrs Site had not been included in rate base, and thus Kentucky Power had not received a return on

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[45] Smith Testimony at 46.

[46] *Id.* at 47.

the Carrs Site for the last 33 years.[47] Kentucky Power also noted that it removed $60,539 in property taxes from its cost of service in this case.[48]

The Commission finds that, since Kentucky Power has not received a return on this investment and has excluded the property taxes from its cost of service, the proposed adjustment by the Attorney General is not reasonable and should be denied.

Cash Surrender Value of Life Insurance

Kentucky Power recorded expense in the test year associated with the cash surrender value of life insurance of former executives in a Kentucky jurisdictional amount of $26,941.[49]

The Attorney General asserted that Kentucky Power's ratepayers should not be responsible for paying the expenses for the cash surrender value of life insurance for former executives and recommended the $26,941 of expense be denied for ratemaking purposes.[50]

In rebuttal, Kentucky Power explained that the expense is part of the total compensation/benefit package given to executives (current or former) that should be recovered whether or not the executive is a current or a former employee.[51]

The Commission finds that the proposed expense is reasonable, and therefore the Attorney General's proposed adjustment should be denied.

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[47] Wohnhas Rebuttal Testimony at R-20.

[48] *Id.*

[49] Smith Testimony at 48.

[50] *Id.*

Rate Case Expense

The Attorney General proposed an adjustment to remove $458,333 in rate case expenses.[52] The Attorney General proposed to remove certain rate case expenses billed by a consultant who conducted witness preparation but did not sponsor testimony on Kentucky Power's behalf. The Attorney General also proposed to remove remaining rate case expenses as a penalty for Kentucky Power not seeking a reduction in the Rockport UPA ROE, which was established by the Federal Energy Regulatory Commission ("FERC").

In rebuttal, Kentucky Power argued that witness preparation is a necessary part of litigating a base rate case and that, regardless of who performs the function, the cost should be recovered.[53] Kentucky Power further argued that FERC's determination of the Rockport UPA ROE was fair, just, and reasonable, and that the decision was within FERC's exclusive jurisdiction. Kentucky Power asserted that the Attorney General's proposal to deny rate case expense as a penalty for the Rockport UPA ROE was an unlawful and unconstitutional attempt to overturn a FERC decision.

The Commission finds that the Attorney General's adjustment to remove rate case expenses for witness preparation and as a penalty for the Rockport UPA ROE is unreasonable, and should be denied. Given the type of service provided, the Attorney General's argument to remove the witness preparation consultant's fees is not

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[51] Wohnhas Rebuttal Testimony at 17.

[52] Smith Testimony at 52.

[53] Wohnhas Rebuttal Testimony at R-20.

persuasive.[54] In regard to adjusting the rate case expenses as a penalty not related to ratemaking, as set forth in *South Central Bell v. Utility Reg. Comm'n*, 637 S.W.2d 649, 653 (Ky. 1982), the imposition of penalty that is not germane to the factors that go into the ratemaking process is arbitrary and subjective. If the Attorney General objects to the ROE awarded by FERC, the appropriate forum to address that issue is at FERC, and not the Commission.

COMMISSION ADJUSTMENTS TO REVENUES AND EXPENSES

Off System Sales ("OSS") Margins, System Sales Clause Tariff ("Tariff S.S.C.")

During the test year, Kentucky Power included OSS margins in the amount of $7,163,948. Kentucky Power operated the converted Big Sandy Unit 1 for only nine months of the test period. While Kentucky Power annualized the plant maintenance expense for Big Sandy Unit 1,[55] there was no adjustment or annualization to OSS margins.

The Commission finds that OSS margins should be adjusted to reflect an annualized amount. For the 12-month period ending September 30, 2017, Kentucky Power had OSS margins of $7,650,360.[56] Therefore, the Commission will utilize the OSS margins of $7,650,360 for the 12-month period ending September 30, 2017, rather than the test year amount, resulting in an increase in operating revenue of $486,412. Additionally, the amount of OSS margins to be collected in base rates is $7,650,360, rather than the $7,163,948 proposed in the application.

[54] *See* Kentucky Power Fifth Supplemental Response to Staff's First Request (filed Jan. 2, 2018), Item 56. The witness preparation fees were $42,623; Kentucky Power's other legal fees were $677,547.

[55] Application, Section V, Exhibit 2, Workpaper 41.

[56] Response to Commission Staff's Fourth Request for Information, Item 2.

Weather Normalized Commercial Sales

Kentucky Power proposed an adjustment to increase revenues to reflect normal temperatures, but its adjustment applied only to residential customer sales. In discovery, Kentucky Power stated that commercial revenues would have been $914,000 greater based on weather normalized temperatures.[57] After the related variable expenses are removed from revenues, the rate increase is reduced by $400,000.

The Commission finds this adjustment reasonable as temperatures affect the revenues in both the residential and commercial classes. Therefore, the Commission will reduce the rate increase by $400,000 to reflect this adjustment.

Purchased Power Limitation and Forced Outage Purchase Power Limitation Expense

Kentucky Power proposed adjustments to include the purchased power limitation and forced outage purchase power limitation expense in base rates in its application in the amount of $3,150,582 and $882,204, respectively.

As discussed under the FAC Purchase Power Limitation section below, the Commission is denying Kentucky Power's proposal to recover such costs under Tariff P.P.A. Accordingly, the Commission finds these adjustments unreasonable and should be denied.

Net Operating Income Summary

After considering all pro forma adjustments and applicable income taxes, Kentucky Power's adjusted net operating income is as follows:

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[57] Direct Testimony of Lane Kollen at 16-17.

Operating Revenues	$568,163,551
Operating Expenses	519,965,870
Adjusted Net Operating Income	$ 48,197,681

RATE OF RETURN

Capital Structure and Cost of Debt

Kentucky Power proposed an adjusted test-year-end capital structure consisting of 54.45 percent long-term debt at 5.32 percent; zero percent short-term debt at 0.80 percent; 3.87 percent accounts receivable financing at 1.95 percent; and 41.68 percent common equity at a return of 10.31 percent.[58] On August 7, 2017, Kentucky Power filed a supplement to its Application reflecting the results of Kentucky Power's June 2017 refinancing of $325 million 6.00 percent Senior Unsecured Notes, and $65 million WVEDA Mitchell Project, Series 2014A Variable Rate Demand Notes as authorized in Case No. 2016-00345.[59] This refinancing reduced the annual cost of long-term debt to 4.36 percent.[60] The capital structure proposed by the Settlement downwardly adjusts the long-term debt by one percent and places this percent onto the short-term debt at an interest rate of 1.25 percent.[61]

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[58] Application, Direct Testimony of Zachary C. Miller ("Miller Direct Testimony") at 3.

[59] Case No. 2016-00345 *Electronic Application of Kentucky Power Company for Authority Pursuant to KRS 278.300 to Issue and Sell Promissory Notes of One or More Series and for Other Authorizations* (Ky. PSC Dec. 21, 2016).

[60] Supplemental Direct Testimony of Zachary C. Miller at 5.

[61] Settlement Testimony of Mattew J. Satterwhite ("Satterwhite Settlement Testimony") at Exhibit 6a.

The Attorney General employed Kentucky Power's proposed capital structure and senior capital cost rates.[62] KCUC was silent on this topic.

Kentucky Power stated that it sells its receivables to AEP for cost savings due to default risks and to improve cash flow.[63] However, Kentucky Power's uncollectible accounts remain with Kentucky Power and are not sold with the accounts receivable.[64] The Commission notes that the cost of accounts receivable financing is higher than traditional short-term financing. The Commission believes that selling the receivables but maintaining the bad debt places an undue burden onto Kentucky Power's customers. Therefore, the Commission will blend the funds between short-term debt and accounts receivable financing so that the weighted average cost percentage of accounts receivable financing is decreased three basis points and placed on the short-term debt weighted average cost percentage. This reduces the percent of accounts receivable financing to 1.67 percent of the total capital structure and increases the percent of short-term debt to 3.20 percent of the total capital structure. The Commission finds that the cost of long-term debt and short-term debt of 4.36 percent and 1.25 percent, respectively, to be reasonable.

Return on Equity

In its Application, Kentucky Power developed its return on equity ("ROE") using the discounted cash flow method ("DCF"), the capital asset pricing model ("CAPM"), the empirical capital asset pricing model ("ECAPM"), and the utility risk premium ("RP"). In

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[62] Direct Testimony of J. Randall Woolridge, Ph.D. ("Woolridge Testimony") at 3.

[63] Dec. 8, 2017 H.V.T. at 12:15:22.

[64] Dec. 6, 2017 H.V.T. at 5:43:36.

addition, Kentucky Power referenced the expected earnings approach.[65] Based on the results of the methods employed in its analysis, Kentucky Power recommended an ROE range of 9.71 percent to 10.91 percent, including flotation cost.[66] Kentucky Power recommended awarding the midpoint of this range, 10.31 percent, to maintain financial integrity and to support additional capital investment.[67] Kentucky Power further stressed that consideration of all models, not just the DCF model, is important as the DCF model results may reflect the impact from the recent recession and such financial inputs are not representative of what may prevail in the near future.[68]

Direct testimony and analysis regarding ROE was provided by the Attorney General. The Attorney General employed the DCF and CAPM models for his analysis and both models were evaluated using Kentucky Power's proxy group and the Attorney General's own proxy group. This was mostly for comparison purposes, as the Attorney General stated that, on balance, the two proxy groups were similar in risk.[69] The Attorney General's DCF model results indicated equity cost rates of 8.25 percent and 8.7 percent for the Attorney General and Kentucky Power proxy groups, respectively. The Attorney General disagreed with Kentucky Power's DCF analysis, specifically noting Kentucky Power's elimination of low-end DCF results and the use of growth forecasts that the Attorney General believes are overly optimistic and upwardly biased.[70]

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[65] Application, Direct Testimony of Adrian M. McKenzie, CFA ("McKenzie Direct Testimony") at 6.

[66] *Id.* at Exhibit AMM-2 at 1.

[67] Id. at 6.

[68] Id. at 7.

[69] *Id.* at 25.

[70] *Id.* at 65.

The Attorney General's CAPM results were 7.6 percent for both proxy groups. The Attorney General stated that Kentucky Power's CAPM analysis is flawed as the ECAPM version of the CAPM was used, which the Attorney General claims makes an inappropriate adjustment to the risk-free rate and the market risk premium.[71] Additionally, the Attorney General stated that Kentucky Power's CAPM analysis employed an inflated projected interest rate, an unwarranted size adjustment, and an excessive market or equity risk premium.[72]

The Attorney General recommended relying primarily on the DCF model, determined the ROE range of the two proxy groups, 8.25 percent and 8.7 percent, to be reasonable, and recommended an ROE of 8.6 percent.[73] In support of his recommendation, the Attorney General noted that: as investment risk, Kentucky Power's credit ratings are on par with the proxy groups; capital costs for utilities remain at historical low levels and are likely to remain at low levels; the risk associated with the electric utility industry is among the lowest and, as such, the cost of equity capital is amongst the lowest; and authorized ROEs have been gradually decreasing in recent years.[74]

The Attorney General also disagreed with Kentucky Power's upward adjustment of 0.11 percent to the equity cost rate recommendation to account for flotation costs. The Attorney General argued that Kentucky Power did not identify any flotation costs

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[71] *Id.* at 68.

[72] *Id.*

[73] Woolridge Testimony at 58.

[74] *Id.* at 59.

that are specifically associated with Kentucky Power.[75] The Attorney General stated that it is commonly argued that a flotation cost adjustment is necessary to recover issuance costs, but should not be recovered through the regulatory process, as these costs are already known to the investor upon buying the stock.[76]

The parties to the Settlement agreed that the revenue requirement increases for Kentucky Power will reflect a 9.75 percent ROE as applied to Kentucky Power's capitalization and capital structure of the proposed revenue requirement increases as modified through discovery. As a result, use of a 9.75 percent ROE reduced Kentucky Power's proposed electric revenue requirement by $4.7 million.[77] In his post hearing brief, the Attorney General recognized the significant reduction from the original ROE, but still believes it is in excess of the return shareholders require.[78] The Attorney General further argued that utilities seem to overstate necessary ROE, and does not support the 9.75 percent.[79] For the reasons discussed below, the Commission finds a ROE of 9.75 percent to be unreasonable, and for the purpose of base rate revenues and certain tariffs, an ROE of 9.70 percent should be applied.

In his testimony, the Attorney General noted that differing opinions between Kentucky Power and the Attorney General regarding capital market conditions result in differing ROE recommendations.[80] Kentucky Power's analysis assumes higher interest

[75] *Id.* at 80.

[76] *Id.* at 81.

[77] Settlement at 4.

[78] Attorney General's Post Hearing Brief ("Attorney General's Brief") (filed Jan. 5, 2018) at 18.

[79] *Id.* at 19 and 20.

[80] Woolridge Testimony at 5.

rates and capital costs whereas the Attorney General concludes that interest rates and capital costs are at low levels and likely to remain low for some time.[81] The Commission agrees with the Attorney General that, although interest rates are increasing, they are doing so slowly and are still historically low. In fact, the Federal Reserve noted the following:

> The Committee expects that economic conditions will evolve in a manner that will warrant gradual increases in the federal funds rate; the federal funds rate is likely to remain, for some time, below levels that are expected to prevail in the longer run. However, the actual path of the federal funds rate will depend on the economic outlook as informed by incoming data.[82]

The Commission further agrees that models supporting the low interest rate environment should be given more weight than those supporting high interest rate expectations.

The Commission also agrees with the Attorney General that flotation costs should be excluded from the analysis. The Commission believes that flotation costs are accounted for in the current stock prices, as the price includes the underwriting spread and adding the adjustment amounts to double counting. Removal of the flotation costs from Kentucky Power's initial cost of equity range lowers the range to 9.6 percent from 10.8 percent.[83]

The 2017 economic environment has shown signs of relative improvement. In response to low inflation and low unemployment, the Federal Reserve increased interest rates a quarter of a percent three times in 2017. Current outlooks for 2018 are

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[81] *Id.*

[82] Testimony of Richard A. Baudino at 8.

[83] McKenzie Direct Testimony, Exhibit AMM-2 at 1.

healthy, with gross domestic product growth rates expected to remain between two and three percent, unemployment forecasted to continue at the natural rate, and inflation expected to hover at around two percent.[84] However, notwithstanding these improvements, the economy of Eastern Kentucky has lagged behind national and state trends. Employment trends have not recovered to pre-recession levels, earnings trends remain stagnant and lag behind the state trends, and poverty rates in the majority of Kentucky Power's service territory are 24.4 percent or higher.[85]

The Commission is cognizant of the risk inherent to Kentucky Power's service territory and load profile. The Commission notes the Attorney General's position that Eastern Kentucky has been economically depressed for the past decade and that the Commission should consider the economic conditions of the region in evaluating the overall rates and rate design.[86] Therefore, given the adverse economic situation of the service territory of high unemployment, low earnings, and high poverty rates, the Commission finds a lower ROE will allow Kentucky Power to earn a fair return while reflecting the economic situation of its customers.

For 2016, the median ROE of the utilities in the Attorney General's proxy group was 9.3 percent; for Kentucky Power's proxy group, the median ROE was 9.4 percent.[87] In addition, the average authorized ROE reported by SNL Financial for 2017 is

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[84] https://www.thebalance.com/us-economic-outlook-3305669.

[85] Attorney General's Brief at 12; Dismukes Testimony at 5-6; Dec. 6, 2017 H.V.T., PSC Exhibit 1.

[86] Dismukes Testimony at 6.

[87] Woolridge Testimony, Exhibit JRW-4 at 1.

approximately 9.7 percent.[88] The Commission agrees with Kentucky Power that this is a benchmark worthy of consideration, but disagrees that a downward adjustment will be injurious to customers and the Kentucky economy.[89] Based on the entire record developed in this proceeding, we find that an ROE of 9.7 falls within the range of the Attorney General's proposed 8.6 percent to the initial proposed ROE of 10.31 percent, and within Kentucky Power's original range of 9.6-10.8 percent, adjusted for flotation costs. Additionally, an ROE of 9.7 is within the range of the benchmarks provided by SNL, the proxy groups, and recent Commission Orders[90].

Rate-of-Return Summary

Applying the rates of 4.36 percent for long-term debt, 1.25 percent for short-term debt, 1.95 percent for accounts receivable financing, and 9.70 percent for common equity to the Commission adjusted capital structure produces an overall cost of capital of 6.44 percent.[91] The cost of capital produces a return on Kentucky Power's rate base of 6.42 percent.

BASE RATE REVENUE REQUIREMENTS

In the Settlement, Kentucky Power and the Settling Intervenors agreed to a base rate increase of $31.8 million. The Attorney General's expert witness proposed a base

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[88] Direct Testimony and Exhibits of Gregory W. Tillman on behalf of Wal-Mart Stores East, LP and Sam's East, Inc. at 11.

[89] Rebuttal Testimony of Adrien M. McKenzie, CFA at 73.

[90] Case No. 2016-00370 Electronic Application of Kentucky Utilities Company For An Adjustment Of Its Electric Rates and For Certificates of Public Convenience and Necessity (Ky. PSC Jun. 22, 2017) and Case No. 2016-00371 Electronic Application of Louisville Gas and Electric Company For An Adjustment Of Its Electric and Gas Rates and For Certificates Of Public Convenience and Necessity (Ky. PSC Jun. 22, 2017).

rate increase of $39.8 million. The Commission finds that, subject to the adjustments discussed in this Order, a base rate increase of $12.35 million is reasonable, as is discussed in the Total Jurisdictional Revenue Requirement section below.

REVENUE REQUIREMENT-RELATED RIDERS AND DEFERRALS

Big Sandy Retirement Rider

In its Application, Kentucky Power proposed to rename the Big Sandy Retirement Rider to the Decommissioning Rider to alleviate customer confusion regarding the purpose of the rider. Pursuant to the settlement agreement approved in Case No. 2014-00396, Kentucky Power recovers the coal-related retirement costs of Big Sandy Unit 1, the retirement costs of Big Sandy Unit 2, and other site-related retirement costs through this rider. Only the rider name will change; the rider will continue to operate in the manner approved by the Commission in Case No. 2014-00396.

The Commission finds the name change reasonable and that it should be approved. The Commission further finds that the carrying charges associated with this rider should be based on the weighted average cost of capital ("WACC"), after reflecting the impacts of the reduction in the federal corporate income tax rates approved in this Order, should become effective as of the date of this Order. However, the monthly amounts collected will not change until Kentucky Power makes its annual filing on or before August 15, 2018, to adjust the amounts collected under this rider.

Big Sandy Unit 1 Operation Rider

In its Application, Kentucky Power proposed to eliminate the Big Sandy Unit 1 Operation Rider ("Tariff B.S.1.O.R.") and to recover through base rates the costs

[91] The Commission adjusted capital structure consists of 54.45 percent long-term debt, 3.2

currently recovered through Tariff B.S.1.O.R. Once new rates become effective in this case, Tariff B.S.1.O.R. will have an under- or over-recovery balance. Therefore, Kentucky Power also requested authority to establish a regulatory asset or liability that will allow Kentucky Power to track and defer any under- or over-recovery balance until its next rate case.

In Case No. 2014-00396, the Commission approved Tariff B.S.1.O.R. to permit Kentucky Power to recover the non-fuel costs of operating Big Sandy Unit 1 as a coal burning unit until its conversion to natural gas, the non-fuel costs of its operation as a natural gas unit and capital investment required for its conversion to natural gas once it is placed in service. Tariff B.S.1.O.R. was designed to be in effect until the rates established in Kentucky Power's next base rate case were implemented.

The Commission has previously approved regulatory assets for other jurisdictional utilities. Such approval has been granted when a utility has incurred: (1) an extraordinary, nonrecurring expense which could not have reasonably been anticipated or included in the utility's planning; (2) an expense resulting from a statutory or administrative directive; (3) an expense in relation to an industry-sponsored initiative; or (4) an extraordinary or nonrecurring expense that over time will result in a saving that fully offsets the cost.[92] Since Tariff B.S.1.O.R. was approved by the Commission in Case No. 2014-00396, the establishment of a regulatory asset to address the under-

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percent of short term debt, 1.67 percent of accounts receivable financing, and 41.68 percent of common equity.

[92] Case No. 2008-00436, *The Application of East Kentucky Power Cooperative, Inc. for an Order Approving Accounting Practices to Establish a Regulatory Asset Related to Certain Replacement Power Costs Resulting from Generation Forced Outages* (Ky. PSC Dec. 23, 2008), at 4. *See also* Case No. 2010-00449, *Application of East Kentucky Power Cooperative, Inc. for an Order Approving the Establishment of a Regulatory Asset for the Amount Expended on Its Smith 1 Generating Unit* (Ky. PSC Feb, 28, 2011), at 7.

recovery of Tariff B.S.1.O.R. is consistent with the second example listed above. Regarding a possible regulatory liability, the Commission notes that it is appropriate that Kentucky Power customers be the beneficiaries of any over-recovery of Tariff B.S.1.O.R.

The Commission finds the establishment of a regulatory asset or liability due to the elimination of Tariff B.S.1.O.R. to be reasonable and that it should be approved. This approval is for accounting purposes only, and the appropriate ratemaking treatment for the regulatory asset or liability account will be addressed in Kentucky Power's next general rate case.

Tariff A.T.R.

In its Application, Kentucky Power proposed to eliminate Tariff Asset Transfer Rider ("Tariff A.T.R."). Given that Kentucky Power has recovered the full amount that Tariff A.T.R. was designed to recover, the Commission finds the elimination of Tariff A.T.R. to be reasonable and that it should be approved.

Tariff K.E.D.S.

In its Application, Kentucky Power proposed to increase Tariff K.E.D.S. from $0.15 per meter per month to $0.25 per meter per month. In the Settlement, Kentucky Power and the Settling Intervenors agreed to a surcharge of $0.10 per meter for residential customers and $1.00 per meter for non-residential customers. KCUC did not provide testimony regarding Tariff K.E.D.S.

Tariff K.E.D.S. imposes an economic development surcharge, which was approved in Kentucky Power's last rate case,[93] to fund economic development initiatives

[93] Case No. 2014-00396, Final Order at 49-51.

in Kentucky Power's service territory, with funds collected through the surcharge matched equally by Kentucky Power from AEP shareholder funds. As a basis for the increase, Kentucky Power argued that additional economic development funds were needed to grow its load and customer base. One of the reasons for Kentucky Power's proposed rate increase is a significant decline in load and customers since the economic downturn in 2008.[94] A decrease in customers and load concentrates costs among a smaller customer base, which results in fewer customers paying a larger share of the cost. Correspondingly, a growth in load and customer base spreads costs among a greater number of customers.

The Attorney General recommended that the economic development surcharge be eliminated.[95] The Attorney General asserted that Kentucky Power failed to provide evidence of a direct tie between Kentucky Power's economic development efforts and increased jobs and electricity sales.[96] The Attorney General further asserted that the economic development surcharge simply redistributes ratepayer dollars without evidence of an identifiable benefit for ratepayers.

In rebuttal, Kentucky Power countered that it maintains economic development metrics, including job counts, investments, and grants, which it uses to evaluate the

[94] Application, Direct Testimony of Brad N. Hall ("Hall Direct Testimony") at 5. Between 2008 and 2016, Kentucky Power lost 6,931 customers, and its total annual sales declined from 7.24 GWh to 5.80 GWh.

[95] Direct Testimony of David E. Dismukes ("Dismukes Testimony") at 4; Direct Testimony of Roger McCann ("McCann Testimony") at 6, 17.

[96] Dismukes Testimony at 4, 41.

success of its economic development program.[97] In a subsequent discovery response, Kentucky Power provided its written economic development action plan with strategic goals and metrics set forth in specific detail.[98] Kentucky Power contended that its economic development program achieves identifiable goals, and that Kentucky Power's customers receive benefits from the economic development surcharge. As an example, Kentucky Power asserted that its economic development efforts are projected to create 1,705 new full-time positions, with an additional 1,000 construction jobs.[99]

The Commission recognizes the importance of economic development efforts, especially given the economic needs of Kentucky Power's service area. However, the Commission also recognizes that 26 percent, or 35,756, of Kentucky Power's residential customers are at or below the poverty level.[100] In 2016, Kentucky Power disconnected more than 11,000 residential customers who could not pay their electric bill.[101] In the course of this proceeding, the Commission received a large number of public comments from residential customers who questioned why they are charged for Kentucky Power's economic development efforts, particularly given the difficulty that residential customers have in paying their electric bills. Residential customers, especially those on fixed incomes, cannot pass along their costs; to a certain extent, non-residential customers

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[97] Dec. 8, 2017 H.V.T. at 10:44:56.

[98] Kentucky Power Response to KCUC's Post Hearing Data Request ("Response to KCUC Post Hearing Request"), Item No. 1, Attachment 1.

[99] Hall Direct Testimony at 12; Dec. 8, 2017 H.V.T. at 10:31:23. On December 7, 2017, there was an announcement that 875 jobs would result from a business locating in Pikeville, Kentucky. Prior to that announcement, there were 830 projected new jobs created from Kentucky Power economic development efforts.

[100] Dec. 8, 2017 H.V.T. at 11:58:01 and 5:33:49.

[101] *Id.* at 11:58:19.

can pass along their costs to their customers. The Commission finds that the residential customer economic development surcharge of $0.10 per meter per month, as set forth in the Settlement, is unreasonable and therefore should be denied. The Commission further finds that the residential customer economic development surcharge should be eliminated. However, the Commission finds that the economic development surcharge on non-residential customers of $1.00 per meter per month, as set forth in the Settlement, is reasonable. Therefore, the Commission approves the portion of the Settlement applicable to the economic development surcharge for non-residential customers only.

Home Energy Assistance Program Surcharge

In its Application, Kentucky Power proposed to increase the HEAP surcharge from $0.15 per residential meter per month to $0.20 per residential meter per month. Similar to the economic development surcharge, funds collected through the HEAP surcharge are matched equally by Kentucky Power from AEP shareholder funds.

HEAP funds provide subsidies to assist eligible low-income customers in Kentucky Power's service territory to pay electric bills during seven peak heating and cooling months.[102] There is a waiting list of eligible customers because there are not sufficient HEAP funds available to assist all eligible customers.[103]

The Attorney General supported the five-cent increase to $0.20 per residential meter per month, but argued that the increase was inadequate to keep pace with

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[102] McCann Testimony at 5-6, 14. Subsidies are available in January, February, March, July, August, September, and December.

[103] *Id.* at 15. As of Sept. 20, 2017, there were 1,475 eligible customers on a wait-list for HEAP subsidies.

Kentucky Power's rate increases. The Attorney General proposed that the Commission approve the HEAP surcharge increase and, if the Commission discontinued the economic development surcharge, that the HEAP surcharge be increased in the same amount by which the economic development is reduced.[104]

Kentucky Power's President, Matthew J. Satterwhite, testified that, if the Commission modified the Settlement to eliminate the $0.10 per meter per month economic development surcharge for residential customers, Kentucky Power could agree to a commensurate increase in the HEAP surcharge by $0.10 per residential meter per month, with matching shareholder funds.[105]

The Settlement is silent as to the HEAP surcharge.

The Commission finds that the proposed increase in the HEAP surcharge is insufficient to address the demonstrable need to assist eligible low-income customers with their electric bills. The Commission further finds that the HEAP surcharge should be increased by the corresponding amount that the economic development surcharge for residential customers is reduced. Therefore, the Commission rejects Kentucky Power's proposed increase in the HEAP surcharge to $0.20 per residential meter per month. The Commission finds an increase of the HEAP surcharge to $0.30 per residential meter per month is reasonable and should be approved.

Rockport Deferral Mechanism

In the Settlement, Kentucky Power and the Settling Intervenors agreed to defer $50 million of non-fuel and non-environmental lease expenses from Rockport Unit 2

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[104] McCann Testimony at 6, 17; Dismukes Testimony at 4.

over five years, with the establishment of a regulatory asset for later recovery ("Rockport Deferral Regulatory Asset") of these expenses. This Rockport Deferral Regulatory Asset, plus a carrying charge based on a WACC of 9.11 percent, will be recovered through Kentucky Power's Tariff P.P.A. over five-years starting in December of 2022. The dates of the end of the deferral period and the start of the five-year amortization period coincide with the anticipated end of the Rockport UPA lease agreement.[106]

The Settlement proposed a deferral of $15 million in 2018 and 2019, $10 million in 2020, and $5 million in 2021 and 2022. The Settlement's annual revenue requirement reflects a decrease to base rates of the 2018 $15 million adjustment. In 2020, 2021 and 2022 the decrease in the deferral will be offset with an increase in the amount recovered through Tariff P.P.A. Additionally, in 2022, the increase in the amount recovered through Tariff P.P.A. will be prorated through December 8, 2022, as the Rockport UPA will terminate on that date. By utilizing Tariff P.P.A., Kentucky Power is able to reduce the annual deferral amount and concurrently keep base rates unchanged. Beginning in December 2022, the five-year deferral period will end and the recovery of the Rockport Deferral Regulatory Asset will begin. The Rockport Deferral Regulatory Asset will be amortized through 2027 and be subject to carrying charges until it is fully recovered. Kentucky Power estimates that the Rockport Deferral

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[105] Dec. 7, 2017 H.V.T. at 10:53:09.

[106] Satterwhite Settlement Testimony at S-10.

Regulatory Asset will total approximately $59 million in December 2022. That amount will decrease incrementally until fully collected over the five-year amortization period.[107]

Neither the Attorney General nor KCUC offered testimony concerning the Rockport Deferral. However, during the hearing and in his post-hearing brief, the Attorney General expressed his concerns about the "very large financing costs" associated with the deferrals, stating that the "$50M over the entire deferral period is going to have financing costs piled on top of it… [t]hese financing costs are at the weighted average cost of capital including the 9.75 percent return of equity which then gets a tax gross up on top of it."[108] The Attorney General further stated that a concern that the costs of the deferral will eventually require rate recovery in future rate proceedings.[109] The Attorney General recommended that the carrying charge be reduced to 4.36 percent for Kentucky Power's current long term debt.[110]

In response, Kentucky Power argued that the 9.11 percent WACC made Kentucky Power financially whole because of its need to finance the deferral through a combination of debt and equity, and therefore was appropriate.[111]

The recovery period of the proposed Rockport Deferral Mechanism is contingent upon Kentucky Power not renewing the Rockport UPA.[112] If the lease is not renewed,

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[107] *See* Appendix A, paragraph 3 for details of the Rockport UPA Expense Deferral.

[108] Dec. 6, 2017 H.V.T. at 04:01:19; *See also* Attorney General's Brief at 31.

[109] Dec. 6, 2017 H.V.T. at 04:01:19

[110] Attorney General's Brief at 31.

[111] Kentucky Power's Post Hearing Brief ("Kentucky Power's Brief") (filed Jan. 5, 2018) at 48.

[112] Kentucky Power stated that it is unlikely that the Rockport lease will be renewed. Dec. 6, 2017 H.V.T. at 5:47:44; Kentucky Power Response to Staff's Second Request, Item 72.

the expenses associated with the Rockport UPA will be removed from rate base, which allows the regulatory asset to be funded without a change in rate base. However, if the lease is renewed, the deferred expenses will have to be recovered from future ratepayers, and possibly through an increase in rate base.[113] The Commission recognizes that there are inherent risks associated with any deferral mechanism, especially since the deferral recovery is contingent upon not renewing the Rockport UPA. Given Kentucky Power's excess capacity and slow load growth, the Commission believes the benefits of the deferral outweigh the associated risks, and approves the Rockport Deferral Mechanism and the associated $15 million decrease to rate base. The carrying charges associated with this rider shall be based on the WACC approved in this Order and are effective as of the date of this Order. This approval is for accounting purposes only, and the appropriate ratemaking treatment for this regulatory asset account will be addressed in Kentucky Power's next general rate case.

Environmental Surcharge Tariff E.S.

Kentucky Power proposed an addition to its Environmental Compliance Plan to recover the cost of installing Selective Catalytic Reduction ("SCR") technology at Rockport Unit 1, affecting the amounts collected under Tariff E.S The project is discussed later in the Environmental Compliance Plan section of this Order. Kentucky Power estimated the revenue requirement for the SCR project to be $3,903,065.[114] The Commission finds the Rockport Unit 1 revenue requirement to be reasonable.

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[113] Satterwhite Settlement Testimony at S-13.

[114] Elliott Testimony, Exhibit AJE-5.

TOTAL JURISDICTIONAL REVENUE REQUIREMENTS

The Commission has found that Kentucky Power's required ROE falls within a range of 8.60 percent to 10.31 percent, and approves an ROE of 9.70 percent. The Settlement proposed a base rate increase of $31.8 million and environmental surcharge revenues of $3.9 million, for a total of $35.7 million. The environmental surcharge is discussed farther below. Because Kentucky Power recovers the costs associated with the decommissioning of coal-related assets at Big Sandy through the Decommissioning Rider, those costs are not included for recovery in the base rates. However, for the twelve months ending September 30, 2018, Kentucky Power will recover approximately $20.2 million through the Decommissioning Rider,

Due to the modifications the Commission makes to the Settlement and the provision for the reduction in the federal corporate income tax rate from 35 percent to 21 percent in the Tax Cuts and Jobs Act, the Commission finds that an increase in base rate revenues of $12.35 million, as shown in Appendix F to this Order, exclusive of the environmental surcharge, will result in fair, just, and reasonable electric rates for Kentucky Power and its ratepayers. The Commission utilized Kentucky Power's equity gross up revenue conversion factor ("GRCF"), as provided in Kentucky Power's revised Environmental Surcharge forms filed on January 3, 2018, to reflect the reduction in the federal corporation income tax rate effective with the date of this Order. Additionally, the adjustments the Commission makes to the test year operating income and expense items reflect the income tax rate reduction and change in the GRCF. The excess accumulated deferred income tax ("ADIT") impacts resulting from the reduction federal corporate income tax rate will be addressed in Case No. 2017-00477. The Commission also finds that Kentucky Power should establish a mechanism to track the over/under-collection of federal income taxes, and that a true-up of any over/under-collections be addressed in Case No. 2017-00477.

Due to the economic conditions in Kentucky Power's service territory, the Commission believes that the impact of the federal corporate income tax reduction on rates should be put into place effective with the date of this Order. In addition, the lower rates should serve as an impetus for economic development through recruiting new businesses as well as maintaining existing business customers.

NONREVENUE REQUIREMENT RIDERS AND TARIFFS

The following sections address riders and a tariff that have no direct impact on Kentucky Power's revenue requirement. The discussion covers both those that have been contested, and those that are included in the Settlement.

Non-Utility Generator Tariff

In its Application, Kentucky Power proposed to revise the Non-Utility Generator Tariff ("Tariff N.U.G.") to eliminate a provision that requires a 30-day written notice to customers taking service under Tariff N.U.G. if a transmission provider implements charges for transmission congestion. Kentucky Power asserted that this clause is no longer necessary because PJM has already created transmission congestion charges.[115] Kentucky Power also proposed to revise language in the special terms and conditions section of Tariff N.U.G. to clarify the requirement to take service for remote

[115] Application, Vaughan Direct Testimony at 25.

self-supply.[116] The Settlement is silent as to Tariff N.U.G. Neither KCUC nor the Attorney General contested the proposed revisions to Tariff N.U.G.

The Commission finds the revisions to Tariff N.U.G. to be reasonable and that they should be approved.

Systems Sales Clause

In its Application, Kentucky Power proposed to reduce monthly bill volatility by revising its Tariff S.S.C. to change from a monthly system sales adjustment factor to an annual sales adjustment factor. Kentucky Power further proposed to set the Tariff S.S.C. rate to $0, with the difference between actual off-system sales margins and a base amount of $7,163,948 deferred based on the current 75/25 customer sharing mechanism approved in Case No. 2014-00396.[117] The net deferred credit or charge to customers would then be the base for the annual Tariff S.S.C. rate update.[118] Kentucky Power proposed to file the required true-up information no later than August 15 of each year, with rates to be effective with Cycle 1 of October. The first filing would be made by August 15, 2018. The Settlement is silent as to Tariff S.S.C. Neither the Attorney General nor KCUC contested the proposed revisions to Tariff S.S.C.

The Commission finds the revisions to Tariff S.S.C., as adjusted to include $7,650,350 in base rates, to be reasonable and should be approved.

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[116] Sharp Direct Testimony at 28.

[117] Kentucky Power credits 75 percent of the difference between base and actual off system sales margins amounts to customers and retains 25 percent.

[118] Vaughan Direct Testimony at 36-37.

PJM Billing Line Items

In the Application, Kentucky Power proposed to include additional PJM Billing Line Items ("BLIs") for recovery through its FAC. Kentucky Power stated that these BLIs represent items that either require generation resources to be running and online, or are associated with other BLIs that require generation resources to be running and online. Kentucky Power stated that all of the service functions represented by the BLIs are related to fuel-related services previously received by Kentucky Power when it was a member of the AEP East Pool, and that those amounts were previously included in Kentucky Power's base fuel cost. The Settlement is silent as to the BLIs. Neither the Attorney General nor KCUC contested this proposal.

The Commission has reviewed the additional BLIs and finds that they are appropriate for inclusion in the FAC, as these BLIs represent charges and credits that relate to fuel consumed by resources that are running and online. Furthermore, the Commission finds that when Kentucky Power files its compliance tariff, it should amend its Tariff F.A.C to include PJM BLIs 2211, 2215, and 2415, as those BLIs have replaced BLI 2210.

MODIFICATIONS TO TERMS AND CONDITIONS OF SERVICE TARIFFS

In its Application, Kentucky Power proposed certain revisions to its terms and conditions for service. The revisions include: verification of a customer's identity and proof of ownership or lease of property where service is requested at the time an application for service is filed; information to be considered when evaluating whether to waive a deposit; payment arrangements; mobile alerts; elimination of the employee discount; modifying the equal payment plan; and denial or discontinuance of service.

Kentucky Power also requested a deviation from 807 KAR 5:006, Section 14(2)(a) to amend when a customer can sign up for the Equal Payment Plan, and the annual settle-up month for certain customers.

Neither the Attorney General nor KCUC contested the revisions.

The Commission finds that the proposed revisions to the terms and conditions of service as contained in the Application are reasonable, with the exception of the denial or discontinuance of service, and should be approved. The Commission further finds that Kentucky Power established good cause to deviate from 807 KAR 5:006, Section 14(2)(a), and that its request for a deviation should be granted.

As to the denial or discontinuance of service, the Commission finds that the proposed revisions as contained in the Application are overbroad and do not comply with Commission precedent.[119] In response to Commission Staff's Post Hearing Data Request, Kentucky Power revised the terms for denial or discontinuance of service as follows:

> The Company reserves the right to refuse or discontinue service to any customer if the customer is indebted to the Company for any service theretofore rendered at any location. Service will not be supplied or continued to any premises if at the time of application for service the Applicant is merely acting as an agent of a person or former customer who is indebted to the Company for service previously supplied at the same, or other premises, until payment of such indebtedness shall have been made;

The Commission finds that the revised language regarding denial or discontinuance of service as filed on in the Supplemental Response on December 21, 2017, is reasonable and should be approved.

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[119] *See* H.V.T., PSC Exhibits 2, 3, 4, and 6.

RATE DESIGN, TARIFFS AND OTHER ISSUES

Rate Design

Kentucky Power filed a fully allocated jurisdictional cost-of-service study ("COSS") to determine the cost to service each customer class as well as the rate of return on rate base for each class during the test year. The results of the COSS illustrate the amount of cross-subsidization between the rate classes and show that all non-residential rate classes subsidize the residential class. In its Application, Kentucky Power proposed to reduce these subsidies by five percent in its proposed rates. The Settlement modifies this proposed revenue allocation and proposes to use the first $5.8 million of any Commission-authorized revenue increase to the Industrial General Service ("IGS") rate class to fully eliminate the subsidy Rate IGS would have paid under the rate increase as originally proposed by Kentucky Power.[120] The remaining revenue increase is spread uniformly among the rate classes, further reducing interclass subsides.[121]

The Attorney General did not offer any testimony concerning the allocation of any proposed revenue increase, aside from recommending limiting any revenue increase, and stating that Kentucky Power's customers are unable to afford a rate increase and that a large increase would set the entire economy of Eastern Kentucky back, counteracting any economic expansion.[122]

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[120] Satterwhite Settlement Testimony at S-9; Dec. 8, 2017 H.V.T. at 2:59:20; Direct Testimony of Stephen J. Baron ("Baron Testimony") at 15 and Table 2.

[121] Satterwhite Settlement Testimony at S-9.

[122] Dismukes Testimony at 3.

The KCUC does not support the revenue allocation as set forth in the Settlement, contending that the Settlement does not provide fair or reasonable treatment of the Tariff L.G.S. customer class. KCUC stated that in addition to bearing a subsidy burden associated with the overall rate structure, the L.G.S. class must also absorb an additional $500,000 subsidy resulting from the Public and Private School service ("PS") tariff.[123] To remedy this, the KCUC proposes that the first $500,000 of any additional Commission-directed decrease in the revenue requirement be applied to the Tariff L.G.S. customer class and any revenue reduction beyond $500,000 be uniformly spread among all the rate classes in proportion to each class's revenue requirement.[124]

Residential Customer Charge

In its Application, Kentucky Power proposed an increase in the residential customer charge from $11.00 to $17.50, an increase of 59 percent. The cost-of-service study filed by Kentucky Power in this proceeding supports a customer charge of $37.88.[125] The Settlement allows for an increase in the residential customer charge to $14.00, an increase of 27 percent.

The Attorney General objected to any increase on the residential customer charge.[126] The Attorney General contended that shifts towards fixed cost recovery disproportionally hurt low-income customers and Kentucky Power did not provide

[123] Settlement Testimony of Kevin Higgins ("Higgins Settlement Testimony") at 2.

[124] *Id.* at 4.

[125] Vaughan Direct Testimony, Exhibit AEV-2 at 1.

[126] Dismukes Testimony at 6.

sufficient evidence to justify an increase.[127] The Attorney General argued that Kentucky Power's fixed cost calculation of almost $38.00 is flawed because a portion of demand-related costs are assigned as fixed costs, which the Attorney General argued is fundamentally incorrect.[128] The Attorney General noted that none of the parties to the proposed Settlement represent the interests of residential ratepayers, and the proposed $14 would recover too much of any potential revenue increase through the customer charge and undermine future incentives for efficiency, resulting in an erosion of LIHEAP funds.[129]

The Commission believes an increase to the Residential Basic Service Charge is warranted, and finds that the Settlement's increase to $14.00 is reasonable. The proposed 27 percent increase is consistent with the principle of gradualism that the Commission has long employed. Consistent with this change, the Commission also approves the customer charges of $14.00 as set forth in the Settlement for the three optional residential tariffs: 1) Residential Service Load Management Time-of-Day; 2) Residential Service Time-of-Day; 3) and Experimental Residential Service Time-of-Day 2. The Commission also approves a customer charge of $14.50 for the new optional Residential Demand Metered Electric Service ("Tariff R.S.D.").[130]

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[127] *Id.*

[128] *Id.* at 20.

[129] Attorney General's Brief at 32-33.

[130] The Settlement and supporting testimony state that Kentucky Power and the Settling Intervenors agreed to a residential customer charge of $14.00. Settlement at paragraph 16(a); Satterwhite Settlement Testimony at S-22. The proposed Settlement Tariff R.S.D. filed on Dec. 1, 2017, inadvertently contains a monthly customer charge of $17.50.

General Service Rate Class

Kentucky Power proposed to combine the Small General Service ("S.G.S.") and Medium General Service ("M.G.S.") rate classes into a single General Service ("G.S.") rate class under which all general service customers with average demands up to 100 kilowatts ("kW") will take service. Kentucky Power stated that both the S.G.S. and M.G.S. rate classes currently incur a monthly service charge and a blocked energy charge. Additionally, the M.G.S. rate class incurs a demand charge. Due to this current tariff structure, there is movement between the S.G.S. and M.G.S. rate classes as load characteristics vary month to month for many commercial customers. Kentucky Power stated that combining the S.G.S. and M.G.S. into a single tariff allows for administration efficiencies by eliminating this movement between the two rate classes.[131] The new G.S. tariff combines rate design features from the S.G.S. and M.G.S. tariffs, and will include a monthly service charge, two blocked energy charges, and a demand charge for monthly billing demand greater than 10 kW. The blocked energy charge transition point is 4,450 kilowatt hours ("kWh"). Kentucky Power stated that setting the kWh block at 4,450 kWh ensures that almost all usage that was billed under the current S.G.S. tariff will continue to be billed on an energy charge only and such a rate design will minimize bill impact on current S.G.S. and M.G.S. customers.[132]

Although the proposed rate design minimizes the impact on an average commercial customer, due to the proposed increase in the demand charge from $1.91

[131] Vaughan Direct Testimony at 21.

[132] *Id.* at 21.

for all kW to $7.95 for all kW greater than 10 kW, it negatively affects customers whose load characteristics include low usage coupled with high demand.[133] The Commission believes that Kentucky Power's proposed increase in the demand charge of over 300 percent is excessive. For this reason, the Commission will minimize the impact on high demand commercial customers, apply a 2-step phase-in increase of demand rates, and limit the increase in year 2 to $6.00 per kW. In addition, Kentucky Power must identify and contact G.S. class customers whose average monthly demand is 25 kW or greater to meet to discuss the impacts of the rate increase on those customers' bills and analyze other tariff options, such as time-of-day rates, that may offer relief to these customers. Last, Kentucky Power should file with the Commission, within twelve months of this Order, a report listing the commercial customers who meet this load profile and the results of each meeting.

Rate Adjustment

In setting the rates shown in Appendix C, the Commission maintained the basic service charge for each class that was included in the Settlement. The reduction of Kentucky Power's revenue increase was allocated to the energy charges of those customer classes for which revenue increases were proposed. The reduction to each class's proposed revenue increase was approximately in proportion to the increase set forth in the Settlement.

[133] Dec. 8, 2017 H.V.T. at 4:53:40.

Tariff Purchased Power Adjustment

In its Application, Kentucky Power proposed to include the following additional cost of service items to be tracked and recovered through Tariff P.P.A.: (1) PJM OATT charges and credits that it incurs or receives from its participation as a LSE in the organized wholesale power markets of PJM; (2) purchased power costs excluded from recovery through the FAC as a result of the purchased power limitation; and (3) gains and losses from incidental gas sales. In addition, Kentucky Power proposed to change Tariff P.P.A. from a monthly adjusting surcharge to an annually updated surcharge.

The Attorney General filed testimony stating that these cost-of-service items should continue to be collected through base rates as Kentucky Power has not demonstrated a compelling reason to have these items tracked and recovered through Tariff P.P.A.[134]

1. PJM LSE OATT Charges and Credits

Kentucky Power proposed to include the following PJM LSE transmission charges and credits to costs recoverable through Tariff P.P.A.: network integration transmission service ("NITS"); transmission owner scheduling system control and dispatch service ("TO"); regional transmission expansion plan ("RTEP"); point-to-point transmission service; and RTO start-up cost recovery. An adjusted level of the net OATT charges and credits in the amount of $74,377,364 will be included in base rates.[135] The amount above or below the base rate level would be tracked monthly and the annual net over- or under-collection would then be collected from or credited to customers through the operation of Tariff P.P.A.

[134] Smith Testimony at 70.

Kentucky Power stated that the proposed tracking mechanism for PJM OATT LSE Charges is necessary due to the volatility of these PJM charges and credits, which Kentucky Power claimed are largely out of its control. Kentucky Power estimated that its PJM OATT LSE expenses will increase in 2018 by approximately $14 million, or 19 percent over the test year amount.[136] Kentucky Power expects increasing investment in the transmission grid by PJM member transmission owners, which will increase transmission charges allocated to LSEs in PJM. Kentucky Power stated that tracking the PJM LSE charges and credits via Tariff P.P.A. could preclude it from seeking more frequent rate cases.[137]

Finally, two proceedings currently before the FERC may affect the level of PJM LSE OATT charges incurred by Kentucky Power. One proceeding is a challenge to the ROE included in the AEP Zone formula, which determines the PJM transmission costs of service for the AEP Transmission Zone. Kentucky Power stated that at this time, any change resulting from this proceeding is not known and measurable. Therefore, an adjustment in this case is not possible. The second proceeding is a pending non-unanimous settlement regarding the cost allocation methodology historically used by PJM to allocate costs of transmission enhancement projects to the LSEs in its footprint. If approved, the proposed stipulation is expected to result in lower PJM LSE OATT

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[135] Vaughan Direct Testimony at 29.

[136] Satterwhite Settlement Testimony at S-14–S-15.

[137] Vaughan Direct Testimony at 27-28.

charges. However, the timing or magnitude of the possible cost allocation changes are not currently known.[138]

The Settlement revised the proposal regarding the PJM OATT LSE charges and credits as follows:

- Kentucky Power will recover and collect 80 percent of the annual over- or under-collection of PJM OATT LSE charges, as compared to the annual amount included in base rates, ("Annual PJM OATT LSE Recovery") through Tariff P.P.A.
- Kentucky Power will credit against the Annual PJM OATT LSE Recovery 100 percent of the difference between the return on its incremental transmission investments calculated using the FERC approved PJM OATT return on equity, and the return on its incremental transmission investments calculated using the 9.75 percent return on equity provided for in the settlement.
- The changes to Tariff P.P.A. to allow for the Annual PJM OATT LSE Recovery will terminate on the effective date when base rates are reset in the next base rate proceeding unless otherwise extended by the Commission.

Due to the volatility of the OATT charges and credits, the Commission finds the proposal to include the PJM LSE transmission charges and credits to the costs recoverable through Tariff P.P.A., as modified in the Settlement, reasonable with one modification. When calculating the credit against the Annual PJM OATT LSE Recovery, the return on equity amounts used to calculate the incremental transmission investments shall be 9.7 percent, the Commission-approved ROE amount.

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[138] *Id.* at 28-29.

In conjunction with approving the PJM OATT LSE tracker, the Commission finds that the three-year stay-out provision in the Settlement is reasonable and should be accepted. In approving the tracker, the Commission addresses Kentucky Power's primary concern, raised in the last rate case and in this case, that an increase in major expenses not directly under Kentucky Power's control would result in more frequent rate cases.

Regarding proposed transmission projects at PJM, the Commission expects Kentucky Power to work through the PJM stakeholder process to protect its customer interests.

2. <u>FAC Purchased Power Limitations.</u>

Kentucky Power proposed to track, on a monthly basis, the amount of purchased power costs excluded for recovery through the FAC over or above the base rate level using deferral accounting. The annual net over- or under-collection of these purchase power costs would be collected from or credited to customers through Tariff P.P.A.[139]

The FAC Purchase Power Limitation is a calculation that caps the amount of purchase power expense to be recovered through the monthly FAC surcharge. The calculation compares the cost of actual purchased power on an hourly basis to the cost of Kentucky Power's highest cost unit or the theoretical peaking unit equivalent, and caps the FAC-recoverable purchase power expense at the cost ($/MWh) of the highest generating unit (Kentucky Power owned or peaking unit equivalent). Kentucky Power claims that, because it relies on factors outside of its control, the FAC Purchase Power Limitation and the peaking unit equivalent calculation promote variability and volatility.

[139] *Id.* at 29.

The Commission is not convinced that this issue requires special ratemaking treatment. The Commission has long held that any purchased power costs not recoverable through the FAC are eligible for recovery through base rates. The Commission finds Kentucky Power's proposal to include an estimated amount of FAC Purchased Power Limitation Expense in base rates, and to subsequently true up that amount through Tariff P.P.A., is unreasonable, and therefore should be denied. The Commission notes that Kentucky Power filed this case using a historic test period. The Commission will allow recovery of the test year amount of purchased power reasonably incurred, but excluded from the FAC. To the extent that Kentucky Power incurs any expense due to purchased power that is appropriately incurred after the test year, but excluded from the FAC, it can file a base rate case seeking recovery of those expenses. For the foregoing reasons, adjustments W26 and W27, which total $4,032,786, are unreasonable and should be removed from the revenue requirement.

3. Peaking Unit Equivalent Calculation

Kentucky Power proposed to change the methodology for calculating the peaking unit equivalent ("PUE") used in determining the FAC Purchased Power Limitation. In its Application, Kentucky Power proposes to include the cost of firm gas service as an expense in the calculation of its PUE. Kentucky Power stated that since the hypothetical combustion turbine ("CT") could be dispatched any day of the year, it requires firm gas service. The Commission disagrees. While firm gas service would certainly allow the CT to be dispatched any day of the year, the Commission is unaware of any jurisdictional utility utilizing firm gas service for a CT. Because CTs typically operate at low capacity factors and are primarily utilized during the summer peaking months, when pipeline capacity would typically not be constrained, the Commission finds the inclusion of firm gas service in the calculation of the PUE to be unreasonable, and therefore, this change in the PUE calculation should be denied. Kentucky Power's proposal to include startup costs and variable O&M expense is reasonable and should be approved.

4. Gains and Losses from Incidental Gas Sales.

Kentucky Power proposed to recover gains and losses from incidental sales of natural gas through Tariff P.P.A. Kentucky Power nominates Big Sandy Unit 1 in the PJM day-ahead electric power market based in part on the price of natural gas purchased for delivery the next day. If the Big Sandy Unit 1 Day Ahead nomination price is higher than the PJM electric power market clearing price, Big Sandy Unit 1 is not selected to run in the Real Time Market. In such a case, the natural gas purchased must either be stored by Columbia Gas or be sold. Kentucky Power stated that in August, September, and November of 2016, there were days that it was required to sell natural gas that had been purchased for delivery because Big Sandy Unit 1 was not selected by PJM to run.[140]

In Case No. 2014-00078, Duke Energy Kentucky ("Duke Energy") proposed similar treatment of gains and losses it experienced in January and February of 2014 from incidental sales of natural gas.[141] Duke Energy amended its request to apply to similar losses or gains occurring in the future. The Commission approved the treatment of the January and February 2014 gains and losses. However, the Commission found

[140] Application, Direct Testimony of John A. Rogness at 26-27

[141] Case No. 2014-00078, *An Investigation of Duke Energy Kentucky, Inc.'s Accounting Sale of Natural Gas Not Used in Its Combustion Turbines* (Ky. PSC Nov. 25, 2014).

Duke Energy's proposal to apply such treatment to similar losses or gains in the future to be overly broad and did not approve such treatment, finding that such gains and losses should be investigated on a case-by-case basis.

In this case, the Commission finds, as it did in Case No. 2014-00078, that gains and losses from the incidental sale of natural gas should be investigated on a case-by-case basis. If such gains or losses occur in the future, Kentucky Power should notify the Commission so those matters may be addressed in a formal proceeding. For purposes of this case, the Commission finds that the gain on the incidental sale of natural gas of $13,982 should be utilized to reduce Kentucky Power's revenue requirement.

Tariff K-12 School

In its Application, Kentucky Power proposed to discontinue the pilot Tariff K-12 School under which public schools in Kentucky Power's service territory took service under discounted rates. Kentucky Power stated that its load research and class cost of service study demonstrated that Tariff K-12 School customers would be better off in the Tariff L.G.S. customer class than they were previously a part of prior to the pilot Tariff K-12.

Tariff Pilot K-12 School was approved as part of the settlement agreement in Case No. 2014-00396. In Case No. 2014-00396, KSBA argued, as it does in this proceeding, that public school load characteristics were sufficiently unique to justify a distinct rate class for K-12 schools. Because school load data did not exist, Kentucky Power agreed to establish a pilot tariff with load research meters at 30 K-12 schools.

Kentucky Power further agreed to evaluate whether to continue Tariff K-12 School in its next base rate case using the load research data.

Tariff K-12 School rates were designed to produce an annual revenue requirement that was $500,000 less than would be produced under the L.G.S. rates from customers eligible to take service under Tariff K-12 School.[142] Tariff L.G.S. and Tariff M.G.S. customers rates were designed to include the $500,000 subsidy to Tariff K-12 Schools.[143]

Under the Settlement, Tariff K-12 School would cease to be a pilot, and would continue as a separate rate class. The tariff would be available to all K-12 schools, public and private, in Kentucky Power's service territory with normal maximum demands greater than 100 kW. Tariff K-12 School rates continue to be designed with a $500,000 subsidy absorbed by Tariff L.G.S. customers.

In its Settlement Testimony, KCUC asserted that the Settlement is unfair and unreasonable because L.G.S. customers had to absorb the subsidy to provide a $500,000 benefit for Tariff K-12 School customers, in addition to a significant inter-class subsidy burden as part of the overall rate structure.[144] KCUC stated that it did not object to the $500,000 discount to Tariff K-12 School customers, but instead objected that the discount is funded by L.G.S. customers, and not spread out among all customer classes. As a remedy, KCUC proposed that, if the Commission reduced the revenue requirement, that the first $500,000 of any reduction be applied first to reduce the revenue requirement of the L.G.S. class.

[142] Case No. 2014-00396, Final Order, at 19.

[143] *Id.*

The Commission finds that load research data collected and analyzed by Kentucky Power demonstrates that a separate, discounted K-12 schools tariff is not justified and that public school usage characteristics do not support the discounted rates paid by Tariff K-12 School customers relative to the L.G.S. class. The Commission finds that it is unreasonable to continue Tariff K-12 School, and therefore rejects this portion of the Settlement.

Green Pricing Option Rider/Renewable Power Option Rider

Kentucky Power proposed to revise its Green Pricing Option Rider to expand the categories of renewable energy credits available, to allow participating customers to purchase their full requirements from renewable energy generators, and to change the name of the rider to the Renewable Power Option Rider ("Rider R.P.O"). The Commission finds that the Rider R.P.O. provision in the Settlement is reasonable and should be approved.

Tariff C.A.T.V.

In its Application, Kentucky Power proposed to increase Tariff C.A.T.V. rates for pole attachments on a two-user pole from $7.21 per year to $11.97 per year, and for pole attachments on a three-user pole from $4.47 per year to $7.52 per year. In the Settlement, Kentucky Power and the Settling Intervenors agreed to a rate of $10.82 per year for attachments on a two-user pole, and $6.71 per year for attachments on a three-user pole.

The Commission finds that the rates for Tariff C.A.T.V. as set forth in the Settlement are reasonable and should be approved.

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[144] Higgins Settlement Testimony at 2.

Temporary Service Tariff

In its Application, Kentucky Power proposed to revise its Temporary Service Tariff ("Tariff T.S.") to limit service provided under Tariff T.S. to ensure that customers do not continue to take service under Tariff T.S. even after construction is complete and the facility is occupied. The Commission finds these changes to be reasonable and that they should be approved.

Optional Residential Demand Charge Tariff

Kentucky Power proposed a new optional residential rate schedule ("Tariff R.S.D.") that will be available to up to 1,000 residential customers. The rate structure will consist of a monthly service charge, on-peak and off-peak kWh energy charges, and an on-peak kW demand charge. Kentucky Power stated that the goal of Tariff R.S.D. is to send targeted price signals that will reward customers for shifting usage away from the peak time periods that cause Kentucky Power to incur higher costs. Kentucky Power also stated that certain electric heating customers may benefit from Tariff R.S.D. due to their potentially higher load factor usage characteristics, and that the rate design is revenue neutral to the standard residential tariff.[145]

The Commission finds the proposed Tariff R.S.D. to be reasonable, that it should be approved, and that the rates included in Appendix C of this Order should be approved.

Tariff C.S.-Coal, Tariff C.S.-I.R.P. and Tariff E.D.R.

The Settlement extends through December 31, 2018, Tariff C.S.-Coal and the amendments to Tariff C.S.-I.R.P. and Tariff E.D.R., which were due to expire December

[145] Vaughan Direct Testimony at 19

31, 2017. The Commission finds the extension of the tariffs reasonable and that they should be approved. Any financial loss incurred in connection with these tariffs will be deferred for review and recovery in Kentucky Power's next base rate proceeding.

ENVIRONMENTAL COMPLIANCE PLAN

In its Application, Kentucky Power requested Commission approval of an amended environmental Compliance Plan ("2017 Plan") and an amended Environmental Surcharge tariff ("Tariff E.S.").

The 2017 Environmental Compliance Plan

The 2017 Plan includes previously approved projects and two new projects, Project 19 and Project 20. The 20 projects included in the 2017 Plan are listed in Appendix D to this Order.

Project 19 will install SCR technology at Rockport Unit 1 ("Rockport Unit 1 SCR Project"). The Rockport Unit 1 SCR project will reduce the plant's nitrogen oxide emissions, and is required under terms of a 2007 Consent Decree ("Consent Decree") among several AEP entities including Kentucky Power and I&M, and the Environmental Protection Agency and several environmental plaintiffs.

Project 20 seeks to include a return on inventories for consumables used in conjunction with approved projects through Tariff E.S. Kentucky Power currently recovers the cost of the consumption of consumables through Tariff E.S. The return on consumable inventories is currently part of the general rate base. Kentucky Power proposed that the return on consumable inventories be recovered through Tariff E.S. to align that cost with the cost recovery of items consumed.

Kentucky Power stated that the pollution control projects included in the 2017 Plan amendment are necessary to comply with the Federal Clean Air Act ("CAA") and other federal, state, and local regulations that apply to coal combustion wastes and by-products from facilities utilized for the production of energy from coal. Kentucky Power asserted that the costs associated with its 2017 Plan are reasonable, and that the projects are a reasonable and cost-effective means to comply with environmental requirements.

The Attorney General argued that Kentucky Power should not be permitted to recover the cost of the Rockport Unit 1 SCR Project.[146] The Attorney General asserted that Kentucky Power's customers have been paying increasing amounts for environmental costs resulting from the Consent Decree because AEP voluntarily made environmental upgrades at generating stations, including the Rockport generating units, that were not identified in the original EPA litigation that led to the Consent Decree. Because Rockport was not part of the original litigation, the Attorney General asserts Kentucky Power should not recover the costs for the Rockport Unit 1 SCR project from its ratepayers.

In rebuttal, Kentucky Power stated that the decision to include Rockport in the Consent Decree settlement was a way to remove the significant risk of additional litigation at those units not named in any pending complaints, as well as to provide a more favorable outcome than would be expected on an individual basis.[147] Kentucky Power further stated that the Consent Decree provided certainty regarding the timing of

[146] Smith Testimony at 59.
[147] Rebuttal Testimony of John McManus at 3.

additional control installations across the AEP fleet. At the time of the settlement, Kentucky Power was still participating in the AEP Pool, which meant that the outcome of litigation involving all units across the AEP fleet contributing to the pool was in the best interest of Kentucky Power and its customers.

The Settlement was silent on the 2017 Environmental Compliance Plan.

The Commission finds that the 2017 Plan is reasonable as set forth in the Application and should be approved.

<u>ENVIRONMENTAL SURCHARGE TARIFF MODIFICATIONS</u>

Kentucky Power updated its Tariff E.S. to reflect the changes proposed in its Application and the Settlement. Kentucky Power updated the list of projects in the tariff to match the projects included in the 2017 Plan as noted previously in this Order. Kentucky Power updated Tariff ES to reflect the rate of return included in the Settlement to this case. Kentucky Power also updated the tariff to reflect the new monthly base environmental costs based on that rate of return. Kentucky Power determined the annual base revenue requirement level for environmental cost recovery to be \$47,513,461.[148] The Commission has determined that the correct annual base revenue requirement is \$44,379,316, which reflects the Commission authorized return on equity, capital structure changes, reduction of the federal corporate income tax rate from 35 percent to 21 percent and the depreciation rates set forth in Exhibit 5 of the

[148] In the Tariff E.S. filed December 1, 2017, Kentucky Power reflected an annual base revenue requirement of \$47,811,215. Kentucky Power updated this amount to \$47,513,461 to reflect the depreciation rates included in Exhibit 5 to the Settlement Agreement. See Response to Commission Staff's Post-Hearing Request for Information ("Staff's Post-Hearing Request"), Item 20 attachment KPCO_R_KPSC_PH_20_Attachment1.xls.

Settlement.[149] Kentucky Power shall file a revised Tariff ES to reflect the Commission authorized return on equity and capitalization discussed in this Order, and the annual base revenue requirement as shown on Appendix E attached to this order. Per the settlement agreement in Case No. 2012-00578,[150] all costs associated with the Mitchell FGD equipment are excluded from base rates and therefore are not included in the base revenue requirement noted above, but will be included as part of the current period environmental revenue requirement. The Commission finds that Tariff E.S. as discussed and modified in this Order should become effective for service rendered on and after the date of this Order.

Costs Associated with the 2015 Plan

Tariff E.S. revenue requirement is determined by comparing the base period revenue requirement with the current period revenue requirement. Kentucky Power proposed to incorporate the costs associated with the 2017 Plan into the existing surcharge mechanism used for previous compliance plans. Kentucky Power identified the environmental compliance costs for the 2017 Plan projects, which Kentucky Power proposed to recover through its environmental surcharge. Kentucky Power proposed to apply a gross-up factor to environmental expenses to account for uncollectible accounts and the Commission assessment fee. The factor will be applied to the incremental change in operating, maintenance, and other expenses from the base period. The

[149] Response to Staff's Post-Hearing Request, Item 20.

[150] Case No. 2012-00578, *Application of Kentucky Power Company for (1) a Certificate of Public Convenience and Necessity Authorizing the Transfer to the Company of an Undivided Fifty Percent Interest in the Mitchell Generating Station and Associated Assets; (2) Approval of the Assumption by Kentucky Power Company of Certain Liabilities in Connection with the Transfer of the Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral of Costs Incurred in Connection with the Company's Efforts to Meet Federal Clean Air Act and Related Requirements; and (5) All Other Required Approvals and Relief* (Ky. PSC Oct. 7, 2013).

costs identified by Kentucky Power are eligible for surcharge recovery if they are shown to be reasonable and cost-effective for complying with the environmental requirements specified in KRS 278.183. The Commission finds that the costs identified for the 2017 Plan projects have been shown to be reasonable and cost-effective for environmental compliance. Thus, they are reasonable, and should be approved for recovery through Kentucky Power's environmental surcharge.

Qualifying Costs

As stated previously, the qualifying costs included in Kentucky Power's annual baseline level for environmental cost recovery under the tariff shall be $44,379,316. The qualifying costs included in the current period revenue requirement will reflect the Commission-approved environmental projects from Kentucky Power's 1997, 2005, 2007, 2015 and 2017 Plans. Per the settlement agreement in Case No 2012-00578, all costs associated with Mitchell Units 1 and 2 FGD equipment have been excluded from base rates and the environmental baseline level and shall be recovered exclusively through Tariff E.S. Should Kentucky Power desire to include other environmental projects in the future, it will have to apply for an amendment to its approved compliance plans.

Rate of Return

Paragraph 8(a) of the Settlement authorizes Kentucky Power to use a 9.75 percent ROE to be utilized in Tariff E.S. to determine the WACC for non-Rockport environmental projects. However as previously noted, the Commission has authorized a 9.70 percent ROE that should be used for all non-Rockport environmental projects.

Kentucky Power's ROE for environmental projects at the Rockport Plant is 12.16 percent as established by the FERC-approved Rockport Unit Power Agreement.

Capitalization and Gross Revenue Conversion Factor

Paragraph 3(c) and Exhibit 6 of the Settlement provide that Kentucky Power shall utilize a WACC of 6.48 percent and a gross revenue conversion factor ("GRCF") of 1.6433 to determine a rate of return of 9.11 percent to be used in the monthly environmental surcharge filings. As a result of the reduction of the federal corporate tax rate from 35 percent to 21 percent, the Commission has determined that Kentucky Power should use a GRCF of 1.352116. Because of the change in the authorized ROE, capitalization, and the GRCF, the WACC to be used for non-Rockport environmental projects is 6.44 percent. Utilizing a WACC of 6.44 percent and a GRCF produces a rate of return of 7.88 percent to be used in the monthly environmental surcharge filings. The WACC and GRCF shall remain constant until the Commission sets base rates in Kentucky Power's next base rate case proceeding.

Surcharge Formulas

The inclusion of the 2017 Plan into Kentucky Power's existing surcharge mechanism will not result in changes to the surcharge formulas. The costs associated with the Mitchell FGD will be excluded from base rates and the base rate revenue requirement of the environmental surcharge at least until June 30, 2020, but will be included in the current period revenue requirement for the environmental surcharge. The Commission finds that the formulas used to determine the environmental surcharge revenue requirement as proposed by Kentucky Power should be approved.

Surcharge Allocation

The retail share of the revenue requirement will be allocated between residential and non-residential customers based upon their respective total revenue during the previous calendar year. The environmental surcharge will be implemented as a percentage of total revenues for the residential class and as a percentage of non-fuel revenues for all other customers.

Monthly Reporting Forms

The inclusion of the 2017 Plan into the existing surcharge mechanism will require modifications to the monthly environmental surcharge reporting forms. Kentucky Power provided its proposed revised forms to be used in the monthly environmental reports. The revised forms include the changes necessary to reflect the proposed 2017 Plan, as well as changes necessitated by the application of a gross-up factor to the incremental operating, maintenance and other expenses. The Commission finds that Kentucky Power's proposed monthly environmental surcharge reporting forms as revised should be approved.

FINDINGS ON SETTLEMENT AGREEMENT

Based upon a review of all the provisions in the Settlement, an examination of the entire record, and being otherwise sufficiently advised, the Commission finds that the provisions of the Settlement are in the public interest and should be approved, subject to the modifications as discussed in this Order. Our approval of the Settlement as modified is based solely on its reasonableness and does not constitute precedent on any issue except as specifically provided for in this Order.

OTHER ISSUES

Vegetation Management

Kentucky Power's current Vegetation Management Plan ("2015 Vegetation Management Plan") was modified from its 2010 Vegetation Management Plan in Kentucky Power's last rate case, Case No. 2014-00396. In Case No. 2014-00396, it was determined that funding for the 2010 Vegetation Management Plan, which was scheduled to move to a four-year cycle within seven years of initial circuit clearing, needed modification. However, the work required to transition to a four-year cycle was significantly greater than initially estimated, and Kentucky Power could not wait until all circuits had an initial clearing ("Task 1") to begin re-clearing the circuits. Thus, the modification was approved allowing the continuation of Task 1 and a simultaneous undertaking of interim re-clearing ("Task 2"). Under this schedule, Task 1 would be completed by December 31, 2018, Task 2 would be completed by June 30, 2019, and on July 1, 2019, Kentucky Power's entire distribution system would commence to be re-cleared on a five-year cycle ("Task 3"), rather than a four-year cycle. Funding was approved for the 2015 Vegetation Management Plan, as well as a provision requiring Kentucky Power to obtain Commission approval prior to modifying its annual projected vegetation management spending on both an aggregate and a district basis if the change is more than 10 percent of the budget.

Kentucky Power is on pace to exceed the December 31, 2018 target for Task 1, and expects to complete Task 1 circuit clearing in the first quarter of 2018. In addition, Task 2 circuit re-clearing is expected to be completed by December 31, 2018, six months sooner than projected. To date, Kentucky Power has exceeded targets on budget as total expenditures are 101 percent of target level.[151] Reliability has increased

[151] Application, Direct Testimony of Everett G. Phillips ("Phillips Testimony") at 35.

and Kentucky Power customers have seen a 60 percent decrease in interruptions related to rights-of-way trees and vegetation.[152] Task 3 is estimated to begin in January 2019.

Embedded in Kentucky Power's current base rates are annual vegetation management O&M expenses of $27.661 million. Due to early completion of Tasks 1 and 2, Kentucky Power estimates a reduction of O&M expenses related to Tasks 1 and 2 from $27.661 million in 2017 to $21.639 million 2018. According to the 2015 Vegetation Management Plan, at the start of Task 3, O&M expenses are projected to decrease, resulting in a decrease of O&M expenses of $11.780 million. However, Kentucky Power has determined that the estimates of the annual O&M expenditures for Task 3 as estimated in the 2015 Vegetation Management Plan are undervalued and need to be increased.[153] Due to the re-clearing in Task 2, Kentucky Power now has a better grasp on regrowth, the effect of higher-than-average rainfall, and growing customer demand to remove tree debris, and proposes to increase the annual O&M expenses for Task 3. This re-estimation calculates costs for Task 3 to increase from the original $15.880 million to $21.284 million in 2019, and $21.473 in 2020.[154] Kentucky Power proposes the amount of vegetation management O&M expenses to be recovered through base rates for the instant case to be equal to the average of the revised estimated annual vegetation management plan O&M spending over 2018-2020, or $21.465 million.[155]

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[152] *Id* at 40.

[153] *Id.*

[154] *Id.* at 46

Kentucky Power also proposes two changes to its current vegetation management reporting requirements. First, Kentucky Power proposes to modify the pre-approval requirement for deviation of 10 or more percent from projected annual vegetation management O&M expenditures to eliminate the district-specific threshold and retain only the requirement for pre-approval if overall Kentucky Power vegetation management expenditures deviate more than 10 percent. Second, Kentucky Power proposes to manage its vegetation work and expenditures on a calendar year basis, as opposed to managing its vegetation work on a fiscal year and expenditures on a calendar year. Kentucky Power stresses that neither modification will change their overall vegetation management obligation, but provides for more flexibility to manage its obligations.[156]

The 2015 Vegetation Management Plan included a one-way balancing account. In this balancing account, any annual shortfall or excess in vegetation management O&M expenditures that is over the amount in base rates is added to or subtracted from future expenditures over four years. At the end of the four-year period, Kentucky Power will record a cumulative shortfall as a regulatory liability that will either be refunded to the customers or used to reduce the revenue requirement in its next filed base-rate case. If Kentucky Power has overspent on a cumulative basis during the four-year period, it will not seek recovery of such costs in a future base-rate proceeding. As of the end of November 2017, Kentucky Power testified that cumulative expenditures were slightly over the budgeted amount.[157]

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[155] Application, Section V, Exhibit 2, page 59.

[156] *Id.* at 43.

The Commission finds that the one-way balancing adjustment should be continued; however due to the change in the annual revenue requirement as noted in the Application, it should be adjusted accordingly. All expenses will be recorded against the annual budget. The annual shortfall or excess will be applied to the balance account. Through 2023, or until Kentucky Power's next base rate application, whichever occurs first, the expenditures will be balanced against the annual projected expenditures as found in the Application.[158]

The Commission approves the proposed modifications allowing Kentucky Power to request Commission approval for any spending deviation greater than 10 percent on an aggregate level as opposed to a district level. The Commission also approves Kentucky Power's request to manage its vegetation management program on a calendar year basis to coincide with the budgetary year. The Commission notes that Kentucky Power has exceeded the goals of the 2015 Vegetation Management Plan resulting in a reduction of O&M expenses 24 months earlier than estimated. The Commission approves Kentucky Power's proposed revenue requirement of $21.465 million. All other provisions of the 2015 Vegetative Management Plan are to remain unchanged.

The Commission will continue to review closely the vegetation management annual work plans and expenditures filed by Kentucky Power. In addition, the Commission will monitor the progress of the five-year maintenance cycle.

Bill Redesign

[157] Dec. 8, 2017 H.V.T. at 2:09:38.

[158] Phillips Testimony, Table 9 at 46.

On June 12, 2017, Kentucky Power filed an Application requesting approval to implement new bill formats that change the bill layout and composition, which is being implemented concurrently for all AEP operating companies, and to combine certain billing line items. That Application was docketed as Case No. 2017-00231.[159] By Order dated July 17, 2017, that case was consolidated into this proceeding. By further Order dated September 12, 2017, the Commission approved Kentucky Power's request to redesign the appearance of its bills, but stated that a decision on the proposed substantive changes to consolidate billing line items would be determined in the final Order in this proceeding.

Kentucky Power proposed to consolidate eight residential billing line items,[160] and seven commercial and industrial billing line items[161] into a single "Rate Billing" line item. Kentucky Power explained that customer satisfaction regarding billing correspondence was below the industry average according to a survey commissioned by Kentucky Power.[162] Kentucky Power asserted that its customers found the number of billing line

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[159] Case No. 2017-00231, *Electronic Application of Kentucky Power Company for (1) Approval of Its Revised Terms and conditions of Service Implementing New Bill Formats; (2) An Order Granting All other Required Approvals and Relief* (filed June 12, 2017).

[160] The residential billing line items Kentucky Power proposes to consolidate into a single line items are Rate Billing, Residential Home Energy Assistance Program Charge, Kentucky Economic Development Surcharge, Capacity charge, Big Sandy 1 Operation Rider, Big Sandy Retirement Rider, Purchased Power Adjustment, and Green Pricing Option. The residential charges that Kentucky Power proposes to continue to display as individual billing line items are the Fuel Adjustment Charge, Demand-Side Management Factor, Environmental Surcharge, School Tax, Franchise Fee, State Sales tax, and HomeServe Warranty.

[161] The commercial and industrial billing line items Kentucky Power proposes to consolidate into a single line items are Rate Billing, Kentucky Economic Development Surcharge, Capacity charge, Big Sandy 1 Operation Rider, Big Sandy Retirement Rider, Purchased Power Adjustment, and Green Pricing Option. The commercial and industrial charges that Kentucky Power proposes to continue to display as individual billing line items are the Fuel Adjustment Charge, Demand-Side Management Factor, Environmental Surcharge, School Tax, Franchise Fee, and State Sales tax.

[162] Case No. 2017-00231, Direct Testimony of Stephen L. Sharp, Jr. (filed June 12, 2017) at 2.

items were "unhelpful," made the bills "difficult to understand," and obscured the information customers most wanted to know, which was the total amount owed and payment due date.[163] Kentucky Power further asserted that customers requested that line items be consolidated in order to simplify the bills. Customers who want detailed billing information could contact a Kentucky Power customer service center.

In the Settlement, the Settling Intervenors agreed to Kentucky Power's proposed consolidation of billing line items.

Neither KCUC nor the Attorney General filed testimony in this proceeding regarding the consolidation of billing line items. However, in a motion filed in Case No. 2017-00231 before it was incorporated into this proceeding, the Attorney General argued that consolidating the billing line items would result in a lack of transparency that impeded customers' understanding of how rates and their bills are calculated.[164]

The Commission finds that Kentucky Power's proposed consolidation of billing line items is unreasonable and should be denied. The Commission concurs with the Attorney General that displaying discrete billing line items on customer bills promotes transparency and customer understanding of their billing amounts. Further, it is not reasonable to require customers to take additional steps in order to obtain a detailed accounting for their bills. This is especially so given that the billing line items that Kentucky Power wishes to consolidate represent charges in addition to the base rate charge for utility service.

<u>Analysis of Kentucky Power's Participation in PJM</u>

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[163] *Id.* at 3; *Id.* at Application, paragraph 11.

Kentucky Power currently elects to self-supply its PJM capacity requirements under the Fixed Resource Requirement ("FRR") alternative. As discussed in testimony at the hearing, AEP conducts regular evaluations to determine whether its operating companies in PJM should elect to participate in the Reliability Pricing Model ("RPM") capacity market, or to self-supply under FRR.[165]

The Commission finds that Kentucky Power should file an annual update of the FRR/RPM election analysis. The Commission recognizes that this information is deemed confidential during the AEP internal decision-making process. However, once PJM is notified of the election, the information becomes public and ceases to be confidential. Kentucky Power should file the annual update after the information becomes public.

Further, the Commission recognizes that Kentucky Power's interests may not be aligned with the interests of other AEP operating companies. The Commission is aware that PJM bills AEP based on a one-coincident peak methodology, and that AEP subsequently allocates those costs to its operating companies using a twelve-coincident peak methodology. The Commission finds that Kentucky Power should file an annual report with the supporting calculations used by AEP to allocate these costs.

Last, the Commission strongly encourages Kentucky Power to recognize that it must make a determination regarding its participation in PJM that aligns with the interests of Kentucky Power and its ratepayers.

<u>Reduction in Corporate Tax Rates</u>

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[164] Case No. 2017-00231, Attorney General's Motion to Consolidate Cases (filed July 13, 2017) paragraphs 4-5.

[165] Dec. 7, 2017 H.V.T. at 10:43:18, and Kentucky Power Exhibit 9.

Effective January 1, 2018, the federal corporate income tax rate was reduced from 35 percent to 21 percent. Consistent with Kentucky Power's revised gross-up factor calculation in certain riders, the Commission finds that it is reasonable to utilize the 21 percent corporate income tax rate in the gross-up factor calculation. The Commission will address the impact of the recently enacted tax cuts on the excess ADIT and the rates of all investor-owned utilities, including Kentucky Power, on a prospective basis in pending cases that were opened on December 27, 2017.[166]

Based on the evidence of record and the findings contained herein, HEREBY ORDERS that:

1. The rates and charges proposed by Kentucky Power are denied.

2. The provisions in the Settlement, as set forth in Appendix A to this Order, are approved, subject to the modifications and deletions set forth in this Order.

3. The rates and charges for Kentucky Power, as set forth in Appendix C to this Order, are the fair, just, and reasonable rates for Kentucky Power, and these rates are approved for service rendered on and after January 19, 2018.

4. Kentucky Power's request to deviate from 807 KAR 5:006, Section 14(2)(a) by limiting enrollment in its Equal Payment Plan to the months of April through December is granted.

5. Kentucky Power's proposed depreciation rates, with the exception of the changes proposed in the Settlement are approved.

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[166] Case No. 2017-00477, *Kentucky Industrial Utility Customers, Inc. v. Kentucky Utilities Company, Louisville Gas and Electric Company, Kentucky Power Company, and Duke Energy Kentucky, Inc.* (Ky PSC Dec. 27, 2017); Case No. 2017-00481, *An Investigation of the Impact of the Tax Cuts and Job Act on the Rates of Atmos Energy Corporation, Delta Natural Gas Company, Inc., Columbia Gas of Kentucky, Inc., Kentucky-American Water Company, and Water Service Corporation of Kentucky* (Ky. PSC Dec. 27, 2017).

6. The regulatory asset or liability account established by under- or over-recovery from the elimination of Tariff B.S.1.O.R. is approved for accounting purposes only.

7. The regulatory asset account established by the deferral of Rockport UPA expenses is approved for accounting purposes only.

8. Kentucky Power's 2017 Environmental Compliance Plan is approved.

9. Kentucky Power's environmental surcharge tariff is approved for service rendered on and after the date of this Order.

10. The base period and current period revenue requirements for the environmental surcharge shall be calculated as described in this Order.

11. The environmental reporting formats described in this Order shall be used for the monthly environmental surcharge filings. Previous reporting formats shall no longer be submitted.

12. The Commission approves the sample forms that were filed by Kentucky Power on January 3, 2018.

13. Within three months of the date of this Order, Kentucky Power shall identify and contact GS class customers whose average monthly demand is 25 kW or greater for the purpose of meeting to discuss the impact of the rate increase on their bills and analyze other available tariff options, such as time-of-day rates.

14. Within twelve months of the date of this Order, Kentucky Power shall file a report listing the names of each GS class customers whose average monthly demand is 25 kW or greater, and stating the date and method of contact with the customer, whether Kentucky Power has met with the customer, and the results of each meeting.

15. Kentucky Power's request to revise its billing format to consolidate billing line items, as set forth in the application, is denied.

16. Kentucky Power's Vegetation Management Plan, as set forth in the Application, is approved.

17. Kentucky Power's request to obtain Commission approval for any spending deviation from its Vegetation Management Plan greater than 10 percent on an aggregate level as opposed to a district level is approved.

18. Kentucky Power's request to manage its Vegetation Management Plan on a calendar year basis is approved.

19. Kentucky Power shall file an annual update of the FRR/RPM election analysis conducted by AEP and its operating companies within 30 days of notifying PJM of the election.

20. Kentucky Power shall file annually the supporting calculations for allocating PJM bills, which are based on a one-coincident peak methodology, AEP's operating companies using a twelve-coincident-peak methodology.

21. Within 20 days of the date of this Order, Kentucky Power shall, using the Commission's electronic Tariff Filing System, file its revised tariffs setting out the rates authorized herein and reflecting that they were approved pursuant to this Order.

By the Commission

ENTERED
JAN 18 2018
KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Gwen R. Pinson

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00179 DATED JAN 18 2018

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets Or Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)	Case No. 2017-00179

SETTLEMENT AGREEMENT

This Settlement Agreement, made and entered into this 22nd day of November, 2017, by and among Kentucky Power Company ("Kentucky Power" or "Company"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Kentucky School Boards Association ("KSBA"); Kentucky League of Cities ("KLC"); Wal-Mart Stores East, LP and Sam's East, Inc. ("Wal-Mart"); and Kentucky Cable Telecommunications Association ("KCTA"); (collectively Kentucky Power, KIUC, KSBA, KLC, Wal-Mart, and KCTA, are "Signatory Parties").

RECITALS

1. On June 28, 2017 Kentucky Power filed an application pursuant to KRS 278.190, KRS 278.183, and the rules and regulations of the Public Service Commission of Kentucky ("Commission"), seeking an annual increase in retail electric rates and charges totaling $69,575,934, seeking approval of its 2017 Environmental Compliance Plan, an order approving accounting practices to establish regulatory assets or liabilities, and further seeking authority to implement or amend certain tariffs ("June 2017 Application").

2. On August 8, 2017, Kentucky Power supplemented its filing to reflect the impact of subsequent refinancing activities on the Company's Application ("August 2017 Refinancing Update"). The refinancing activities reduced the Company's requested annual increase in retail electric rates and charges from $69,575,934 to $60,397,438.

3. KIUC, KSBA, KLC, Wal-Mart, and KCTA filed motions for full intervention in Case No. 2017-00179. The Commission granted the intervention motions. Collectively KIUC, KSBA, KLC, Wal-Mart, and KCTA are referred to in this Settlement Agreement as the "Settling Intervenors."

4. The Attorney General of the Commonwealth of Kentucky ("Attorney General") and Kentucky Commercial Utility Customers, Inc. ("KCUC") also filed motions to intervene. The Attorney General and KCUC, who are not parties to this agreement, were granted leave to intervene.

5. Certain of the Settling Intervenors, KCUC, and the Attorney General filed written testimony in Case No. 2017-00179 raising issues regarding Kentucky Power's Rate Application.

6. Kentucky Power, KCUC, the Attorney General, and the Settling Intervenors have had a full opportunity for discovery, including the filing of written data requests and responses.

7. Kentucky Power offered the Settling Intervenors, KCUC, and the Attorney General, along with Commission Staff, the opportunity to meet and review the issues presented by Kentucky Power's application in this proceeding and for purposes of settlement.

8. The Signatory Parties execute this Settlement Agreement for purposes of submitting it to the Kentucky Public Service Commission for approval pursuant to KRS 278.190 and KRS 278.183 and for further approval by the Commission of the rate increase, rate structure, and tariffs as described herein.

9. The Signatory Parties believe that this Settlement Agreement provides for fair, just, and reasonable rates.

NOW, THEREFORE, for and in consideration of the mutual promises set forth above, and the agreements and covenants set forth herein, Kentucky Power and the Settling Intervenors hereby agree as follows:

AGREEMENT

1. Kentucky Power's Application

(a) Except as modified in this Settlement Agreement, Kentucky Power's June 2017 Application as updated by the August 2017 Refinancing Update is approved.

2. Revenue Requirement

(a) Effective for service rendered on or after January 19, 2018, Kentucky Power shall implement a base rate adjustment sufficient to generate additional annual retail revenues of $31,780,734. This annual retail revenue amount represents a $28,616,704 million reduction from the $60,397,438 sought in the Company's August 2017 Refinancing Update.

(b) The $28,616,704 million reduction was the result of the following adjustments to the Company's request in the June 2017 Rate Application as modified in the August 2017 Refinancing Update:

Adjustment	**Reduction in Revenue Requirement ($Millions)**
Defer a portion of Rockport UPA non-fuel, non-environmental expenses	15.0
Increase revenues to Apply Weather Normalization to Commercial Sales Net of Variable O&M	0.40
Reduce Incentive Compensation	3.15
Reduce Amortization Expense to Recalibrate Storm Damage Amortization	1.22

Reduce Depreciation Expense by Extending Service Life of BS1 to 20 years	2.84
Reduce Depreciation Expense by Removing Terminal Net Salvage for BSU1	0.37
Reduce Depreciation Expense by Removing Terminal Net Salvage for Mitchell	0.57
Increase Short Term Debt to 1% and Set Debt Rate at 1.25%	0.36
Change in Return on Equity from 10.31% to 9.75%	4.70
Total Adjustments	**28.6**

(c) Kentucky Power agrees to allocate the $31,780,734 in additional annual revenue as illustrated on **EXHIBIT 1.** The Company will design rates and tariffs consistent with this allocation of additional revenue.

(i) As part of the Commission's consideration of the reasonableness of this Settlement Agreement, the tariffs designed in accordance with this subparagraph shall be filed with the Commission and served on counsel for all parties to this case no later than December 1, 2017.

(ii) Within ten days of the entry of the Commission's Order approving without modification this Settlement Agreement and the rates thereunder, Kentucky Power shall file with the Commission signed copies of the tariffs in conformity with 807 KAR 5:011.

3. Rockport UPA Expense Deferral

(a) Kentucky Power is a party to a FERC-approved Unit Power Agreement with AEP Generating Company for capacity and energy produced at the Rockport Plant ("Rockport UPA"). The Rockport UPA expires on December 8, 2022.

(b) Kentucky Power will defer a total of $50 million in non-fuel, non-environmental Rockport UPA Expense for later recovery as follows:

(i) Kentucky Power will defer $15M annually of Rockport UPA Expense in 2018 and 2019 for later recovery.

(ii) Kentucky Power will defer $10M of Rockport UPA Expense in 2020 for later recovery.

(iii) Kentucky Power will defer $5M annually of Rockport UPA Expense in years 2021 and 2022 for later recovery.

(c) The Rockport UPA Expense of $50 million described in Paragraph 3(b) above will be deferred into a regulatory asset ("the Rockport Deferral Regulatory Asset") and will be subject to carrying charges based on a weighted average cost of capital ("WACC") of 9.11%[1] until the Regulatory Asset is fully recovered. From January 1, 2018 through December 8, 2022, the WACC will be applied to the monthly Rockport Deferral Regulatory Asset principal balance net of accumulated deferred income taxes ("ADIT"). From December 9, 2022 until the Rockport Deferral Regulatory Asset is fully recovered, the WACC will be applied to the monthly Rockport Deferral Regulatory Asset balance including deferred carrying charges net of ADIT. The Rockport Deferral Regulatory Asset shall be recovered on a levelized basis through the demand component of Tariff P.P.A. and amortized over five years beginning on December 9, 2022. Kentucky Power estimates that the regulatory asset balance will total approximately $59 million on December 8, 2022.

(d) Additional expenses reflecting the declining deferral amount in years 2020 through 2022 will be recovered through the demand component of Tariff P.P.A. as follows:

(i) Kentucky Power will recover $5 million through Tariff P.P.A. in 2020

(ii) Kentucky Power will recover $10 million through Tariff P.P.A. in 2021

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[1] 6.48% grossed up for applicable State and Federal taxes, uncollectible accounts expense, and the KPSC maintenance fee

(iii) Kentucky Power will recover $10 million through Tariff P.P.A. in 2022, prorated through December 8, 2022.

(e) The Signatory Parties acknowledge that the Company's decision whether to seek Commission approval to extend the Rockport UPA will be made at a later date. Whether or not the Company seeks to extend the Rockport UPA, beginning December 9, 2022, the Capacity Charge recovered through Tariff C.C., approved in Case No. 2004-00420, will end. Any final over- or under-recovery balance will be included in the subsequent calculation of the purchase power adjustment under Tariff P.P.A. In the event that Kentucky Power elects not to extend the Rockport UPA, it will experience a reduction in Rockport UPA fixed costs ("Rockport Fixed Costs Savings").

(f) If Kentucky Power elects not to extend the Rockport UPA, it will, beginning December 9, 2022, credit the Rockport Fixed Cost Savings through the demand component of Tariff P.P.A. until new base rates are set. However, for 2023 only, the Rockport Fixed Cost Savings credit will be offset by the amount, if any, necessary for the Company to earn its Kentucky Commission-authorized return on equity (ROE) for 2023 ("Rockport Offset"). An example of the calculation of the Rockport Offset is included as **Exhibit 2**.

(g) For the purposes of implementing the Rockport Fixed Costs Savings credit described in Paragraph 3(f) above, the following definitions apply:

(i) "Rockport Fixed Costs Savings" shall mean the annual amount of non-fuel, non-environmental Rockport UPA expense included in base rates for rates effective in November 2022.

(ii) "Estimated Rockport Offset" shall mean the amount of additional annual revenue the Company estimates would be necessary for it to earn the Commission-authorized

return on equity for 2023 considering the termination of the Rockport UPA and the Rockport Fixed Cost Savings.

(iii) "Actual Rockport Offset" shall mean the amount of additional annual revenue that would have been necessary for the Company to earn the Commission-authorized return on equity for 2023 considering the termination of the Rockport UPA and the Rockport Fixed Cost Savings. The Company shall calculate the Actual Rockport Offset using a comparison of the per books return on equity for 2023 to the Commission-approved return on equity. The Actual Rockport Offset cannot exceed the Rockport Fixed Costs Savings.

(iv) "Rockport Offset True-Up" shall mean the difference between the Estimated Rockport Offset and the Actual Rockport Offset.

(h) The Company shall implement the Rockport Fixed Costs Savings credit described in Paragraph 3(f) above as follows:

(i) By November 15, 2022, the Company shall file an updated purchase power adjustment factor under Tariff P.P.A. for rates effective December 9, 2022. This filing shall reflect the impact of the Rockport Fixed Cost Savings and the Estimated Rockport Offset on the purchase power adjustment factor. This filing shall also reflect the commencement of recovery of the Rockport Deferral Regulatory Asset.

(ii) The Company shall make its normal August 15, 2023 Tariff P.P.A. filing for rates effective in October 2023. The Rockport Fixed Cost Savings and the Estimated Rockport Offset will continue to be factored into the calculation of the purchase power adjustment factor through the end of 2023. Beginning in January 2024, the Estimated Rockport Offset will not be factored into the calculation of the purchase power adjustment factor.

(iii) By February 1, 2024, the Company shall file an updated purchase power adjustment factor under Tariff P.P.A. for rates effective March 1, 2024. This filing shall only reflect the impact of the Rockport Offset True-Up on the purchase power adjustment factor. The purchase power adjustment factor shall be established to recover or credit the Rockport Offset True-Up amount in three months.

(iv) Beginning with the August 15, 2024 Tariff P.P.A. filing, the Company will incorporate the Rockport Fixed Cost Savings in its annual calculation of the purchase power adjustment factor.

4. PJM OATT LSE Expense Recovery

(a) As described in the testimony of Company Witness Vaughan, Kentucky Power has included an adjusted test year amount of net PJM OATT LSE charges and credits in base rates. Kentucky Power will track, on a monthly basis, the amount of OATT LSE charges and credits above or below the base rate level using deferral accounting. Kentucky Power will recover and collect 80% of the annual over or under collection of PJM OATT LSE charges, as compared to the annual amount included in base rates, ("Annual PJM OATT LSE Recovery") through the operation of Tariff P.P.A.

(b) Kentucky Power will credit against the Annual PJM OATT LSE Recovery 100% of the difference between the return on its incremental transmission investments calculated using the FERC-approved PJM OATT return on equity and the return on its incremental transmission investments calculated using the 9.75% return on equity provided for in this settlement (the "Transmission Return Difference"). Kentucky Power shall calculate the Transmission Return Difference as shown in **Exhibit 3**.

(c) These changes to Tariff P.P.A. to allow for the Annual PJM OATT LSE Recovery will terminate on the effective date when base rates are reset in the next base rate proceeding unless otherwise specifically extended by the Commission. Nothing in this Paragraph 4(c) prohibits Kentucky Power or any other Signatory Party from taking any position regarding the extension of the Annual PJM OATT LSE Recovery mechanism or any other treatment of the Company's PJM OATT LSE expenses.

5. Rate Case Stay Out

(a) Kentucky Power will not file an application for a general adjustment of base rates for rates that would be effective prior to the first day of the January 2021 billing cycle. This rate case "stay out" is expressly conditioned on Commission approval of this Settlement Agreement without modification including the recovery of the Rockport Deferral Regulatory Asset as described in Section 3 above and the incremental PJM OATT LSE expense through Tariff P.P.A. as described in Section 4 above.

(b) This stay out will not apply if a change in law occurs that will result in a material adverse effect on the Company's financial condition.

(c) Nothing in this stay out provision should be interpreted as prohibiting the Commission from altering the Company's rates upon its own investigation, or upon complaint, including to reflect changes in the tax code, including the federal corporate income tax rate, depreciation provisions, or upon a request by the Company to seek leave to address an emergency that could adversely impact Kentucky Power or its customers. In the event the Commission initiates an investigation or a complaint is filed with the Commission regarding the Company's rates, the Company retains the right to defend the reasonableness of its rates in such proceedings.

6. Tariff P.P.A.

(a) Kentucky Power's proposed changes to Tariff P.P.A., as set forth in the testimony of Company Witness Vaughan and modified by Sections 2 and 3 above, are approved.

(b) A revised version of Tariff P.P.A. incorporating the modifications described in Sections 2 and 3 above is included as **EXHIBIT 4.**

7. Depreciation Rates

(a) Kentucky Power and the Settling Intervenors agree that Big Sandy Unit 1 has an expected life of 20 years following its conversion from a coal-fired to a natural gas-fired generating unit. The depreciation rates for Big Sandy Unit 1 have been adjusted to reflect the 20 year expected life. Kentucky Power and the Signatory Parties retain the right to propose updated depreciation rates for Big Sandy Unit 1 in future proceedings to reflect updates to the expected life.

(b) Kentucky Power has adjusted depreciation rates for Big Sandy Unit 1 and for the Mitchell Plant to remove terminal net salvage costs. Kentucky Power retains the right to propose updated depreciation rates for Big Sandy Unit 1 and for the Mitchell Plant in future proceedings to include terminal net salvage costs, and the Settling Intervenors retain the right to challenge the inclusion of such costs in future proceedings.

(c) Kentucky Power's updated depreciation rates are included as **EXHIBIT 5**.

8. Return on Equity, Capitalization, WACC, and GRCF

(a) Kentucky Power shall be authorized a 9.75% return on equity. The authorized return on equity of 9.75% will be used in the calculation of the Company's Environmental Surcharge factor (for non-Rockport environmental projects) and the carrying charges for the Rockport Deferral and Decommissioning Rider regulatory assets.

(b) Kentucky Power will update its capitalization to reflect short term debt as 1% of the Company's total capital structure. The annual interest rate for the short term debt will be set at 1.25%.

(c) Kentucky Power shall utilize a weighted average cost of capital ("WACC") of 9.11% including a gross revenue conversion factor ("GRCF") of 1.6433%. The GRCF does not include a Section 199 deduction. This WACC and GRCF shall remain constant (including for the riders and surcharges described in Paragraph 8(a) above) until such time as the Commission sets base rates in the Company's next base rate case proceeding. The calculations of the WACC and GRCF are shown on **Exhibit 6**.

9. Storm Damage Expense Amortization

(a) Kentucky Power will recover and amortize the remaining unamortized balance of its deferred storm expense regulatory asset authorized in Case No. 2012-00445 over a period of five years beginning January 1, 2018, consistent with the recommendation of KIUC. The unamortized balance of the regulatory asset authorized in Case No. 2012-00445 will total $6,087,000 on December 31, 2017 and will be amortized over five years at an annual amount of $1,217,400.

(b) Kentucky Power will recover and amortize the deferred storm expense regulatory asset authorized in Case No. 2016-00180 over a period of 5 years beginning January 1, 2018 consistent with the testimony of Company Witness Wohnhas. The balance of the regulatory asset authorized in Case No. 2016-00180 totals $4,377,336 and will be amortized over five years at an annual amount of $875,467.

(c) The combined balance of the Kentucky Power's deferred storm expense regulatory assets (the remaining unamortized balance authorized in Case No. 2012-00445 and the amount

authorized in Case No. 2016-00180) will total $10,464,336 on December 31, 2017 and will be amortized over five years at an annual amount of $2,092,867.

10. Kentucky Economic Development Surcharge

(a) Kentucky Power's new Kentucky Economic Development Surcharge Tariff ("Tariff K.E.D.S.") shall be approved with rates amended as follows:

(i) The KEDS rate for residential customers will be set at $0.10 per meter instead of $0.25 as proposed by the Company.

(ii) The KEDS rate for non-residential customers for which the KEDS applies will be set at $1.00 per meter instead of $0.25 as proposed by the Company.

(b) All KEDS funds collected by Kentucky Power shall be matched dollar-for-dollar by Kentucky Power from shareholder funds. The proceeds of KEDS and Kentucky Power's shareholder contribution shall be used by Kentucky Power for economic development projects, including the training of local economic development officials, in the Company's service territory. The KEDS, and the matching shareholder contribution, shall remain in effect until changed by order of the Commission.

(c) Kentucky Power will continue to file on or before March 31st of each year a report with the Commission describing: (i) the amount collected through the Economic Development Surcharge; and (ii) the matching amount contributed by Kentucky Power from shareholder funds. The annual report to be filed by the Company shall also describe the amount, recipients, and purposes of its expenditure of the funds collected through the Economic Development Surcharge and shareholder contribution.

(d) Kentucky Power shall serve a copy of the annual report to be filed with the Commission in accordance with subparagraph (c) on counsel for all parties to this proceeding.

11. Backup and Maintenance Service

(a) In order for Marathon Petroleum LP ("Marathon") to evaluate the economics of self or co-generation, Kentucky Power and Marathon will begin negotiations regarding the terms, conditions and pricing for backup and maintenance service within 30 days of a Commission Order approving this provision and will complete negotiations within the next 120 days. Prior to the start of the 120 day negotiation period, Marathon will provide Kentucky Power with specific information regarding the MW size of a potential self or co-generation facility and the type of generation technology being considered.

(b) If Kentucky Power and Marathon cannot reach an agreement on backup and maintenance service within 120 days, Kentucky Power and Marathon agree to submit the issue to the Commission for resolution.

12. School Energy Manager Program

(a) Kentucky Power shall seek leave from the Commission to include up to $200,000 for the School Energy Manager Program in its each of its 2018 and 2019 DSM Program offerings.

(b) Kentucky Power and KSBA both expressly acknowledge that there is in Case No. 2017-00097 a currently-pending Commission investigation of the Company's DSM programs and funding and that the outcome of that investigation could impact the School Energy Manager Program.

13. Tariff K-12 School

(a) Kentucky Power shall continue its current Pilot Tariff K-12 School but shall remove the Pilot designation as set forth in **Exhibit 7**. Tariff K-12 School shall be available for general service to all K-12 schools in the Company's service territory, public and private, with normal maximum demands greater than 100 kW. Tariff K-12 School shall reflect rates for

customers taking service under the tariff designed to produce annually in the aggregate $500,000 less from Tariff K-12 School customers than would be produced under the new L.G.S. rates to be established under this Settlement Agreement from customers eligible to take service under Tariff K-12 School. The aggregate total revenues to be produced by Tariff K-12 School and Tariff L.G.S. shall be equal to the revenues that would be produced in the aggregate by the new rates in the absence of Tariff K-12 School. Service under Tariff K-12 School shall be optional.

14. Bill Format Changes

(a) The bill formatting changes proposed by the Company in Case No. 2017-00231 and consolidated into this case by Commission Order dated July 17, 2017, to the extent not already approved, are approved.

(b) Within 180 days of a Commission Order approving this Settlement, Kentucky Power will conduct a training session with representatives from its municipal clients and KLC to explain the new bill format and tools available to clients to evaluate their electric usage.

15. Renewable Power Option Rider

(a) The proposed changes to the Company's Green Pricing Option Rider, including renaming the rider to the Renewable Power Option Rider ("Rider R.P.O."), are approved except that the availability of service provision for Option B will state the following:

> "Customers who wish to directly purchase the electrical output and all associated environmental attributes from a renewable energy generator may contract bilaterally with the Company under Option B. Option B is available to customers taking metered service under the Company's I.G.S., and C.S.-I.R.P. tariffs, or multiple L.G.S. tariff accounts with common ownership under a single parent company that can aggregate multiple accounts to exceed 1000 kW of peak demand."

A revised version of Rider R.P.O. incorporating the modifications described above is included as EXHIBIT 8. Bills for customers receiving service under Rider R.P.O. will include a separate line item for Rider R.P.O. charges.

(b) Beginning no later than March 31, 2018, and no later than each March 31 thereafter, Kentucky Power will file a report with the Commission describing the previous year's activity under Rider R.P.O. This annual report will replace the semi-annual reports filed in Case No. 2008-00151.

16. Modifications To Kentucky Power's Rate Tariffs

In addition to the rate and tariff changes described and agreed to above, Kentucky Power and the Settling Intervenors agree that the following tariffs shall be modified or implemented as described below:

(a) The Customer charge for the Residential Class ("Tariff R.S.") shall be increased to $14.00 per month instead of the $17.50 per month proposed by the Company in its filing in this case.

(b) The Company is extending the termination date for Tariff C.S. – Coal and the amendments to Tariff C.S. – I.R.P. and Tariff E.D.R. approved in Case No. 2017-00099 from December 31, 2017 to December 31, 2018.

(c) The pole attachment rate under Tariff C.A.T.V. shall be $10.82 for attachments on two-user poles and $6.71 for attachments on three-user poles for all attachments instead of the $11.97 for attachments on two-user poles and $7.42 for attachments on three-user poles proposed by the Company in its filing in this case.

17. Filing Of Settlement Agreement With The Commission And Request For Approval

Following the execution of this Settlement Agreement, Kentucky Power and the Settling Intervenors shall file this Settlement Agreement with the Commission along with a joint request to the Commission for consideration and approval of this Settlement Agreement so that Kentucky

Power may begin billing under the approved adjusted rates for service rendered on or before January 19, 2018.

18. Good Faith And Best Efforts To Seek Approval

(a) This Settlement Agreement is subject to approval by the Public Service Commission.

(b) Kentucky Power and the Settling Intervenors shall act in good faith and use their best efforts to recommend to the Commission that this Settlement Agreement be approved in its entirety and without modification and that the rates and charges set forth herein be implemented.

(c) Kentucky Power and the Settling Intervenors filed testimony in this case. Kentucky Power also filed testimony in support of the Settlement Agreement. For purposes of any hearing, the Settling Intervenors and Kentucky Power waive all cross-examination of the other Signatory Parties' witnesses except for purposes of supporting this Settlement Agreement unless the Commission disapproves this Settlement Agreement. Each further stipulates and recommends that the Notice of Intent, Application, testimony, pleadings, and responses to data requests filed in this proceeding be admitted into the record.

(d) The Signatory Parties further agree to support the reasonableness of this Settlement Agreement before the Commission, and to cause their counsel to do the same, including in connection with any appeal from the Commission's adoption or enforcement of this Settlement Agreement.

(e) No party to this Settlement Agreement shall challenge any Order of the Commission approving the Settlement Agreement in its entirety and without modification.

19. Failure Of Commission To Approve Settlement Agreement

If the Commission does not accept and approve this Stipulation in its entirety, then any adversely affected Party may withdraw from the Stipulation within the statutory periods provided for rehearing and appeal of the Commission's order by (1) giving notice of withdrawal to all other Parties and (2) timely filing for rehearing or appeal. Upon the latter of (1) the expiration of the statutory periods provided for rehearing and appeal of the Commission's order and (2) the conclusion of all rehearing's and appeals, all Parties that have not withdrawn will continue to be bound by the terms of the Stipulation as modified by the Commission's order.

20. Continuing Commission Jurisdiction

This Settlement Agreement shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

21. Effect of Settlement Agreement

This Settlement Agreement shall inure to the benefit of, and be binding upon, the parties to this Settlement Agreement, their successors, and assigns.

22. Complete Agreement

This Settlement Agreement constitutes the complete agreement and understanding among the parties to this Settlement Agreement, and any and all oral statements, representations, or agreements. Any and all such oral statements, representations, or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into this Settlement Agreement.

23. Independent Analysis

The terms of this Settlement Agreement are based upon the independent analysis of the parties to this Settlement Agreement, are the product of compromise and negotiation, and reflect a fair, just, and reasonable resolution of the issues herein. Notwithstanding anything contained in this Settlement Agreement, Kentucky Power and the Settling Intervenors recognize and agree that the effects, if any, of any future events upon the income of Kentucky Power are unknown and this Settlement Agreement shall be implemented as written.

24. Settlement Agreement And Negotiations Are Not An Admission

(a) This Settlement Agreement shall not be deemed to constitute an admission by any party to this Settlement Agreement that any computation, formula, allegation, assertion, or contention made by any other party in these proceedings is true or valid. Nothing in this Settlement Agreement shall be used or construed for any purpose to imply, suggest or otherwise indicate that the results produced through the compromise reflected herein represent fully the objectives of the Signatory Parties.

(b) Neither the terms of this Settlement Agreement nor any statements made or matters raised during the settlement negotiations shall be admissible in any proceeding, or binding on any of the parties to this Settlement Agreement, or be construed against any of the parties to this Settlement Agreement, **except that** in the event of litigation or proceedings involving the approval, implementation or enforcement of this Agreement, the terms of this Settlement Agreement shall be admissible. This Settlement Agreement shall not have any precedential value in this or any other jurisdiction.

25. Consultation With Counsel

The parties to this Settlement Agreement warrant that they have informed, advised, and consulted with their respective counsel with regard to the contents and significance of this Settlement Agreement and are relying upon such advice in entering into this agreement.

26. Authority To Bind

Each of the signatories to this Settlement Agreement hereby warrant they are authorized to sign this agreement upon behalf of, and bind, their respective parties.

27. Construction Of Agreement

This Settlement Agreement is a product of negotiation among all parties to this Settlement Agreement, and no provision of this Settlement Agreement shall be construed in favor of or against any party hereto. This Settlement Agreement is submitted for purposes of this case only and is not to be deemed binding upon the parties hereto in any other proceeding, nor is it to be offered or relied upon in any other proceeding involving Kentucky Power or any other utility.

28. Counterparts

This Settlement Agreement may be executed in multiple counterparts.

29. Future Rate Proceedings

Nothing in this Settlement Agreement shall preclude, prevent, or prejudice any party to this Settlement Agreement from raising any argument or issue, or challenging any adjustment, in any future rate proceeding of Kentucky Power.

IN WITNESS WHEREOF, this Settlement Agreement has been agreed to as of this 22nd day of November 2017.

KENTUCKY POWER COMPANY

By: ____________________

Its: Counsel

KENTUCKY INDUSTRIAL UTILITY
CUSTOMERS, INC.

By: Michael L. Kurtz

Its: Counsel

KENTUCKY SCHOOL BOARDS
ASSOCIATION, INC.

By: Matthew Malone

Its: Legal Counsel

KENTUCKY LEAGUE OF CITIES

By: [signature]

Its: Director of Municipal Law & Training

KENTUCKY CABLE
TELECOMMUNICATION
ASSOCIATION, INC.

By: Jason K[illegible]

Its: KCTA Board Chairman

WAL-MART STORES EAST, LP AND
SAM'S EAST, INC.

By: ______________________

Its: Counsel

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00179 DATED JAN 18 2018

Adjustments	Amounts
Capacity Charge Revenues Removal	($6,396,832)
Removal of Effects of Decommissioning Rider Revenue and Expenses	($18,512,331)
Eliminate Mitchell FGD Operating Expenses	($13,308,197)
Remove Mitchell plant FGD and Consumable inventory from Rate Base	($1,610,192)
Removal of Mitchell FGD Environmental Surcharge Rider Revenues	($538,417)
Remove Big Sandy Unit 1 Operation Rider Deferrals	($4,333,902)
Fuel Under (Over) Revenues	$4,574,472
Reset OSS Margin Baseline to 2016 Test Year OSS Margins	($8,800,856)
PPA Rider Synchronization Adjustment	$372,542
Remove DSM Revenue Expense	($5,503,380)
Remove HEAP Revenue and Expense	($246,772)
Remove Economic Development Surcharge Revenue and Expense	($303,011)
Tariff Migration Adjustment	$1,026,263
Customer Annualization Revenue Adjustment	($1,342,364)
Weather Normal Load Revenue Adjustment	$4,080,748
O&M Expense Interest on Customer Deposit	$67,254
Amortization of Major Storm Cost Deferral	$874,592
Postage Rate Decrease Adjustment	($6,656)
Eliminate Advertising Expense	$100,444
Adjust Pension and OPEB Expense	$148,679
Employee Related Group Benefit Expense	$429,241
Remove PJM BLIs From Base for FAC Inclusions	($516,659)
Adjustment to Include Purchase Power Limitation Expense in Rate Base	$3,150,582
Adjustment to Include Forced Outage Purchase Power Limitation in Base Rates	$882,204
Annualize NITS/PJM LSE OATT Expense	$3,825,858
Annualize PJM Admin Charges	$118,606
Amortization of NERC Cost Deferral	$14,275
Severance Expense Adjustment	$2,363
Annualization of Payroll Expense Adjustment	$244,837
Social Security Tax Base Adjustment	$26,009
Eliminate Non-Recoverable Business Expenses	$14,914
Plant Maintenance Normalization	($274,334)
Depreciation Annualization Adjustment Electric Plant in Service	$2,037,359
Decrease ARO Depreciation Expense to an Annualized Level	($3,818)
Decrease ARO Accretion Expense to an Annualized Level	($109,495)
Annualization of Cable Pole Attachment Revenue	$532,369
KPSC Maintenance Assessment	($1,801)
State Gross Receipts Tax Adjustment	$78,776

Interest Synchronization Adjustment (Per 8/7/2017 Amendment)	$6,449,828
AFUDC Offset Adjustment (Per 8/17/2017 Amendment)	$28,197
Adjustment to Recognize Accrued Surcharge Revenue Differences	($62,588)
Mitchell Plant ADSIT Amortization	$1,292,491
Decrease O&M for Vegetation Management Tree Trimming	($6,794,282)
Annualization of Property Taxes	$595,507

APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00179 DATED JAN 18 2018

The following rates and charges are prescribed for the customers in the area served by Kentucky Power Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

TARIFF R.S.
RESIDENTIAL SERVICE

Service Charge per month	$	14.00
Energy Charge per kWh	$	.09660
Storage Water Heating Provision - Per kWh	$	.06072
Load Management Water Heating Provision - Per kWh	$	.06072
Home Energy Assistance Program Charge Per meter per month	$	.30

TARIFF R.S.-L.M.-T.O.D.
RESIDENTIAL SERVICE LOAD MANAGEMENT TIME-OF-DAY

Service Charge per month	$	16.00
Energy Charge per kWh:		
All kWh used during on-peak billing period	$	.14346
All kWh used during off-peak billing period	$	.06072
Separate Metering Provision Per Month	$	3.75
Home Energy Assistance Program Charge Per meter per month	$	.30

TARIFF R.S.-T.O.D.
RESIDENTIAL SERVICE TIME-OF-DAY

Service Charge per month	$	16.00
Energy Charge per kWh:		
All kWh used during on-peak billing period	$	.14386
All kWh used during off-peak billing period	$	.06072
Home Energy Assistance Program Charge Per meter per month	$	.30

TARIFF R.S.-T.O.D. 2
EXPERIMENTAL RESIDENTIAL SERVICE TIME-OF-DAY 2

Service Charge per month	$	16.00
Energy Charge per kWh:		
All kWh used during summer on-peak billing period	$	.17832
All kWh used during winter on-peak billing period	$	.15342
All kWh used during off-peak billing period	$	.08094
Home Energy Assistance Program Charge		
Per meter per month	$	.30

TARIFF R.S.D.
RESIDENTIAL DEMAND-METERED ELECTRIC SERVICE

Service Charge per month	$	17.50
Energy Charge per kWh:		
All kWh used during on-peak billing period	$	.09738
All kWh used during off-peak billing period	$	.07029
Demand Charge per kW	$	4.02
Home Energy Assistance Program Charge		
Per meter per month	$	.30

TARIFF G.S.
GENERAL SERVICE

Secondary Service:		
Service Charge per month	$	22.50
Energy Charge per kWh:		
Phase 1		
First 4,450 kWh per month	$	.10198
Over 4,450 kWh per month	$	.10188
Phase 2		
First 4,450 kWh per month	$	.09807
Over 4,450 kWh per month	$	.09798
Demand Charge per kW greater than 10 kW		
Phase 1	$	4.00
Phase 2	$	6.00
Primary Service:		
Service Charge per month	$	75.00
Energy Charge per kWh:		
First 4,450 kWh per month	$	.08629
Over 4,450 kWh per month	$	.08659
Demand Charge per kW greater than 10 kW	$	7.18

Subtransmission Service:

Service Charge per month	$ 364.00
Energy Charge per kWh:	
First 4,450 kWh per month	$ .07822
Over 4,450 kWh per month	$ .07855
Demand Charge per kW greater than 10 kW	$ 5.74

TARIFF G.S.
GENERAL SERVICE
RECREATIONAL LIGHTING SERVICE PROVISION

Service Charge per month	$ 22.50
Energy Charge per kWh	$ .09968

TARIFF G.S.
GENERAL SERVICE
LOAD MANAGEMENT TIME-OF-DAY PROVISION

Service Charge per month	$ 22.50
Energy Charge per kWh:	
All kWh used during on-peak billing period	$ .14423
All kWh used during off-peak billing period	$ .06072

TARIFF G.S.
GENERAL SERVICE
OPTIONAL UNMETERED SERVICE PROVISION

Service Charge per month	$ 14.00
Energy Charge per kWh:	
Phase 1	
First 4,450 kWh per month	$ .10198
Over 4,450 kWh per month	$ .10188
Phase 2	
First 4,450 kWh per month	$ .09807
Over 4,450 kWh per month	$ .09798

TARIFF S.G.S.-T.O.D.
SMALL GENERAL SERVICE TIME-OF-DAY

Service Charge per month	$ 22.50
Energy Charge per kWh:	
All kWh used during summer on-peak billing period	$ .17034
All kWh used during winter on-peak billing period	$ .14372
All kWh used during off-peak billing period	$ .07511

TARIFF M.G.S.-T.O.D.
MEDIUM GENERAL SERVICE TIME-OF-DAY

Service Charge per month	$ 22.50
Energy Charge per kWh:	
All kWh used during on-peak billing period	$ .16747
All kWh used during off-peak billing period	$ .06072

TARIFF L.G.S.
LARGE GENERAL SERVICE

Secondary Service Voltage:	
Service Charge per month	$ 85.00
Energy Charge per kWh	$ .07712
Demand Charge per kW	$ 7.97
Primary Service Voltage:	
Service Charge per month	$ 127.50
Energy Charge per kWh	$ .06711
Demand Charge per kW	$ 7.18
Sub-transmission Service Voltage:	
Service Charge per month	$ 660.00
Energy Charge per kWh	$ .05112
Demand Charge per kW	$ 5.74
Transmission Service Voltage:	
Service Charge per month	$ 660.00
Energy Charge per kWh	$ .04997
Demand Charge per kW	$ 5.60
All Service Voltages:	
Excess Reactive Charge per KVA	$ 3.46

TARIFF L.G.S.
LARGE GENERAL SERVICE
LOAD MANAGEMENT TIME-OF-DAY PROVISION

Service Charge per month	$ 85.00
Energy Charge per kWh:	
All kWh used during on-peak billing period	$ .14063
All kWh used during off-peak billing period	$ .06088

TARIFF L.G.S. – T.O.D.
LARGE GENERAL SERVICE TIME-OF-DAY

Secondary Service Voltage:	
Service Charge per month	$ 85.00
Energy Charge:	
On-Peak Energy Charge per kWh	$ .09670
Off-Peak Energy Charge per kWh	$ .04132
Demand Charge per kW	$ 10.87
Primary Service Voltage:	
Service Charge per month	$ 127.50
Energy Charge:	
On-Peak Energy Charge per kWh	$ .09300
Off-Peak Energy Charge per kWh	$ .04010
Demand Charge per kW	$ 7.84
Sub-transmission Service Voltage:	
Service Charge per month	$ 660.00
Energy Charge:	
On-Peak Energy Charge per kWh	$ .09176
Off-Peak Energy Charge per kWh	$ .03970
Demand Charge per kW	$ 1.52
Transmission Service Voltage:	
Service Charge per month	$ 660.00
Energy Charge:	
On-Peak Energy Charge per kWh	$ .09049
Off-Peak Energy Charge per kWh	$ .03928
Demand Charge per kW	$ 1.49
All Service Voltages:	
Excess Reactive Charge per KVA	$ 3.46

TARIFF I.G.S.
INDUSTRIAL GENERAL SERVICE

Secondary Service Voltage:	
Service Charge per month	$ 276.00
Energy Charge per kWh	$ .02663
Demand Charge per kW	
Of Monthly On-Peak Billing Demand	$ 24.13
Of Monthly Off-Peak Billing Demand	$ 1.60

Primary Service Voltage:	
Service Charge per month	$ 276.00
Energy Charge per kWh	$ .02553
Demand Charge per kW	
Of Monthly On-Peak Billing Demand	$ 20.57

Sub-transmission Service Voltage:	
Service Charge per month	$ 794.00
Energy Charge per kWh	$ .02793
Demand Charge per kW	
Of Monthly On-Peak Billing Demand	$ 13.69
Of Monthly Off-Peak Billing Demand	$ 1.51

Transmission Service Voltage:	
Service Charge per month	$1,353.00
Energy Charge per kWh	$ .02792
Demand Charge per kW	
Of Monthly On-Peak Billing Demand	$ 13.26
Of Monthly Off-Peak Billing Demand	$ 1.49

All Service Voltages:
Reactive demand charge for each kilovar of maximum leading or lagging reactive demand in excess of 50 percent of the kW of monthly metered demand is $.69 per KVAR.

Minimum Demand Charge
The minimum demand charge shall be equal to the minimum billing demand times the following minimum demand rates per kW:

Secondary	$ 25.83
Primary	$ 22.21
Subtransmission	$ 15.30
Transmission	$ 14.86

TARIFF M.W.
MUNICIPAL WATERWORKS

Service Charge per month	$ 22.90
Energy Charge - All kWh per kWh	$ .09135

Subject to a minimum monthly charge equal to the sum of the service charge plus $8.89 per kW as determined from customer's total connected load.

TARIFF O.L.
OUTDOOR LIGHTING

OVERHEAD LIGHTING SERVICE

High Pressure Sodium per Lamp:		
100 Watts (9,500 Lumens)	$	8.50
150 Watts (16,000 Lumens)	$	9.30
200 Watts (22,000 Lumens)	$	10.90
250 Watts (28,000 Lumens)	$	15.04
400 Watts (50,000 Lumens)	$	16.01
Mercury Vapor per Lamp:		
175 Watts (7,000 Lumens)	$	9.04
400 Watts (20,000 Lumens)	$	14.64

POST-TOP LIGHTING SERVICE

High Pressure Sodium per Lamp:		
100 Watts (9,500 Lumens)	$	14.05
150 Watts (16,000 Lumens)	$	23.30
100 Watts Shoe Box (9,500 Lumens)	$	29.50
250 Watts Shoe Box (28,000 Lumens)	$	24.99
400 Watts Shoe Box (50,000 Lumens)	$	36.16
Mercury Vapor per Lamp:		
175 Watts (7,000 Lumens)	$	10.59

FLOOD LIGHTING SERVICE

High Pressure Sodium per Lamp:		
200 Watts (22,000 Lumens)	$	13.10
400 Watts (50,000 Lumens)	$	17.06
Metal Halide		
250 Watts (20,500 Lumens)	$	15.27
400 Watts (36,000 Lumens)	$	18.39
1,000 Watts (110,000 Lumens)	$	30.94
250 Watts Mongoose (19,000 Lumens)	$	20.57
400 Watts Mongoose (40,000 Lumens)	$	23.59

Per Month:		
Wood Pole	$	3.40
Overhead Wire Span not over 150 Feet	$	2.00
Underground Wire Lateral not over 50 Feet	$	7.40

Per Lamp plus $0.02725 x kWh in Sheet No. 14-3 in Company's tariff

TARIFF S.L.
STREET LIGHTING

Rate per Lamp:
Overhead Service on Existing Distribution Poles

High Pressure Sodium		
100 Watts (9,500 Lumens)	$	7.02
150 Watts (16,000 Lumens)	$	7.55
200 Watts (22,000 Lumens)	$	8.95
400 Watts (50,000 Lumens)	$	11.71

Service on New Wood Distribution Poles

High Pressure Sodium		
100 Watts (9,500 Lumens)	$	10.80
150 Watts (16,000 Lumens)	$	11.55
200 Watts (22,000 Lumens)	$	12.95
400 Watts (50,000 Lumens)	$	16.61

Service on New Metal or Concrete Poles

High Pressure Sodium		
100 Watts (9,500 Lumens)	$	27.45
150 Watts (16,000 Lumens)	$	28.15
200 Watts (22,000 Lumens)	$	26.70
400 Watts (50,000 Lumens)	$	27.11

Per Lamp plus $0.02725 x kWh in Sheet No. 15-2 in Company's tariff

TARIFF C.A.T.V.
CABLE TELEVISION POLE ATTACHMENT

Charge for attachments

On a two-user pole	$	10.82
On a three-user pole	$	6.71

TARIFF COGEN/SPP I
COGNERATION AND/OR SMALL POWER PRODUCTION
100 KW OR LESS

Monthly Metering Charges:
Single Phase:

Standard Measurement	$	9.25
Time-of-Day Measurement	$	9.85

Polyphase:		
Standard Measurement	$	12.10
Time-of-Day Measurement	$	12.40
Energy Credit per kWh:		
Standard Meter – All kWh	$	.03240
Time-of-Day Meter:		
On-Peak kWh	$	.03860
Off-Peak kWh	$	.02790
Capacity Credit:		
Standard Meter per kW	$	3.11
Time-of-Day Meter per kW	$	7.47

TARIFF COGEN/SPP II
COGNERATION AND/OR SMALL POWER PRODUCTION OVER 100 KW

Metering Charges:		
Single Phase:		
Standard Measurement	$	9.25
Time-of-Day Measurement	$	9.85
Polyphase:		
Standard Measurement	$	12.10
Time-of-Day Measurement	$	12.40
Energy Credit per kWh:		
Standard Meter – All kWh	$	.03240
Time-of-Day Meter:		
On-Peak kWh	$	.03860
Off-Peak kWh	$	.02790
Capacity Credit:		
Standard Meter per kW	$	3.11
Time-of-Day Meter per kW	$	7.47

TARIFF K.E.D.S.
KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE

Per month per account:		
Residential	$	.00
All Other	$	1.00

TARIFF C.C.
CAPACITY CHARGE

Energy Charge per kWh:		
Service Tariff		
I.G.S.	$	.000749
All Other	$	.001435

RIDER R.P.O.
RENEWABLE POWER OPTION RIDER
OPTION A

Solar RECs:		
Block Purchase per 100 kWh per month	$	1.00
All Usage Purchase per kWh consumed	$	.01000
Wind RECs:		
Block Purchase per 100 kWh per month	$	1.00
All Usage per kWh consumed	$	.01000
Hydro & Other RECs:		
Block Purchase per 100 kWh per month	$	.30
All Usage per kWh consumed	$	.00300

RIDER A.F.S.
ALTERNATE FEED SERVICE RIDER

Monthly Rate for Annual Test of Transfer Switch/Control Module	$	14.67
Monthly Capacity Reservation Demand Charge per kW	$	6.29

APPENDIX D

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00179 DATED JAN 18 2018

ENVIRONMENTAL COMPLIANCE PLAN

Project	Plant	Pollutant	Description	In-Service Year
			Previously Approved Environmental Compliance Projects	
1	Mitchell	NOx, SO2, and SO3	Mitchell Units 1 & 2, Water Injection, Low NOx Burners, Low NOx Burner Modification, SCR, FGD, Landfill, Coal Blending Facilities & SO3 Mitigation	1993-1994-2002-2007
2	Mitchell	SO2, NOx and Gypsum	Mitchell Plant Common CEMS, Replace Burner Barrier Valves & Gypsum Material Handling Facilities	1993-1994-2007
3	Rockport	SO2 / NOx	Continuous Emission Monitors ("CEMS")	1994
4	Rockport	NOx, Fly Ash, & Bottom Ash	Rockport Units 1 & 2 Low NOx Burners, Over Fire Air & Landfill	2003-2008
5	Mitchell & Rockport	SO2, NOx, Particulates & VOC and etc.	Title V Air Emissions Fees at Mitchell and Rockport Plants	Annual
6	Big Sandy, Mitchell & Rockport	NOx	Costs Associated with NOx Allowances	As Needed
7	Big Sandy, Mitchell & Rockport	SO2	Costs Associated with SO2 Allowances	As Needed
8	Big Sandy, Mitchell & Rockport	SO2 / NOx	Costs Associated with the CSAPR Allowances	As Needed
9	Mitchell	Particulates	Mitchell Units 1 & 2 - Precipitator Modifications	2007-2013
10	Mitchell	Particulates	Mitchell Units 1 & 2 - Bottom Ash & Fly Ash Handling	2008-2010
11	Mitchell	Mercury	Mitchell Units 1 & 2 - Mercury Monitoring ("MATS")	2014
12	Mitchell	Selenium	Mitchell Units 1 & 2 - Dry Fly Ash Handling Conversion	2014
13	Mitchell	Fly Ash, Bottom Ash, Gypsum & WWTP Solids	Mitchell Units 1 & 2 - Coal Combustion Waste Landfill	2014
14	Mitchell	Particulates	Mitchell Unit 2 - Electrostatic Precipitator Upgrade	2015
15	Rockport	Particulates	Rockport Units 1 & 2 - Precipitator Modifications	2004-2009
16	Rockport	Mercury	Rockport Units 1 & 2 - Activated Carbon Injection ("ACI") & Mercury Monitoring	2009-2010

17	Rockport	Hazardous Air Pollutants ("HAPS")	Rockport Units 1 & 2 - Dry Sorbent Injection	2015
18	Rockport	Fly Ash & Bottom Ash	Rockport Plant Common - Coal Combustion Waste Landfill Upgrade to Accept Type 1 Ash	2013 & 2015
			Proposed Environmental Compliance Projects	
19	Rockport	NOx	Rockport Unit 1 - Selective Catalytic Reduction equipment	2017
20	Mitchell Rockport	SO2 / NOx, Mercury, Particulates, Hazardous Air Pollutants ("HAPS")	Cost of consumables used in conjunction with approved ECP projects including the cost of the consumables used and a return on consumable inventories. Consumables include, but are not limited to sodium bicarbonate, activated carbon, anhydrous ammonia, trona, lime hydrate, limestone, polymer, and urea.	As Needed

APPENDIX E

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00179 DATED JAN 18 2018

MONTHLY BASE PERIOD REVENUE REQUIREMENT

Billing Month	Base Period Cost
January	$ 3,664,681
February	3,581,017
March	3,353,024
April	3,661,574
May	3,595,145
June	3,827,332
July	3,747,320
August	3,888,262
September	3,636,247
October	3,824,697
November	3,717,340
December	3,882,677
	$ 44,379,316

APPENDIX F

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00179 DATED JAN 18 2018

Commission Staff Adjustments to the Revenue Requirement in the Settlement Agreement
Case No. 2017-00179
Kentucky Power Company (Kentucky Jurisdiction)

	Pre-Tax Operating Income Amount	NOI Amount	GRCF		Staff RR Amount
Increase Per Settlement					31,780,734
Operating Income Issues					
OSS Rider Adjustment	(486,412)	(361,693)	1.352116	$	(489,051)
Theft Recovery Revenue	(166,198)	(123,584)	1.352116	$	(167,100)
Purchased Power Adj (WP 26&27)	(4,032,786)	(2,998,755)	1.352116	$	(4,054,664)
Relocation Expense	(132,109)	(98,235)	1.352116	$	(132,826)
Cost of Capital Issues					
Total Change in ROE and capitalization		(476,714)	1.352116	$	(644,573)
Change in GCRF					(13,943,890)
Total Adjustments to the Settlement Agreement				$	(19,432,104)
Recommended Change in Base Rates				$	12,348,630

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EXHIBIT B

EXHIBIT MJS-1S

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets Or Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)	Case No. 2017-00179

SETTLEMENT AGREEMENT

This Settlement Agreement, made and entered into this 22nd day of November, 2017, by and among Kentucky Power Company ("Kentucky Power" or "Company"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Kentucky School Boards Association ("KSBA"); Kentucky League of Cities ("KLC"); Wal-Mart Stores East, LP and Sam's East, Inc. ("Wal-Mart"); and Kentucky Cable Telecommunications Association ("KCTA"); (collectively Kentucky Power, KIUC, KSBA, KLC, Wal-Mart, and KCTA, are "Signatory Parties").

RECITALS

1. On June 28, 2017 Kentucky Power filed an application pursuant to KRS 278.190, KRS 278.183, and the rules and regulations of the Public Service Commission of Kentucky ("Commission"), seeking an annual increase in retail electric rates and charges totaling \$69,575,934, seeking approval of its 2017 Environmental Compliance Plan, an order approving accounting practices to establish regulatory assets or liabilities, and further seeking authority to implement or amend certain tariffs ("June 2017 Application").

2. On August 8, 2017, Kentucky Power supplemented its filing to reflect the impact of subsequent refinancing activities on the Company's Application ("August 2017 Refinancing Update"). The refinancing activities reduced the Company's requested annual increase in retail electric rates and charges from $69,575,934 to $60,397,438.

3. KIUC, KSBA, KLC, Wal-Mart, and KCTA filed motions for full intervention in Case No. 2017-00179. The Commission granted the intervention motions. Collectively KIUC, KSBA, KLC, Wal-Mart, and KCTA are referred to in this Settlement Agreement as the "Settling Intervenors."

4. The Attorney General of the Commonwealth of Kentucky ("Attorney General") and Kentucky Commercial Utility Customers, Inc. ("KCUC") also filed motions to intervene. The Attorney General and KCUC, who are not parties to this agreement, were granted leave to intervene.

5. Certain of the Settling Intervenors, KCUC, and the Attorney General filed written testimony in Case No. 2017-00179 raising issues regarding Kentucky Power's Rate Application.

6. Kentucky Power, KCUC, the Attorney General, and the Settling Intervenors have had a full opportunity for discovery, including the filing of written data requests and responses.

7. Kentucky Power offered the Settling Intervenors, KCUC, and the Attorney General, along with Commission Staff, the opportunity to meet and review the issues presented by Kentucky Power's application in this proceeding and for purposes of settlement.

8. The Signatory Parties execute this Settlement Agreement for purposes of submitting it to the Kentucky Public Service Commission for approval pursuant to KRS 278.190 and KRS 278.183 and for further approval by the Commission of the rate increase, rate structure, and tariffs as described herein.

9. The Signatory Parties believe that this Settlement Agreement provides for fair, just, and reasonable rates.

NOW, THEREFORE, for and in consideration of the mutual promises set forth above, and the agreements and covenants set forth herein, Kentucky Power and the Settling Intervenors hereby agree as follows:

AGREEMENT

1. Kentucky Power's Application

(a) Except as modified in this Settlement Agreement, Kentucky Power's June 2017 Application as updated by the August 2017 Refinancing Update is approved.

2. Revenue Requirement

(a) Effective for service rendered on or after January 19, 2018, Kentucky Power shall implement a base rate adjustment sufficient to generate additional annual retail revenues of $31,780,734. This annual retail revenue amount represents a $28,616,704 million reduction from the $60,397,438 sought in the Company's August 2017 Refinancing Update.

(b) The $28,616,704 million reduction was the result of the following adjustments to the Company's request in the June 2017 Rate Application as modified in the August 2017 Refinancing Update:

Adjustment	Reduction in Revenue Requirement ($Millions)
Defer a portion of Rockport UPA non-fuel, non-environmental expenses	15.0
Increase revenues to Apply Weather Normalization to Commercial Sales Net of Variable O&M	0.40
Reduce Incentive Compensation	3.15
Reduce Amortization Expense to Recalibrate Storm Damage Amortization	1.22

Reduce Depreciation Expense by Extending Service Life of BS1 to 20 years	2.84
Reduce Depreciation Expense by Removing Terminal Net Salvage for BSU1	0.37
Reduce Depreciation Expense by Removing Terminal Net Salvage for Mitchell	0.57
Increase Short Term Debt to 1% and Set Debt Rate at 1.25%	0.36
Change in Return on Equity from 10.31% to 9.75%	4.70
Total Adjustments	**28.6**

(c) Kentucky Power agrees to allocate the $31,780,734 in additional annual revenue as illustrated on **EXHIBIT 1.** The Company will design rates and tariffs consistent with this allocation of additional revenue.

(i) As part of the Commission's consideration of the reasonableness of this Settlement Agreement, the tariffs designed in accordance with this subparagraph shall be filed with the Commission and served on counsel for all parties to this case no later than December 1, 2017.

(ii) Within ten days of the entry of the Commission's Order approving without modification this Settlement Agreement and the rates thereunder, Kentucky Power shall file with the Commission signed copies of the tariffs in conformity with 807 KAR 5:011.

3. Rockport UPA Expense Deferral

(a) Kentucky Power is a party to a FERC-approved Unit Power Agreement with AEP Generating Company for capacity and energy produced at the Rockport Plant ("Rockport UPA"). The Rockport UPA expires on December 8, 2022.

(b) Kentucky Power will defer a total of $50 million in non-fuel, non-environmental Rockport UPA Expense for later recovery as follows:

(i) Kentucky Power will defer $15M annually of Rockport UPA Expense in 2018 and 2019 for later recovery.

(ii) Kentucky Power will defer $10M of Rockport UPA Expense in 2020 for later recovery.

(iii) Kentucky Power will defer $5M annually of Rockport UPA Expense in years 2021 and 2022 for later recovery.

(c) The Rockport UPA Expense of $50 million described in Paragraph 3(b) above will be deferred into a regulatory asset ("the Rockport Deferral Regulatory Asset") and will be subject to carrying charges based on a weighted average cost of capital ("WACC") of 9.11%[1] until the Regulatory Asset is fully recovered. From January 1, 2018 through December 8, 2022, the WACC will be applied to the monthly Rockport Deferral Regulatory Asset principal balance net of accumulated deferred income taxes ("ADIT"). From December 9, 2022 until the Rockport Deferral Regulatory Asset is fully recovered, the WACC will be applied to the monthly Rockport Deferral Regulatory Asset balance including deferred carrying charges net of ADIT. The Rockport Deferral Regulatory Asset shall be recovered on a levelized basis through the demand component of Tariff P.P.A. and amortized over five years beginning on December 9, 2022. Kentucky Power estimates that the regulatory asset balance will total approximately $59 million on December 8, 2022.

(d) Additional expenses reflecting the declining deferral amount in years 2020 through 2022 will be recovered through the demand component of Tariff P.P.A. as follows:

(i) Kentucky Power will recover $5 million through Tariff P.P.A. in 2020

(ii) Kentucky Power will recover $10 million through Tariff P.P.A. in 2021

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[1] 6.48% grossed up for applicable State and Federal taxes, uncollectible accounts expense, and the KPSC maintenance fee

(iii) Kentucky Power will recover $10 million through Tariff P.P.A. in 2022, prorated through December 8, 2022.

(e) The Signatory Parties acknowledge that the Company's decision whether to seek Commission approval to extend the Rockport UPA will be made at a later date. Whether or not the Company seeks to extend the Rockport UPA, beginning December 9, 2022, the Capacity Charge recovered through Tariff C.C., approved in Case No. 2004-00420, will end. Any final over- or under-recovery balance will be included in the subsequent calculation of the purchase power adjustment under Tariff P.P.A. In the event that Kentucky Power elects not to extend the Rockport UPA, it will experience a reduction in Rockport UPA fixed costs ("Rockport Fixed Costs Savings").

(f) If Kentucky Power elects not to extend the Rockport UPA, it will, beginning December 9, 2022, credit the Rockport Fixed Cost Savings through the demand component of Tariff P.P.A. until new base rates are set. However, for 2023 only, the Rockport Fixed Cost Savings credit will be offset by the amount, if any, necessary for the Company to earn its Kentucky Commission-authorized return on equity (ROE) for 2023 ("Rockport Offset"). An example of the calculation of the Rockport Offset is included as **EXHIBIT 2**.

(g) For the purposes of implementing the Rockport Fixed Costs Savings credit described in Paragraph 3(f) above, the following definitions apply:

(i) "Rockport Fixed Costs Savings" shall mean the annual amount of non-fuel, non-environmental Rockport UPA expense included in base rates for rates effective in November 2022.

(ii) "Estimated Rockport Offset" shall mean the amount of additional annual revenue the Company estimates would be necessary for it to earn the Commission-authorized

return on equity for 2023 considering the termination of the Rockport UPA and the Rockport Fixed Cost Savings.

(iii) "Actual Rockport Offset" shall mean the amount of additional annual revenue that would have been necessary for the Company to earn the Commission-authorized return on equity for 2023 considering the termination of the Rockport UPA and the Rockport Fixed Cost Savings. The Company shall calculate the Actual Rockport Offset using a comparison of the per books return on equity for 2023 to the Commission-approved return on equity. The Actual Rockport Offset cannot exceed the Rockport Fixed Costs Savings.

(iv) "Rockport Offset True-Up" shall mean the difference between the Estimated Rockport Offset and the Actual Rockport Offset.

(h) The Company shall implement the Rockport Fixed Costs Savings credit described in Paragraph 3(f) above as follows:

(i) By November 15, 2022, the Company shall file an updated purchase power adjustment factor under Tariff P.P.A. for rates effective December 9, 2022. This filing shall reflect the impact of the Rockport Fixed Cost Savings and the Estimated Rockport Offset on the purchase power adjustment factor. This filing shall also reflect the commencement of recovery of the Rockport Deferral Regulatory Asset.

(ii) The Company shall make its normal August 15, 2023 Tariff P.P.A. filing for rates effective in October 2023. The Rockport Fixed Cost Savings and the Estimated Rockport Offset will continue to be factored into the calculation of the purchase power adjustment factor through the end of 2023. Beginning in January 2024, the Estimated Rockport Offset will not be factored into the calculation of the purchase power adjustment factor.

(iii) By February 1, 2024, the Company shall file an updated purchase power adjustment factor under Tariff P.P.A. for rates effective March 1, 2024. This filing shall only reflect the impact of the Rockport Offset True-Up on the purchase power adjustment factor. The purchase power adjustment factor shall be established to recover or credit the Rockport Offset True-Up amount in three months.

(iv) Beginning with the August 15, 2024 Tariff P.P.A. filing, the Company will incorporate the Rockport Fixed Cost Savings in its annual calculation of the purchase power adjustment factor.

4. PJM OATT LSE Expense Recovery

(a) As described in the testimony of Company Witness Vaughan, Kentucky Power has included an adjusted test year amount of net PJM OATT LSE charges and credits in base rates. Kentucky Power will track, on a monthly basis, the amount of OATT LSE charges and credits above or below the base rate level using deferral accounting. Kentucky Power will recover and collect 80% of the annual over or under collection of PJM OATT LSE charges, as compared to the annual amount included in base rates, ("Annual PJM OATT LSE Recovery") through the operation of Tariff P.P.A.

(b) Kentucky Power will credit against the Annual PJM OATT LSE Recovery 100% of the difference between the return on its incremental transmission investments calculated using the FERC-approved PJM OATT return on equity and the return on its incremental transmission investments calculated using the 9.75% return on equity provided for in this settlement (the "Transmission Return Difference"). Kentucky Power shall calculate the Transmission Return Difference as shown in **EXHIBIT 3**.

(c) These changes to Tariff P.P.A. to allow for the Annual PJM OATT LSE Recovery will terminate on the effective date when base rates are reset in the next base rate proceeding unless otherwise specifically extended by the Commission. Nothing in this Paragraph 4(c) prohibits Kentucky Power or any other Signatory Party from taking any position regarding the extension of the Annual PJM OATT LSE Recovery mechanism or any other treatment of the Company's PJM OATT LSE expenses.

5. Rate Case Stay Out

(a) Kentucky Power will not file an application for a general adjustment of base rates for rates that would be effective prior to the first day of the January 2021 billing cycle. This rate case "stay out" is expressly conditioned on Commission approval of this Settlement Agreement without modification including the recovery of the Rockport Deferral Regulatory Asset as described in Section 3 above and the incremental PJM OATT LSE expense through Tariff P.P.A. as described in Section 4 above.

(b) This stay out will not apply if a change in law occurs that will result in a material adverse effect on the Company's financial condition.

(c) Nothing in this stay out provision should be interpreted as prohibiting the Commission from altering the Company's rates upon its own investigation, or upon complaint, including to reflect changes in the tax code, including the federal corporate income tax rate, depreciation provisions, or upon a request by the Company to seek leave to address an emergency that could adversely impact Kentucky Power or its customers. In the event the Commission initiates an investigation or a complaint is filed with the Commission regarding the Company's rates, the Company retains the right to defend the reasonableness of its rates in such proceedings.

6. Tariff P.P.A.

(a) Kentucky Power's proposed changes to Tariff P.P.A., as set forth in the testimony of Company Witness Vaughan and modified by Sections 2 and 3 above, are approved.

(b) A revised version of Tariff P.P.A. incorporating the modifications described in Sections 2 and 3 above is included as **EXHIBIT 4**.

7. Depreciation Rates

(a) Kentucky Power and the Settling Intervenors agree that Big Sandy Unit 1 has an expected life of 20 years following its conversion from a coal-fired to a natural gas-fired generating unit. The depreciation rates for Big Sandy Unit 1 have been adjusted to reflect the 20 year expected life. Kentucky Power and the Signatory Parties retain the right to propose updated depreciation rates for Big Sandy Unit 1 in future proceedings to reflect updates to the expected life.

(b) Kentucky Power has adjusted depreciation rates for Big Sandy Unit 1 and for the Mitchell Plant to remove terminal net salvage costs. Kentucky Power retains the right to propose updated depreciation rates for Big Sandy Unit 1 and for the Mitchell Plant in future proceedings to include terminal net salvage costs, and the Settling Intervenors retain the right to challenge the inclusion of such costs in future proceedings.

(c) Kentucky Power's updated depreciation rates are included as **EXHIBIT 5**.

8. Return on Equity, Capitalization, WACC, and GRCF

(a) Kentucky Power shall be authorized a 9.75% return on equity. The authorized return on equity of 9.75% will be used in the calculation of the Company's Environmental Surcharge factor (for non-Rockport environmental projects) and the carrying charges for the Rockport Deferral and Decommissioning Rider regulatory assets.

(b) Kentucky Power will update its capitalization to reflect short term debt as 1% of the Company's total capital structure. The annual interest rate for the short term debt will be set at 1.25%.

(c) Kentucky Power shall utilize a weighted average cost of capital ("WACC") of 9.11% including a gross revenue conversion factor ("GRCF") of 1.6433%. The GRCF does not include a Section 199 deduction. This WACC and GRCF shall remain constant (including for the riders and surcharges described in Paragraph 8(a) above) until such time as the Commission sets base rates in the Company's next base rate case proceeding. The calculations of the WACC and GRCF are shown on **EXHIBIT 6**.

9. Storm Damage Expense Amortization

(a) Kentucky Power will recover and amortize the remaining unamortized balance of its deferred storm expense regulatory asset authorized in Case No. 2012-00445 over a period of five years beginning January 1, 2018, consistent with the recommendation of KIUC. The unamortized balance of the regulatory asset authorized in Case No. 2012-00445 will total $6,087,000 on December 31, 2017 and will be amortized over five years at an annual amount of $1,217,400.

(b) Kentucky Power will recover and amortize the deferred storm expense regulatory asset authorized in Case No. 2016-00180 over a period of 5 years beginning January 1, 2018 consistent with the testimony of Company Witness Wohnhas. The balance of the regulatory asset authorized in Case No. 2016-00180 totals $4,377,336 and will be amortized over five years at an annual amount of $875,467.

(c) The combined balance of the Kentucky Power's deferred storm expense regulatory assets (the remaining unamortized balance authorized in Case No. 2012-00445 and the amount

authorized in Case No. 2016-00180) will total \$10,464,336 on December 31, 2017 and will be amortized over five years at an annual amount of \$2,092,867.

10. Kentucky Economic Development Surcharge

(a) Kentucky Power's new Kentucky Economic Development Surcharge Tariff ("Tariff K.E.D.S.") shall be approved with rates amended as follows:

(i) The KEDS rate for residential customers will be set at \$0.10 per meter instead of \$0.25 as proposed by the Company.

(ii) The KEDS rate for non-residential customers for which the KEDS applies will be set at \$1.00 per meter instead of \$0.25 as proposed by the Company.

(b) All KEDS funds collected by Kentucky Power shall be matched dollar-for-dollar by Kentucky Power from shareholder funds. The proceeds of KEDS and Kentucky Power's shareholder contribution shall be used by Kentucky Power for economic development projects, including the training of local economic development officials, in the Company's service territory. The KEDS, and the matching shareholder contribution, shall remain in effect until changed by order of the Commission.

(c) Kentucky Power will continue to file on or before March 31st of each year a report with the Commission describing: (i) the amount collected through the Economic Development Surcharge; and (ii) the matching amount contributed by Kentucky Power from shareholder funds. The annual report to be filed by the Company shall also describe the amount, recipients, and purposes of its expenditure of the funds collected through the Economic Development Surcharge and shareholder contribution.

(d) Kentucky Power shall serve a copy of the annual report to be filed with the Commission in accordance with subparagraph (c) on counsel for all parties to this proceeding.

11. Backup and Maintenance Service

(a) In order for Marathon Petroleum LP ("Marathon") to evaluate the economics of self or co-generation, Kentucky Power and Marathon will begin negotiations regarding the terms, conditions and pricing for backup and maintenance service within 30 days of a Commission Order approving this provision and will complete negotiations within the next 120 days. Prior to the start of the 120 day negotiation period, Marathon will provide Kentucky Power with specific information regarding the MW size of a potential self or co-generation facility and the type of generation technology being considered.

(b) If Kentucky Power and Marathon cannot reach an agreement on backup and maintenance service within 120 days, Kentucky Power and Marathon agree to submit the issue to the Commission for resolution.

12. School Energy Manager Program

(a) Kentucky Power shall seek leave from the Commission to include up to $200,000 for the School Energy Manager Program in its each of its 2018 and 2019 DSM Program offerings.

(b) Kentucky Power and KSBA both expressly acknowledge that there is in Case No. 2017-00097 a currently-pending Commission investigation of the Company's DSM programs and funding and that the outcome of that investigation could impact the School Energy Manager Program.

13. Tariff K-12 School

(a) Kentucky Power shall continue its current Pilot Tariff K-12 School but shall remove the Pilot designation as set forth in **EXHIBIT 7**. Tariff K-12 School shall be available for general service to all K-12 schools in the Company's service territory, public and private, with normal maximum demands greater than 100 kW. Tariff K-12 School shall reflect rates for

customers taking service under the tariff designed to produce annually in the aggregate $500,000 less from Tariff K-12 School customers than would be produced under the new L.G.S. rates to be established under this Settlement Agreement from customers eligible to take service under Tariff K-12 School. The aggregate total revenues to be produced by Tariff K-12 School and Tariff L.G.S. shall be equal to the revenues that would be produced in the aggregate by the new rates in the absence of Tariff K-12 School. Service under Tariff K-12 School shall be optional.

14. Bill Format Changes

(a) The bill formatting changes proposed by the Company in Case No. 2017-00231 and consolidated into this case by Commission Order dated July 17, 2017, to the extent not already approved, are approved.

(b) Within 180 days of a Commission Order approving this Settlement, Kentucky Power will conduct a training session with representatives from its municipal clients and KLC to explain the new bill format and tools available to clients to evaluate their electric usage.

15. Renewable Power Option Rider

(a) The proposed changes to the Company's Green Pricing Option Rider, including renaming the rider to the Renewable Power Option Rider ("Rider R.P.O."), are approved except that the availability of service provision for Option B will state the following:

> "Customers who wish to directly purchase the electrical output and all associated environmental attributes from a renewable energy generator may contract bilaterally with the Company under Option B. Option B is available to customers taking metered service under the Company's I.G.S., and C.S.-I.R.P. tariffs, or multiple L.G.S. tariff accounts with common ownership under a single parent company that can aggregate multiple accounts to exceed 1000 kW of peak demand."

A revised version of Rider R.P.O. incorporating the modifications described above is included as EXHIBIT 8. Bills for customers receiving service under Rider R.P.O. will include a separate line item for Rider R.P.O. charges.

(b) Beginning no later than March 31, 2018, and no later than each March 31 thereafter, Kentucky Power will file a report with the Commission describing the previous year's activity under Rider R.P.O. This annual report will replace the semi-annual reports filed in Case No. 2008-00151.

16. Modifications To Kentucky Power's Rate Tariffs

In addition to the rate and tariff changes described and agreed to above, Kentucky Power and the Settling Intervenors agree that the following tariffs shall be modified or implemented as described below:

(a) The Customer charge for the Residential Class ("Tariff R.S.") shall be increased to \$14.00 per month instead of the \$17.50 per month proposed by the Company in its filing in this case.

(b) The Company is extending the termination date for Tariff C.S. – Coal and the amendments to Tariff C.S. – I.R.P. and Tariff E.D.R. approved in Case No. 2017-00099 from December 31, 2017 to December 31, 2018.

(c) The pole attachment rate under Tariff C.A.T.V. shall be \$10.82 for attachments on two-user poles and \$6.71 for attachments on three-user poles for all attachments instead of the \$11.97 for attachments on two-user poles and \$7.42 for attachments on three-user poles proposed by the Company in its filing in this case.

17. Filing Of Settlement Agreement With The Commission And Request For Approval

Following the execution of this Settlement Agreement, Kentucky Power and the Settling Intervenors shall file this Settlement Agreement with the Commission along with a joint request to the Commission for consideration and approval of this Settlement Agreement so that Kentucky

Power may begin billing under the approved adjusted rates for service rendered on or before January 19, 2018.

18. Good Faith And Best Efforts To Seek Approval

(a) This Settlement Agreement is subject to approval by the Public Service Commission.

(b) Kentucky Power and the Settling Intervenors shall act in good faith and use their best efforts to recommend to the Commission that this Settlement Agreement be approved in its entirety and without modification and that the rates and charges set forth herein be implemented.

(c) Kentucky Power and the Settling Intervenors filed testimony in this case. Kentucky Power also filed testimony in support of the Settlement Agreement. For purposes of any hearing, the Settling Intervenors and Kentucky Power waive all cross-examination of the other Signatory Parties' witnesses except for purposes of supporting this Settlement Agreement unless the Commission disapproves this Settlement Agreement. Each further stipulates and recommends that the Notice of Intent, Application, testimony, pleadings, and responses to data requests filed in this proceeding be admitted into the record.

(d) The Signatory Parties further agree to support the reasonableness of this Settlement Agreement before the Commission, and to cause their counsel to do the same, including in connection with any appeal from the Commission's adoption or enforcement of this Settlement Agreement.

(e) No party to this Settlement Agreement shall challenge any Order of the Commission approving the Settlement Agreement in its entirety and without modification.

19. Failure Of Commission To Approve Settlement Agreement

If the Commission does not accept and approve this Stipulation in its entirety, then any adversely affected Party may withdraw from the Stipulation within the statutory periods provided for rehearing and appeal of the Commission's order by (1) giving notice of withdrawal to all other Parties and (2) timely filing for rehearing or appeal. Upon the latter of (1) the expiration of the statutory periods provided for rehearing and appeal of the Commission's order and (2) the conclusion of all rehearing's and appeals, all Parties that have not withdrawn will continue to be bound by the terms of the Stipulation as modified by the Commission's order.

20. Continuing Commission Jurisdiction

This Settlement Agreement shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

21. Effect of Settlement Agreement

This Settlement Agreement shall inure to the benefit of, and be binding upon, the parties to this Settlement Agreement, their successors, and assigns.

22. Complete Agreement

This Settlement Agreement constitutes the complete agreement and understanding among the parties to this Settlement Agreement, and any and all oral statements, representations, or agreements. Any and all such oral statements, representations, or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into this Settlement Agreement.

23. Independent Analysis

The terms of this Settlement Agreement are based upon the independent analysis of the parties to this Settlement Agreement, are the product of compromise and negotiation, and reflect a fair, just, and reasonable resolution of the issues herein. Notwithstanding anything contained in this Settlement Agreement, Kentucky Power and the Settling Intervenors recognize and agree that the effects, if any, of any future events upon the income of Kentucky Power are unknown and this Settlement Agreement shall be implemented as written.

24. Settlement Agreement And Negotiations Are Not An Admission

(a) This Settlement Agreement shall not be deemed to constitute an admission by any party to this Settlement Agreement that any computation, formula, allegation, assertion, or contention made by any other party in these proceedings is true or valid. Nothing in this Settlement Agreement shall be used or construed for any purpose to imply, suggest or otherwise indicate that the results produced through the compromise reflected herein represent fully the objectives of the Signatory Parties.

(b) Neither the terms of this Settlement Agreement nor any statements made or matters raised during the settlement negotiations shall be admissible in any proceeding, or binding on any of the parties to this Settlement Agreement, or be construed against any of the parties to this Settlement Agreement, **except that** in the event of litigation or proceedings involving the approval, implementation or enforcement of this Agreement, the terms of this Settlement Agreement shall be admissible. This Settlement Agreement shall not have any precedential value in this or any other jurisdiction.

25. Consultation With Counsel

The parties to this Settlement Agreement warrant that they have informed, advised, and consulted with their respective counsel with regard to the contents and significance of this Settlement Agreement and are relying upon such advice in entering into this agreement.

26. Authority To Bind

Each of the signatories to this Settlement Agreement hereby warrant they are authorized to sign this agreement upon behalf of, and bind, their respective parties.

27. Construction Of Agreement

This Settlement Agreement is a product of negotiation among all parties to this Settlement Agreement, and no provision of this Settlement Agreement shall be construed in favor of or against any party hereto. This Settlement Agreement is submitted for purposes of this case only and is not to be deemed binding upon the parties hereto in any other proceeding, nor is it to be offered or relied upon in any other proceeding involving Kentucky Power or any other utility.

28. Counterparts

This Settlement Agreement may be executed in multiple counterparts.

29. Future Rate Proceedings

Nothing in this Settlement Agreement shall preclude, prevent, or prejudice any party to this Settlement Agreement from raising any argument or issue, or challenging any adjustment, in any future rate proceeding of Kentucky Power.

IN WITNESS WHEREOF, this Settlement Agreement has been agreed to as of this 22nd day of November 2017.

KENTUCKY POWER COMPANY

By: ______________________

Its: Counsel

KENTUCKY INDUSTRIAL UTILITY
CUSTOMERS, INC.

By: Michael Kurtz

Its: Counsel

KENTUCKY SCHOOL BOARDS
ASSOCIATION, INC.

By: Matthew Malone

Its: Legal Counsel

KENTUCKY LEAGUE OF CITIES

By: [signature]

Its: Director of Municipal Law & Training

KENTUCKY CABLE
TELECOMMUNICATION
ASSOCIATION, INC.

By: ____________________

Its: KCTA Board Chairman

WAL-MART STORES EAST, LP AND
SAM'S EAST, INC.

By: ______________________

Its: Counsel

CASE NO. 2017-00179
SETTLEMENT AGREEMENT
EXHIBIT LIST

1. Revenue Allocation
2. Rockport Offset Calculation
3. Transmission Return Difference Calculation
4. Revised Tariff P.P.A.
5. Depreciation Rates
6. Calculation of WACC and GRCF
7. Revised Tariff K-12 School
8. Revised R.P.O. Rider

EXHIBIT 1

Kentucky Power Company
Settlement Agreement Exhibit-1
Case No. 2017-00179
Settlement Revenue Allocation

Customer Class	Base Rate Case Settlement Increase						Increase Incorporating Surcharge Changes			Return on Rate Base		Settlement
	Settlement Base Rate Increase	ECP	HEAP KEDS	Total Increase	Test Year Rev	% Increase	Carrying Charge Savings in ES	Net Increase	Total Bill % Increase	Current ROR	Proposed ROR	Proposed Non-Fuel Base Revenue Increase
	a	b	c	d = a+b+c	e	= d/e	f	g = d+f	= g/e			
RS	$ 20,076,436	$1,734,600	594	21,811,630	$232,952,481	9.36%	($835,019)	$20,976,611	9.00%	1.90%	3.77%	14.15%
SGS	$ 984,981	$184,183	247,506	1,416,670	$21,371,729	6.63%	($88,664)	$1,328,006	6.21%	11.30%	12.90%	7.19%
MGS	$ 3,421,623	$500,403	69,324	3,991,350	$60,245,787	6.63%	($240,889)	$3,750,461	6.23%	9.14%	10.96%	9.24%
GS*	$ 4,406,604	$ 684,586	$ 316,830	$ 5,408,020	$ 81,617,516	6.63%	($329,553)	$5,078,467	6.22%	9.67%	11.43%	8.68%
LGS/PS	$ 3,520,149	$549,861	8,467	4,078,477	$70,567,216	5.78%	($264,698)	$3,813,779	5.40%	8.78%	10.45%	8.61%
IGS	$ 3,534,466	$836,950	694	4,372,110	$157,911,866	2.77%	($402,899)	$3,969,211	2.51%	6.82%	7.71%	5.85%
MW	$ 4,956	$1,620	102	6,678	$221,405	3.02%	($780)	$5,898	2.66%	12.12%	13.02%	3.94%
OL	$ 201,254	$82,080	0	283,334	$8,984,564	3.15%	($39,512)	$243,822	2.71%	15.03%	15.68%	2.87%
SL	$ 36,869	$13,751	0	50,620	$1,645,931	3.08%	($6,620)	$44,000	2.67%	15.92%	16.84%	3.29%
Total	$ 31,780,734	$ 3,903,448	$ 326,687	$ 36,010,869	$ 553,900,979	6.50%	($1,879,080)	$34,131,789	6.16%	4.85%	5.48%	9.47%

* GS is the combination of the SGS and MGS classes

EXHIBIT 2

Kentucky Power Company
Exhibit 2 - Rockport Offset Calculation Example
Case No. 2017-00179

	*Calculation**			Source
a	12 Month GAAP Net Income	$	97,000,000	Q4 2023 Per Books as Reported SEC Kentucky Power Company
b	13 Month Average Common Equity	$	1,000,000,000	Q4 2023 Per Books as Reported SEC Kentucky Power Company
c = a/b	Return on Common Equity		9.70%	Calculation
d	Kentucky Power Allowed Retail ROE		9.75% **	Commission Order
	If D < C, Stop If D > C, Continue to Part e			
e = (b*d)-a	Net GAAP Income Increase Required to Earn Allowed Retail ROE	$	500,000	Calculation
f	Gross Revenue Conversion Factor		1.6433 **	Commission Order
g = e*f	Rockport Earnings Retainer Revenue	$	821,670	Calculation
= g	*Amount to Be Recovered Through Tariff PPA*	*$*	*821,670*	

*These numbers are illustrative
** Or as updated in a future Commission proceeding

EXHIBIT 3

Kentucky Power Company
Settlement Exhibit 3 - Transmission Return Difference Calculation
Case No. 2017-00179

	*Calculation**			*Source*	*Frequency*
a	TO Transmission Rate Base	$	319,471,085	2018 OATT TCOS	Update Annually
b	KY Juris Retail Demand Factor		0.985	2017-00179 Section V, Allocation Factors	Remains Static
c = a*b	KY Retail TO Trans Rate Base	$	314,679,018	calculation	
d	Base Rate KY Retail Trans Rate Base	$	266,193,980	2017-00179 Class Cost of Service	Remains Static
e = c-d	Difference	$	48,485,038	calculation	
f	TO WACC @ 11.49 ROE		7.55%	2018 OATT TCOS	Update Annually
g	TO WACC @ 9.75 ROE		6.78%	2018 OATT TCOS	Update Annually
h = f-g	Difference		0.77%	calculation	
j = e*h	TO Return Delta	$	371,431	calculation	
k	GRCF		1.6351	2018 OATT TCOS	Update Annually
= j*k	*2018 Tariff PPA Revenue Credit*	*$*	*607,326*	calculation	Update Annually

*These numbers are illustrative

EXHIBIT 4

KENTUCKY POWER COMPANY P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 35-1
CANCELLING P.S.C. KY. NO. 11 ________ SHEET NO. 35-1

TARIFF P.P.A.
(Purchase Power Adjustment)

APPLICABLE.

To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., K-12 School, L.G.S., L.G.S.-T.O.D., I.G.S., C.S. – I.R.P., M.W., O.L. and S.L.

RATE.

The annual purchase power adjustment factor will be computed using the following formula:

1. Annual Purchase Power Net Costs (PPANC)

   PPANC = N+RP+CSIRP+G+OATT+RKP-BPP

   Where:
   BPP = The annual amount of purchase power costs included in base rates, $78,737,938.

   a. N = The annual cost of power purchased by the Company through new Purchase Power Agreements. All new purchase power agreements shall be approved by the Commission to the extent required by KRS 278.300.
   b. RP = The annual purchased power costs not otherwise recoverable in the Fuel Adjustment Clause including but not limited to the cost of fuel related substitute generation less the cost of fuel which would have been used in plants suffering forced generation or transmission outages and the cost of purchases in excess of the highest cost owned or leased unit.
   c. CSIRP = The net annual cost of any credits provided to customers under Tariff C.S.-I.R.P. for interruptible service.
   d. G = The annual gains and losses on incidental gas sales; and
   e. OATT = 80% The net annual PJM load-serving entity Open Access Transmission Tariff Charges above or below the $74,038,517 included in BPP, less the transmission return difference pursuant to the Commission approved Settlement agreement in Case No. 2017-00179.
   f. RKP = Rockport related items includable in Tariff PPA pursuant to the Commission approved Settlement agreement in Case No. 2017-00179:
      i. Increase in Rockport collection resulting from reduction in base rate deferral;
      ii. Rockport deferral amount to be recovered;
      iii. Rockport fixed cost savings; and T
      iv. Rockport offset estimate and true-up.
      v. Final (over)/under recovery associated with tariff CC following its expiration

(Cont'd on Sheet No. 35-2)

DATE OF ISSUE:

DATE EFFECTIVE: Service Rendered On And After January 19, 2018

ISSUED BY: Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated XXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 35-2
CANCELLING P.S.C. KY. NO. 11 _________ SHEET NO. 35-2

N

TARIFF P.P.A. (Cont'd)
(Purchase Power Adjustment)

RATES.

Tariff Class	\$/kWh	\$/kW
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.	\$0.00000	--
S.G.S.-T.O.D.	\$0.00000	--
M.G.S.-T.O.D.	\$0.00000	--
G.S.	\$0.00000	--
L.G.S., P.S, L.G.S.-T.O.D.	\$0.00000	\$0.00
L.G.S.-L.M.-T.O.D.	\$0.00000	--
I.G.S. and C.S.-I.R.P.	\$0.00000	\$0.00
M.W.	\$0.00000	--
O.L.	\$0.00000	--
S.L.	\$0.00000	--

The kWh factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW factor as calculated above will be applied to all on-peak and minimum billing demand kW for the LGS and IGS tariff classes.

The Purchase Power Adjustment factors shall be modified annually using the following formula:

The Purchase Power Adjustment factors shall be determined as follows:
For all tariff classes without demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total}) + PPA(D) \times (CP_{Class} / CP_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = 0$$

For all tariff classes with demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = \frac{PPA(D) \times (CP_{Class} / CP_{Total})}{BD_{Class}}$$

N

(Cont'd on Sheet No. 35-3)

DATE OF ISSUE:

DATE EFFECTIVE: Service Rendered On And After January 19, 2018

ISSUED BY: Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

In Case No. 2017-00179 Dated XXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 35-3
CANCELLING P.S.C. KY. NO. 11 ________ SHEET NO. 35-3

N

TARIFF P.P.A. (Cont'd)
(Purchase Power Adjustment)

RATES. (Cont'd)

Where:

1. "PPA(D)" is the actual annual retail PPA demand-related costs, plus any prior review period (over)/under recovery.
2. "PPA(E) is the actual annual retail PPA energy-related costs, plus any prior review period (over)/under recovery.
3. "BE_{Class}" is the historic annual retail jurisdictional billing kWh for each tariff class for the current year.
4. "BD_{Class}" is the historic annual retail jurisdictional billing kW for each applicable tariff class for the current year.
5. "CP_{Class}" is the coincident peak demand for each tariff class estimated as follows:

Tariff Class	BE_{Class}	CP/kWh Ratio	CP_{Class}
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.		0.0240909%	
S.G.S.-T.O.D.		0.0196553%	
M.G.S.-T.O.D.		0.0196553%	
G.S.		0.0196553%	
L.G.S., P.S, L.G.S.-T.O.D		0.0170480%	
L.G.S.-L.M.-T.O.D.		0.0170480%	
I.G.S. and C.S.-I.R.P.		0.0118222%	
M.W.		0.0135480%	
O.L.		0.0000000%	
S.L.		0.0000000%	

6. "BE_{Total}" is the sum of the BE_{Class} for all tariff classes.
7. "CP_{Total}" is the sum of the CP_{Class} for all tariff classes.
8. The factors as computed above are calculated to allow the recovery of Uncollectible Accounts Expense of 0.34% and the KPSC Maintenance Fee of 0.1996% and other similar revenue based taxes or assessments occasioned by the Purchase Power Adjustment revenues.
9. The annual PPA factors shall be filed with the Commission by August 15 of each year with the exception of the Rockport items includable in Tariff PPA pursuant to the Commission approved Settlement agreement in Case No. 2017-00179, with rates to begin with the October billing period, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

   Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884. N

DATE OF ISSUE:

DATE EFFECTIVE: Service Rendered On And After January 19. 2018

ISSUED BY: Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated XXXXXXX

EXHIBIT 5

Exhibit 5 - Depreciation Rates
Case No. 2017-00179

KENTUCKY POWER COMPANY
BIG SANDY UNIT 1 AND MITCHELL PLANT SETTLEMENT DEPRECIATION RATES CALCULATION
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2013 (MITCHELL) AND AT DECEMBER 31, 2016 (BIG SANDY UNIT 1)
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

									Annual Accrual	
Acct.	Title	Original Cost	Net Salvg. Ratio	Total to be Recovered	Calculated Depreciation Requirement	Accumulated Depreciation	Remaining to Be Recovered	Avg. Remain Life	Amount	Percent
(I)	(II)	(III)	(IV)	(V)	(VI)	(VII)	(VIII)	(IX)	(X)	(XI)
STEAM PRODUCTION PLANT										
Big Sandy Unit 1										
311.0	Structures & Improvements	11,756,127	1.02	11,991,250	7,526,502	4,805,397	7,185,853	20.00	359,293	3.06%
312.0	Boiler Plant Equipment	75,388,722	1.02	76,896,496	22,552,265	9,774,280	67,122,216	20.00	3,356,111	4.45%
314.0	Turbogenerator Units	61,392,346	1.02	62,620,193	36,338,075	28,424,981	34,195,212	20.00	1,709,761	2.78%
315.0	Accessory Electrical Equip.	3,877,136	1.02	3,954,679	2,964,549	2,578,951	1,375,728	20.00	68,786	1.77%
316.0	Misc. Power Plant Equip.	3,321,344	1.02	3,387,771	2,153,127	1,512,867	1,874,904	20.00	93,745	2.82%
	Total	155,735,675		158,850,389	71,534,518	47,096,476	111,753,913		5,587,696	3.59%
Mitchell Plant										
311	Structures & Improvements	42,000,197	1.03	43,260,203	18,282,178	16,183,402	27,076,801	25.01	1,082,639	2.58%
312	Boiler Plant Equipment	765,644,984	1.03	788,614,334	245,324,500	238,518,432	550,095,902	24.25	22,684,367	2.96%
312	Boiler Plant Equip SCR Catalyst	8,190,115	1.00	8,190,115	4,023,394	2,378,493	5,811,622	4.07	1,023,764	12.50%
314	Turbogenerator Units	53,295,697	1.03	54,894,568	29,106,660	33,613,523	21,281,045	23.84	892,661	1.67%
315	Accessory Electrical Equip.	17,080,672	1.03	17,593,092	9,466,086	11,043,285	6,549,807	25.81	253,770	1.49%
316	Misc. Power Plant Equip.	7,693,412	1.03	7,924,214	3,289,590	3,072,520	4,851,694	23.96	202,491	2.63%
	Total	893,905,077	1.03	920,476,526	309,492,408	304,809,655	615,666,871	23.55	26,139,693	2.92%

Notes:
1.) Terminal net salvage removed as a component of net salvage ratio for both plants (column IV).
2.) Average remaining life adjusted to reflect a 20 year useful life of BS1 (column IX).
3.) Mitchell Plant information from schedule used to calculate depreciation rates in settlement of Case No. 2014-00396.

EXHIBIT 6

Kentucky Power Company
Exhibit 6a - Calculation of Weighted Average Cost of Capital
Case No. 2017-00179

KENTUCKY POWER COMPANY
COST OF CAPITAL
TEST YEAR ENDED FEBRUARY 28, 2017

Line No.	Description	Reapportioned Kentucky Jurisdictional Capital 1/	Percentage of Total	Annual Cost Percentage Rate		Weighted Average Cost Percent	Gross Up	Pre-Tax Weighted Average Cost Percent
(1)	(2)	(3)	(4)	(5)		(6) = (4) X (5)	(7)	(8) = (6) X (7)
1	Long Term Debt	$636,995,903	53.45%	4.36%	2/	2.33%	1.00540	2.34%
2	Short Term Debt	11,917,855	1.00%	1.25%	3/	0.01%	1.00540	0.01%
3	Accounts Receivable F	46,105,009	3.87%	1.95%	5/	0.08%	1.00540	0.08%
4	Common Equity	496,766,726	41.68%	9.75%	6/	4.06%	1.64334	6.67%
5	Total	$1,191,785,493	100.00%			6.48%		9.11%

Kentucky Power Company
Exhibit 6b - Calculation of Gross Revenue Conversion Factor
Case No. 2017-00179

KENTUCKY POWER COMPANY
COMPUTATION OF THE GROSS REVENUE
CONVERSION FACTOR
TEST YEAR ENDED FEBRUARY 28,2017

Line No. (1)	Description (2)		Percent of Incremental Gross Revenues (3)
1	Operating Revenues		100.00%
2	Less: Uncollectible Accounts Expense 1/		0.3400%
3	KPSC Maintenance Fee		0.1996%
4	Income Before income Taxes		99.4604%
5	Less: State Income Taxes (L4 X 5.8742%) 2/	5.87%	5.843%
6	Income Before Federal Income Taxes		93.6179%
7	Less: Federal income Taxes (L6 X 35.00%)	35.00%	32.7663%
8	Operating Income Percentage		60.8516%
9	Gross Revenue Conversion Factor (100% / L8)		**1.6433**

EXHIBIT 7

KENTUCKY POWER COMPANY P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 9-9
CANCELLING P.S.C. KY. NO. 11 ________ SHEET NO. 9-9

TARIFF K-12 SCHOOL
(Public and Private School)

AVAILABILITY OF SERVICE.

Available for general service to K-12 School customers subject to KRS 160.325 with normal maximum demands greater than 100 KW but not more than 1,000 KW.

RATE.

	Service Voltage			
	Secondary	Primary	Subtransmission	Transmission
Tariff Code	260	264	268	270
Service Charge per Month	$ 85.00	$ 127.50	$ 660.00	$ 660.00
Demand Charge per KW	$ 7.97	$ 7.18	$ 5.74	$ 5.60
Excess Reactive Charge per KVA	$ 3.46	$ 3.46	$ 3.46	$ 3.46
Energy Charge per KWH	7.671¢	6.709¢	5.535¢	5.429¢

MINIMUM CHARGE.

Bills computed under the above rate are subject to a monthly minimum charge comprised of the sum of the service charge and the minimum demand charge. The minimum demand charge is the product of the demand charge per KW and the monthly billing demand.

ADJUSTMENT CLAUSES.

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 5
System Sales Clause	Sheet No. 19
Franchise Tariff	Sheet No. 20
Demand-Side Management Adjustment Clause	Sheet No. 22
Kentucky Economic Development Surcharge	Sheet No. 24
Capacity Charge	Sheet No. 28
Environmental Surcharge	Sheet No. 29
School Tax	Sheet No. 33
Purchase Power Adjustment	Sheet No. 35
Decommissioning Rider	Sheet No. 38

(Cont'd on Sheet No. 9-10)

DATE OF ISSUE:

DATE EFFECTIVE: Service Rendered On And After January 19, 2018

ISSUED BY: Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated XXXXXXX

TARIFF K-12 SCHOOL (Cont'd)
(Public and Private School)

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

(1) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.

(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

MONTHLY BILLING DEMAND.

Billing demand in KW shall be taken each month as the highest 15-minute integrated peak in kilowatts as registered during the month by a 15-minute integrating demand meter or indicator, or at the Company's option as the highest registration of a thermal type demand meter or indicator. The monthly billing demand so established shall in no event be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

DETERMINATION OF EXCESS KILOVOLT-AMPERE (KVA) DEMAND.

The maximum KVA demand shall be determined by the use of a multiplier equal to the reciprocal of the average power factor recorded during the billing month, leading or lagging, applied to the metered demand. The excess KVA demand, if any, shall be the amount by which the maximum KVA demand established during the billing period exceeds 115% of the kilowatts of metered demand.

(Cont'd on Sheet No. 9-11)

KENTUCKY POWER COMPANY P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 9-11
CANCELLING P.S.C. KY. NO. 11 ________ SHEET NO. 9-11

TARIFF K-12 SCHOOL (Cont'd)
(Public and Private School)

TERM OF CONTRACT.

Contracts under this tariff will be made for customers requiring a normal maximum monthly demand between 500 KW and 1,000 KW and be made for an initial period of not less than 1 (one) year and shall remain in effect thereafter until either party shall give at least 6 months written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts or periods greater than 1 (one) year. For customers with demands less than 500 KW, a contract may, at the Company's option, be required.

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods greater than one year for all customers served under this tariff.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

CONTRACT CAPACITY.

The Customer shall set forth the amount of capacity contracted for (the "contract capacity") in an amount up to 1,000 KW. Contracts will be made in multiples of 25 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to Customers having other sources of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the customer shall contract for the maximum amount of demand in KW, which the Company might be required to furnish, but not less than 100 KW nor more than 1,000 KW. The Company shall not be obligated to supply demands in excess of the contract capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billings periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or II or by special agreement with the Company.

DATE OF ISSUE:

DATE EFFECTIVE: Service Rendered On And After January 19, 2018

ISSUED BY: Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated XXXXXXX

EXHIBIT 8

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 31-1**
CANCELLING P.S.C. KY. NO. 11 ________ SHEET NO. 31-1

RIDER R.P.O.
(Renewable Power Option Rider)

AVAILABILITY OF SERVICE.

Available to customers taking metered service under the Company's R.S., R.S.D. , R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., K-12 School, L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P. and M.W. tariffs. T T

Participation in this program under Option A may be limited by the ability of the Company to procure renewable energy certificates (RECs) from Renewable Resources. If the total of all kWh under contract under this Rider equals or exceeds the Company's ability to procure RECs, the Company may suspend the availability of this Rider to new participants. T

Customers who wish to directly purchase the electrical output and all associated environmental attributes from a renewable energy generator may contract bilaterally with the Company under Option B. Option B is available to customers taking metered service under the Company's I.G.S., and C.S.-I.R.P. tariffs, or multiple L.G.S. tariff accounts with common ownership under a single parent company that can aggregate multiple accounts to exceed 1000 kW of peak demand. N N

CONDITIONS OF SERVICE.

Customers who wish to support the development of electricity generated by Renewable Resources may under Option A contract to purchase each month a specific number of fixed kWh blocks, or choose to cover all of their monthly usage. T T

Renewable Resources shall be defined as Wind, Solar Photovoltaic, Biomass Co-Firing of Agricultural crops and all energy crops, Hydro (as certified by the Low Impact Hydro Institute), Incremental Improvements in Large Scale Hydro, Coal Mine Methane, Landfill Gas, Biogas Digesters, Biomass Co-Firing of All Woody Waste including mill residue, but excluding painted or treated lumber. All REC's purchased under Option A of this tariff shall be retained or retired by the Company on behalf of customers. T T T

RATES.

Option A: N

In addition to the monthly charges determined according to the Company's tariff under which the customer takes metered service, the customer shall also pay the following rate for the REC option of their choosing. The charge will be applied to the customer's bill as a separate line item. T

The Company will provide customers at least 30-days' advance notice of any change in the Rate. At such time, the customer may modify or cancel their automatic monthly purchase agreement. Any cancellation will be effective at the end of the current billing period when notice is provided.

A1. Solar RECs:

Block Purchase:	Charge ($ per 100 kWh block): $ 1.00/month	N
All Usage Purchase:	Charge: $0.010/kWh consumed	N

(Cont'd on Sheet 31-2)

DATE OF ISSUE:

DATE EFFECTIVE: Service Rendered On And After January 19, 2018

ISSUED BY: Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated XXXXXXX

RIDER R.P.O. T
(Renewable Power Option Rider) T

RATES. (Cont'd)

N

A2. Wind RECs:

Block Purchase:	Charge ($ per 100 kWh block): $ 1.00/month
All Usage Purchase:	Charge: $0.010/kWh consumed

A3. Hydro & Other RECs:

Block Purchase:	Charge ($ per 100 kWh block): $ 0.30/month
All Usage Purchase:	Charge: $0.003/kWh consumed

Option B:

Charges for service under option B of this Tariff will be set forth in the written agreement between the Company and the Customer and will reflect a combination of the firm service rates otherwise available to the Customer and the cost of the renewable energy resource being directly contracted for by the Customer. N

TERM.

This is a voluntary program.

Under Option A Customers may participate through a one-time purchase, or establish an automatic monthly purchase agreement. Any payments under this program are nonrefundable. Customers participating under Option A may terminate service under this Rider by notifying the Company with at least thirty (30) days prior notice. T T T

Under Option B, the term of the agreement will be determined in the written agreement between the Company and the Customer. T

SPECIAL TERMS AND CONDITIONS.

This Rider is subject to the Company's Terms and Conditions of Service and all provisions of the tariff under which the customer takes service, including all payment provisions. The Company may deny or terminate service under this Rider to customers who are delinquent in payment to the Company.

Funds collected under this Renewable Power Option Rider will be used solely to purchase RECs for the program. T

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 31-3
CANCELLING P.S.C. KY. NO. 11 ________ SHEET NO. 31-3

DATE OF ISSUE:

DATE EFFECTIVE: Service Rendered On And After January 19, 2018

ISSUED BY: Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated XXXXXXX

STITES & HARBISON PLLC
ATTORNEYS

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Katie M. Glass
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November 15, 2022

ELECTRONICALLY FILED

Linda C. Bridwell
Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RE: **Case No. 2020-00174** (Post-Case Correspondence File)

Dear Ms. Bridwell:

Kentucky Power Company files herewith its November 15, 2022 PPA Update and clean and relined versions of its 3rd Revised Sheet No. 35-2.[1] The 3rd Revised Sheet No. 35-2 reflects modifications to the rates contained in the Company's Tariff Purchase Power Adjustment (P.P.A.). This filing is being made in order to comply with the Commission's January 18, 2018 Order in Case No. 2017-00179.[2] In that case, the Company committed in the non-unanimous settlement agreement attached to and approved by the January 18, 2018 Order ("Settlement Agreement"):

> By November 15, 2022, the Company shall file an updated purchase power adjustment factor under Tariff P.P.A. for rates effective December 9, 2022. This filing shall reflect the impact of the Rockport Fixed Cost Savings and the Estimated Rockport Offset on the purchase power adjustment factor. This filing shall also reflect the commencement of recovery of the Rockport Deferral Regulatory Asset.[3]

The Company is conscious of the pending proceeding to determine the amortization period and deferral mechanism for the Rockport Deferral Regulatory Asset, and the credit for the

---

[1] 3rd Revised Sheet No. 35-2 also is being filed with the Commission through its Electronic Tariff Filing System.

[2] Order, *In The Matter Of: Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief*, Case No. 2017-00179 (Ky. P.S.C. January 18, 2018).

[3] *Id.* at PDF page 86 of 122.

STITES & HARBISON PLLC
ATTORNEYS

Rockport Fixed Costs Savings and Rockport Offset (Case No. 2022-00283),[4] and the effect that proceeding may have on Tariff P.P.A. and the proposed revisions included with this filing. The Company nonetheless is making this filing in order to ensure it is compliant with any requirements in the Commission's January 18, 2018 Order in Case No. 2017-00179 to make such a filing.

Please do not hesitate to contact me if you have any questions.

Very truly yours,

STITES & HARBISON PLLC

Katie M. Glass

KMG

[4] *In The Matter Of: Electronic Investigation Of Kentucky Power Company Rockport Deferral Mechanism*, Case No. 2022-00283.

Summary of Changes to Form 1.0
From August 2022 Filing

Line		As Filed August 2022	Adjustment	Beginning December 9, 2022 (Annualized Basis)
(1)	Actual Non-Rockport PPA Costs 12-Months Ended June 30, 2022 - Form 3.0	116,724,305		116,724,305
(2)	Non-Rockport PPA Base Rate Amount - Form 5.0 (Based on No. of Months)	98,165,700		98,165,700
(3)	Non-Rockport Current Period Revenue Requirement - Form 3.0	18,558,604		18,558,604
(4)	Increase in Rockport Collection - Reduction of Amount of Rockport Base Rate Deferral (2020 - Dec 8, 2022)*	10,000,000	(10,000,000)	-
(5)	Rockport Fixed Cost Savings (Dec 9, 2022+)	-	(40,831,141)	(40,831,141)
(6)	Subtotal (Line 3 + Line 4 + Line 5)	28,558,604		(22,272,537)
(7)	Gross-Up (Line 6 X .006093)	174,008		(135,707)
(8)	Rockport Deferral Amount to be Recovered through the PPA (Dec 9, 2022 - Dec 8, 2027)	-	13,539,510	13,539,510
(9)	Estimated Rockport Offset Amount (2023)	-	22,785,645	22,785,645
(10)	Rockport Offset True-Up (2024)	-		-
(11)	PPA Revenue Requirement before Prior Period Over/Under (Line 6 + Line 7 + Line 8 + Line 9 + Line 10)	28,732,612		13,916,912
(12)	Actual PPA Revenue Collected For 12-Months Ended June 30, 2022 from PPA Form 4.0	20,956,127		20,956,127
(13)	Prior Period PPA Revenue Target - Previous PPA Update Filing	20,937,074		20,937,074
(14)	Calculated Going Level PPA Revenue Requirement (Line 11 - Line 12 + Line 13)	28,713,559		13,897,858

PPA - Form 1.0

Kentucky Power Company
Purchase Power Adjustment
Based on 12 -Month Period ended June 30, 2022
With Impact of the Rockport Fixed Cost Savings and the Estimated Rockport Offset As Approved in 2017 Settlement Agreement**

Line			
(1)	Actual Non-Rockport PPA Costs 12-Months Ended June 30, 2022 - Form 3.0	116,724,305	
(2)	Non-Rockport PPA Base Rate Amount - Form 5.0 (Based on No. of Months)	98,165,700	
(3)	Non-Rockport Current Period Revenue Requirement - Form 3.0	18,558,604	
(4)	Increase in Rockport Collection - Reduction of Amount of Rockport Base Rate Deferral (2020 - Dec 8, 2022)*	-	
(5)	Rockport Fixed Cost Savings (Dec 9, 2022+)	(40,831,141)	
(6)	Subtotal (Line 3 + Line 4 + Line 5)	(22,272,537)	
(7)	Gross-Up (Line 6 X .006093)	(135,707)	
(8)	Rockport Deferral Amount to be Recovered through the PPA (Dec 9, 2022 - Dec 8, 2027)	13,539,510	
(9)	Estimated Rockport Offset Amount (2023)	22,785,645	
(10)	Rockport Offset True-Up (2024)	-	NA This Filing
(11)	PPA Revenue Requirement before Prior Period Over/Under (Line 6 + Line 7 + Line 8 + Line 9 + Line 10)	13,916,912	
(12)	Actual PPA Revenue Collected For 12-Months Ended June 30, 2022 from PPA Form 4.0	20,956,127	
(13)	Prior Period PPA Revenue Target - Previous PPA Update Filing	20,937,074	
(14)	Calculated Going Level PPA Revenue Requirement (Line 11 - Line 12 + Line 13)	13,897,858	

a.) Demand	$13,149,840
b.) Energy	$748,018
	$13,897,858

* $5 million in 2020, $10 million in 2021 and 2022

Kentucky Power Company
Purchase Power Adjustment Rate Design

PPA - Form 2.0

	Demand	Energy	Total
KY Retail Jurisdiction			
Revenue Requirement	$13,149,840	$748,018	$13,897,858

Class	Historic Period Billing Energy	Historic Period Billing Demand	Test Year CP / kWh Ratio	CP Demand Allocation Factor	Allocated Demand Related Costs	Allocated Energy Related Costs	$ / kW Rate	$ / kWh Rate	Revenue Verification	Difference
(1)	(2)	(3)	(4)	(5) = (2) x (4)	(6) on (5)	(7) on (2)	(8) = (6) / (3)	(9) = (7) / (2)	(10)	(11) = (10) - (6) - (7)
RES	1,950,552,428		0.0242800%	473,594	$6,602,062	$280,284	$ -	$0.00353	$6,885,450	$3,104
GS (SGS/MGS)	621,062,180		0.0196200%	121,852	1,698,658	89,243	$ -	$0.00288	1,788,659	$758
LGS	493,155,443	1,502,999	0.0179800%	88,669	1,236,076	70,864	$ 0.82	$0.00014	1,301,501	-$5,439
LGS LMTOD	1,818,646		0.0179800%	327	4,558	261	$ -	$0.00265	4,819	$0
IGS	2,088,777,292	3,458,695	0.0123200%	257,337	3,587,366	300,146	$ 1.04	$0.00014	3,889,471	$1,959
MW	1,830,736		0.0132600%	243	3,388	263	$ -	$0.00199	3,643	-$8
OL	39,967,390		0.0026300%	1,051	14,651	5,743	$ -	$0.00051	20,383	-$11
SL	8,444,372		0.0026200%	221	3,081	1,213	$ -	$0.00051	4,307	$13
Total	5,205,608,487	4,961,694		943,294	$13,149,840	$748,017			$13,898,234	$377

PPA - Form 3.0

Kentucky Power Company
PPA Costs
Actual Operating Expenses for the 12 Month period ended June 30, 2022

Account	Description		Actual Period Total	Classification	Allocation		Retail Total
4561005	PJM Point to Point Trans Svc	$	(1,518,258)	Demand	1.00	$	(1,518,258)
4561002	RTO Formation Cost Recovery	$	-	Demand	1.00	$	-
4561035-LSE	PJM Affiliated Trans NITS Cost	$	48,318,964	Demand	1.00	$	48,318,964
4561036-LSE	PJM Affiliated Trans TO Cost	$	(250,730)	Energy	1.00	$	(250,730)
4561060-LSE	Affil PJM Trans Enhancmnt Cost	$	1,165,747	Demand	1.00	$	1,165,747
5650012	PJM Trans Enhancement Charge	$	1,835,083	Demand	1.00	$	1,835,083
5650016	PJM NITS Expense - Affiliated	$	55,148,870	Demand	1.00	$	55,148,870
5650019	Affil PJM Trans Enhncement Exp	$	5,255,347	Demand	1.00	$	5,255,347
5650021	PJM NITS Expense - Non-Affiliated	$	543,999	Demand	1.00	$	543,999
5650015	PJM TO Serv Expense - Affiliated	$	208,398	Energy	1.00	$	208,398
PJM LSE OATT						**$**	**110,707,418**
PJM LSE OATT Base Amount						**$**	**96,896,496**
Incremental PJM LSE OATT						$	13,810,922
Incremental PJM LSE OATT*						**$**	**13,810,922**
PJM LSE OATT To be included in PPA						**$**	**13,810,922**
Actual Forced Outage Related Purchase Power and CS IRP Credits Paid		$	6,324,732	Energy	Allocated Monthly	$	6,324,732
Forced Outage Related Purchase Power and CS IRP Credits in Base Rates		$	1,269,204			$	1,269,204
FERC vs KY Retail ROE Delta Return Calculation			($307,846)	Demand	1	$	(307,846)
Total PPA Costs						**$**	**18,558,604**

		$	%		
Total Demand	$	110,441,905	94.62%	$	110,441,905
Total Energy	$	6,282,400	5.38%	$	6,282,400
				$	116,724,305

Notes

* Previously 80% incremental recovery; now 100% incremental recovery as issued by the Public Service Commission in Order dated January 13, 2021 in Case No. 2020-00174

KPCo
PPA Rider Over Under Recovery
12 -Month Period ended June 30, 2022

			2021						2022						
			Per Books	Per Books	Per Books	Per Books	Per Books	Per Books	Per Books	Per Books	Per Books	Per Books	Per Books	Per Books	Review Period Total
		KPCo	**July**	**August**	**September**	**October**	**November**	**December**	**January**	**February**	**March**	**April**	**May**	**June**	
Revenue:		Billed & Accrued Revenue	1,166,924	1,472,358	746,152	1,573,420	1,948,275	2,360,771	2,403,181	2,031,556	1,883,397	1,683,270	2,382,014	1,304,809	20,956,127
		Adjustments	(7,067)	(8,916)	(4,519)	(9,528)	(11,799)	(14,297)	(14,553)	(12,303)	(11,406)	(10,194)	(14,425)	(7,902)	(126,908)
			1,159,857	1,463,442	741,633	1,563,892	1,936,477	2,346,474	2,388,628	2,019,254	1,871,991	1,673,076	2,367,589	1,296,907	20,829,220
Base Rates:		**Monthly Approved PPA Base Amount included in Base Rates**	8,074,708	8,074,708	8,074,708	8,074,708	8,074,708	8,074,708	8,074,708	8,074,708	8,074,708	8,074,708	8,074,708	8,074,708	96,896,496
Expense:	**Account No.**	**Account Description**													
	5650021	PJM NITS Expense - Non-Affiliated	41,859	42,017	42,017	41,859	42,017	41,859	43,445	43,343	42,877	52,467	47,722	62,517	543,999
	5650015	PJM TO Serv Expense - Affiliated	26,607	27,041	22,984	20,734	24,853	26,698	12,619	10,148	9,645	8,400	8,926	9,744	208,398
	4561005	Firm and Non-Firm Point to Point Transmision Revenues	(110,045)	(149,584)	(82,004)	(21,449)	(109,952)	(143,453)	(180,837)	(174,887)	(144,824)	(111,775)	(142,779)	(146,669)	(1,518,258)
	4561002	RTO Formation Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
	5550155	Purchase Power VCS Credit	-	-	-	-	-	-	-	-	-	-	-	-	-
	4561035	Network Integrated Transmission Service	3,936,103	3,936,103	3,808,359	3,936,103	3,808,359	3,936,103	4,280,809	3,864,298	4,280,809	4,119,297	4,276,274	4,136,349	48,318,964
	4561036	Schedule 1a Charges	(15,468)	(15,720)	(13,362)	(12,054)	(14,448)	(15,521)	(34,825)	(28,008)	(26,619)	(23,181)	(24,633)	(26,892)	(250,730)
	4561060	Transmission Enhancement Charges	95,608	95,608	95,608	95,608	95,608	95,608	98,683	98,683	98,683	98,683	98,683	98,683	1,165,747
	5650012	Transmission Enhancement Charges	166,448	165,966	166,052	166,052	165,965	141,935	2,169,658	146,210	(1,867,714)	146,310	144,434	123,767	1,835,083
	5650016	PJM NITS Expense - Affilated	4,298,169	4,298,169	4,159,095	4,298,169	4,159,095	4,298,169	5,076,547	4,583,779	5,076,547	4,912,291	5,076,547	4,912,291	55,148,870
	5650019	Transmission Enhancement Charges	446,305	446,305	446,305	446,305	446,305	446,305	429,586	429,586	429,586	429,586	429,586	429,586	5,255,347
			8,885,585	8,845,904	8,645,054	8,971,327	8,617,802	8,827,703	11,895,686	8,973,152	7,898,990	9,632,077	9,914,761	9,599,376	110,707,418
		(Over) Under Recovery of PJM OATT LSE Charges	$ 810,877	$ 771,196	$ 570,346	$ 896,619	$ 543,094	$ 752,995	$ 3,820,978	$ 898,444	$ (175,718)	$ 1,557,369	$ 1,840,053	$ 1,524,668	$ 13,810,922.38
		Previously 80%, now 100% above or below recovery in base rates allowable for recovery	$ 810,877	$ 771,196	$ 570,346	$ 896,619	$ 543,094	$ 752,995	$ 3,820,978	$ 898,444	$ (175,718)	$ 1,557,369	$ 1,840,053	$ 1,524,668	$ 13,810,922.38
		FERC Return in excess of Kentucky Retail Return	$ 17,381	$ 17,381	$ 17,381	$ 17,381	$ 17,381	$ 17,381	$ 33,926	$ 33,926	$ 33,926	$ 33,926	$ 33,926	$ 33,926	307,846
		Recovery of Declining Deferral of Rockport Costs (UPDATE Every January through 2022)	$ 833,333	$ 833,333	$ 833,333	$ 833,333	$ 833,333	$ 833,333	$ 833,333	$ 833,333	$ 833,333	$ 833,333	$ 833,333	$ 833,333	10,000,000
		Recovery of Amortization of Interest Expense Deferral (October 2021-September 2022)	$ -	$ -	$ -	$ 54,176	$ 54,176	$ 54,176	$ 54,176	$ 54,176	$ 54,176	$ 54,176	$ 54,176	$ 54,176	487,582
		Non-OATT LSE amount in base rates	$ 105,767	$ 105,767	$ 105,767	$ 105,767	$ 105,767	$ 105,767	$ 105,767	$ 105,767	$ 105,767	$ 105,767	$ 105,767	$ 105,767	1,269,204
		ESTIMATE - Day 3 - 100% of Interruptible Service Credits & Forced Outage Related Purchase Power Expense	$ 189,664	$ 54,707	$ 947,412	$ 1,034,543	$ 395,807	$ 755,729	$ 774,443	$ 37,245	$ 1,471,362	$ 89,869	$ 426,654	$ 94,990	
		Reversal of Day 3 estimates	$ (255,255)	$ (189,664)	$ (54,707)	$ (947,412)	$ (1,034,543)	$ (395,807)	$ (755,729)	$ (774,443)	$ (37,245)	$ (1,471,362)	$ (89,869)	$ (426,654)	
		ACTUALS - Post Close - True up of Prior Month 100% of Interruptible Service Credits & FO Expense	$ 254,980	$ 189,598	$ 54,695	$ 948,940	$ 1,035,227	$ 394,854	$ 806,746	$ 772,450	$ 37,259	$ 1,472,748	$ 89,932	$ 427,569	
		Total Non-OATT LSE at 100%	$ 189,389	$ 54,641	$ 947,400	$ 1,036,071	$ 396,491	$ 754,776	$ 825,460	$ 35,252	$ 1,471,376	$ 91,254	$ 426,717	$ 95,906	6,324,732
		Total Non-OATT LSE at 100% less amount in Base Rates	$ 83,622	$ (51,126)	$ 841,632	$ 930,304	$ 290,724	$ 649,009	$ 719,693	$ (70,515)	$ 1,365,609	$ (14,513)	$ 320,950	$ (9,861)	5,055,527
		(Over) Under Recovery of Base Rates (Step 1)	$ 877,118	$ 702,689	$ 1,394,597	$ 1,863,718	$ 870,612	$ 1,438,798	$ 4,560,920	$ 848,178	$ 1,210,141	$ 1,563,105	$ 2,181,252	$ 1,535,057	19,046,187
		Current month (Over) Under Recovery of Base Rates	$ (282,739)	$ (760,752)	$ 652,964	$ 299,826	$ (1,065,865)	$ (907,676)	$ 2,172,292	$ (1,171,076)	$ (661,850)	$ (109,970)	$ (186,337)	$ 238,150	(1,783,033)
		Cummulative Balance in Regulatory Asset/(Liability)	$ 26,341,931	$ 26,414,512	$ 27,900,809	$ 29,033,969	$ 28,801,437	$ 28,727,095	$ 31,732,721	$ 31,394,978	$ 31,566,461	$ 32,289,824	$ 32,936,820	$ 34,008,304	$ 29,046,186.55
														$ 34,008,304	accounting file

PPA - Form 4.0

Kentucky Power Company
PPA Revenue Collected
12 -Month Period ended June 30, 2022

Line	Tariff Class	Total for Over/Under
(1)	RES	10,393,896
(2)	GS (Includes SGS-TOD and MGS-TOD)	2,655,395
(3)	LGS	1,901,797
(4)	LGS LMTOD	7,066
(5)	IGS	5,293,361
(6)	MW	5,392
(7)	OL	22,745
(8)	SL	5,136
(9)	**Subtotal - Billed Revenue**	20,284,788
(10)	**Estimated, Unbilled & Gross-up**	671,339
(11)	**Total Revenue Collected**	**20,956,127**

PPA Rider Base Rate Amounts
12 Months Ended February 28, 2017
KPCo KY Retail Jurisdiction

PPA - Form 5.0

Line	Account	Description	Adjusted Test Year Total		Classification
(1)	4561005	PJM Point to Point Trans Svc		($535,143)	Demand
(2)	4561002	RTO Formation Cost Recovery		$196,296	Demand
(3)	4561035	PJM Affiliated Trans NITS Cost		$45,453,207	Demand
(4)	4561036	PJM Affiliated Trans TO Cost		$566,356	Energy
(5)	4561060	Affil PJM Trans Enhancmnt Cost		$788,524	Demand
(6)	5650012	PJM Trans Enhancement Charge		$5,035,193	Demand
(7)	5650016	PJM NITS Expense - Affiliated		$18,568,254	Demand
(8)	5650019	Affil PJM Trans Enhncement Exp		$3,965,830	Demand
(9)	PJM LSE OATT Base Amount			$74,038,517	
(9a)*	PJM LSE OATT Monthly Base Amount			**$6,169,876**	
(10)	Forced Outage Purchase Power Limitation Base Amount - Acct 555		$	372,542	Energy
(11)	CS IRP Credits Base Amount - Acct 44X		$	42,026	Demand
(11a)*	Non-PJM LSE OATT Monthly Base Amount		**$**	**34,547**	
(12)*	**Total PPA Base Amount**		**$**	**74,453,085**	
(13)	Monthly PPA Base Amount to be used for Periods less than 12 months (Line 12/12)			**$6,204,424**	

***Separated the monthly base amount to properly account for the 80% incremental recovery of PJM LSE OATT Costs**

FERC vs KY Retail ROE Delta Return Calculation

				Source
a	TO Transmission Rate Base	$	300,309,183	2018 OATT TCOS - Updated for settlement in docket EL17-13
b	KY Juris Retail Demand Factor		0.985	2017-00179 Section V, Allocation Factors
c = a*b	KY Retail TO Trans Rate Base	$	295,804,545	calculation
d	Base Rate KY Retail Trans Rate Base	$	266,193,975	2017-00179 Class Cost of Service
e = c-d	Difference	$	29,610,570	calculation
f	TO WACC @ 10.35 ROE		7.049%	2018 OATT TCOS - Updated for settlement in docket EL17-13
g	TO WACC @ 9.70 ROE		6.757%	2018 OATT TCOS - Updated for PSC Order
h = f-g	Difference		0.2914%	calculation
j = e*h	TO Return Delta	$	86,297	calculation
k	GRCF		1.3453	2018 OATT TCOS - Updated for 21% FIT Rate
l= j*k	***2018 Tariff PPA Revenue Credit***	***$***	***116,096***	calculation
m	Monthly Amount to be used for Periods less than 12 months (Line 11/12)		**$9,675**	

a	TO Transmission Rate Base	$	342,717,085	2019 OATT TCOS
b	KY Juris Retail Demand Factor		0.985	2017-00179 Section V, Allocation Factors
c = a*b	KY Retail TO Trans Rate Base	$	337,576,329	calculation
d	Base Rate KY Retail Trans Rate Base	$	266,193,975	2017-00179 Class Cost of Service
e = c-d	Difference	$	71,382,354	calculation
f	TO WACC @ 10.35 ROE		7.210%	2019 OATT TCOS
g	TO WACC @ 9.70 ROE		6.757%	2018 OATT TCOS
h = f-g	Difference		0.4526%	calculation
j = e*h	TO Return Delta	$	323,041	calculation
k	GRCF		1.3351	2019 OATT TCOS
l= j*k	***2019 Tariff PPA Revenue Credit***	***$***	***431,292***	calculation
m	Monthly Amount to be used for Periods less than 12 months (Line 11/12)		**$35,941**	

Class Billing Determinants
12 -Month Period ended June 30, 2022
Biling units are 12 months

Class	Billing Energy	Billing Demand
RES	1,950,552,428	N/A
GS (SGS/MGS)	621,062,180	N/A
LGS	493,155,443	1,502,999
LGS LMTOD	1,818,646	N/A
IGS	2,088,777,292	3,458,695
MW	1,830,736	N/A
OL	39,967,390	N/A
SL	8,444,372	N/A
Total	**5,205,608,487**	**4,961,694**

KENTUCKY POWER COMPANY
Gross Revenue Conversion

LINE NO.	Component	Balances	Cap. Structure	Cost Rates		WACC (Net of Tax)	GRCF	WACC (PRE-TAX)
		As of 2/28/2017*						
1	L/T DEBT	$648,913,758	53.45%	4.36%		2.33%	1.005425	2.34%
2	S/T DEBT	$0	3.20%	1.25%		0.04%	1.005425	0.04%
3	ACCTS REC FINANCING	$46,105,009	1.67%	1.95%		0.03%	1.005425	0.03%
4	C EQUITY	$496,766,726	41.68%	**9.70%**	**	4.04%	**1.352116**	5.46%
5	TOTAL	**$1,191,785,493**	**100.00%**					**7.88%**

		Debt	Equity
6	Operating Revenues	100.0000	100.0000
7	Less Uncollectible Accounts Expense	0.3400	0.3400
8	KPSC Maintenance Assessment Fee	0.1996	0.1996
9	Income Before Income Taxes	99.4604	99.4604
10	Less State Income Taxes (Ln 4 x 5.7348)		5.8425
11	Income Before Federal Income Taxes		93.6179
12	Less Federal Income Taxes (Ln 13*21%)		19.6598
13	Operating Income Percentage		73.9581
14	Gross Up Factor (100.00/Ln 9)	1.005425	1.3521

WACC	7.62%
Monthly	0.6350%
Monthly Payment	$1,128,292
Retail Revenue Requirement	$13,539,510

Line	Month	Additions	Levelized Payment	Calculated Change in RA	Month End Reg Asset Balance Excl. CC	ADIT on RA	ADIT Balance	Balance of Components Subject to WACC	Carrying Charges on Principal net of ADIT only	Carrying Charges on Total Reg Asset net of ADIT	Month End Reg Asset Balance
					-		-	-			-
1	January-18	524,194		524,194	524,194	(110,081)	(110,081)	414,113			524,194
2	February-18	1,250,000		1,250,000	1,774,194	(262,500)	(372,581)	1,401,613	3,442		1,777,636
3	March-18	1,250,000		1,250,000	3,024,194	(262,500)	(635,081)	2,389,113	9,204		3,036,840
4	April-18	1,250,000		1,250,000	4,274,194	(262,500)	(897,581)	3,376,613	15,689		4,302,528
5	May-18	1,250,000		1,250,000	5,524,194	(262,500)	(1,160,081)	4,364,113	22,173		5,574,701
6	June-18	1,250,000		1,250,000	6,774,194	(262,500)	(1,422,581)	5,351,613	28,658		6,853,359
7	July-18	1,250,000		1,250,000	8,024,194	(262,500)	(1,685,081)	6,339,113	35,142		8,138,501
8	August-18	1,250,000		1,250,000	9,274,194	(262,500)	(1,947,581)	7,326,613	41,627		9,430,128
9	September-18	1,250,000		1,250,000	10,524,194	(262,500)	(2,210,081)	8,314,113	48,111		10,728,239
10	October-18	1,250,000		1,250,000	11,774,194	(262,500)	(2,472,581)	9,301,613	54,596		12,032,835
11	November-18	1,250,000		1,250,000	13,024,194	(262,500)	(2,735,081)	10,289,113	61,081		13,343,916
12	December-18	1,250,000		1,250,000	14,274,194	(262,500)	(2,997,581)	11,276,613	67,565		14,661,481
13	January-19	1,250,000		1,250,000	15,524,194	(262,500)	(3,260,081)	12,264,113	74,050		15,985,531
14	February-19	1,250,000		1,250,000	16,774,194	(262,500)	(3,522,581)	13,251,613	80,534		17,316,065
15	March-19	1,250,000		1,250,000	18,024,194	(262,500)	(3,785,081)	14,239,113	87,019		18,653,084
16	April-19	1,250,000		1,250,000	19,274,194	(262,500)	(4,047,581)	15,226,613	93,504		19,996,588
17	May-19	1,250,000		1,250,000	20,524,194	(262,500)	(4,310,081)	16,214,113	99,988		21,346,576
18	June-19	1,250,000		1,250,000	21,774,194	(262,500)	(4,572,581)	17,201,613	106,473		22,703,049
19	July-19	1,250,000		1,250,000	23,024,194	(262,500)	(4,835,081)	18,189,113	112,957		24,066,006
20	August-19	1,250,000		1,250,000	24,274,194	(262,500)	(5,097,581)	19,176,613	119,442		25,435,448
21	September-19	1,250,000		1,250,000	25,524,194	(262,500)	(5,360,081)	20,164,113	125,926		26,811,374
22	October-19	1,250,000		1,250,000	26,774,194	(262,500)	(5,622,581)	21,151,613	132,411		28,193,785
23	November-19	1,250,000		1,250,000	28,024,194	(262,500)	(5,885,081)	22,139,113	138,896		29,582,681
24	December-19	1,250,000		1,250,000	29,274,194	(262,500)	(6,147,581)	23,126,613	145,380		30,978,061
25	January-20	833,333		833,333	30,107,527	(175,000)	(6,322,581)	23,784,946	151,865		31,963,259
26	February-20	833,333		833,333	30,940,860	(175,000)	(6,497,581)	24,443,280	156,188		32,952,780
27	March-20	833,333		833,333	31,774,194	(175,000)	(6,672,581)	25,101,613	160,511		33,946,624
28	April-20	833,333		833,333	32,607,527	(175,000)	(6,847,581)	25,759,946	164,834		34,944,791
29	May-20	833,333		833,333	33,440,860	(175,000)	(7,022,581)	26,418,280	169,157		35,947,282
30	June-20	833,333		833,333	34,274,194	(175,000)	(7,197,581)	27,076,613	173,480		36,954,095
31	July-20	833,333		833,333	35,107,527	(175,000)	(7,372,581)	27,734,946	177,803		37,965,232
32	August-20	833,333		833,333	35,940,860	(175,000)	(7,547,581)	28,393,280	182,126		38,980,691
33	September-20	833,333		833,333	36,774,194	(175,000)	(7,722,581)	29,051,613	186,449		40,000,474
34	October-20	833,333		833,333	37,607,527	(175,000)	(7,897,581)	29,709,946	190,772		41,024,579
35	November-20	833,333		833,333	38,440,860	(175,000)	(8,072,581)	30,368,280	195,095		42,053,008
36	December-20	833,333		833,333	39,274,194	(175,000)	(8,247,581)	31,026,613	199,418		43,085,760
37	January 2021 Prorate								85,440		43,171,199
38	January 2021 Prorate	416,667		416,667	39,690,860	(87,500)	(8,335,081)	31,355,780	114,398		43,702,264
39	February-21	416,667		416,667	40,107,527	(87,500)	(8,422,581)	31,684,946	199,109		44,318,040
40	March-21	416,667		416,667	40,524,193	(87,500)	(8,510,081)	32,014,113	201,199		44,935,906
41	April-21	416,667		416,667	40,940,860	(87,500)	(8,597,581)	32,343,280	203,290		45,555,862
42	May-21	416,667		416,667	41,357,527	(87,500)	(8,685,081)	32,672,446	205,380		46,177,909
43	June-21	416,667		416,667	41,774,193	(87,500)	(8,772,581)	33,001,613	207,470		46,802,046
44	July-21	416,667		416,667	42,190,860	(87,500)	(8,860,081)	33,330,780	209,560		47,428,273
45	August-21	416,667		416,667	42,607,527	(87,500)	(8,947,581)	33,659,946	211,650		48,056,590
46	September-21	416,667		416,667	43,024,193	(87,500)	(9,035,081)	33,989,113	213,741		48,686,997
47	October-21	416,667		416,667	43,440,860	(87,500)	(9,122,581)	34,318,279	215,831		49,319,494
48	November-21	416,667		416,667	43,857,527	(87,500)	(9,210,081)	34,647,446	217,921		49,954,082
49	December-21	416,667		416,667	44,274,193	(87,500)	(9,297,581)	34,976,613	220,011		50,590,760
50	January-22	416,667		416,667	44,690,860	(87,500)	(9,385,081)	35,305,779	222,101		51,229,528
51	February-22	416,667		416,667	45,107,527	(87,500)	(9,472,581)	35,634,946	224,192		51,870,387
52	March-22	416,667		416,667	45,524,193	(87,500)	(9,560,081)	35,964,113	226,282		52,513,335
53	April-22	416,667		416,667	45,940,860	(87,500)	(9,647,581)	36,293,279	228,372		53,158,374
54	May-22	416,667		416,667	46,357,527	(87,500)	(9,735,081)	36,622,446	230,462		53,805,503
55	June-22	416,667		416,667	46,774,193	(87,500)	(9,822,581)	36,951,613	232,553		54,454,722
56	July-22	416,667		416,667	47,190,860	(87,500)	(9,910,081)	37,280,779	234,643		55,106,032
57	August-22	416,667		416,667	47,607,527	(87,500)	(9,997,581)	37,609,946	236,733		55,759,431
58	September-22	416,667		416,667	48,024,193	(87,500)	(10,085,081)	37,939,113	238,823		56,414,921
59	October-22	416,667		416,667	48,440,860	(87,500)	(10,172,581)	38,268,279	240,913		57,072,501
60	November-22	416,667		416,667	48,857,527	(87,500)	(10,260,081)	38,597,446	243,004		57,732,171
61	Dec 1 - Dec 8, 2022	107,527		107,527	48,965,054	(22,581)	(10,282,661)	38,682,392	63,250		57,902,948
62	Dec 9 - Dec 31, 2022		837,120	(837,120)		127,151	(10,155,510)	47,134,671		224,353	57,290,181
63	January-23		1,128,292	(1,128,292)		171,378	(9,984,132)	46,477,061		299,305	56,461,194
64	February-23		1,128,292	(1,128,292)		171,378	(9,812,755)	45,815,276		295,129	55,628,031
65	March-23		1,128,292	(1,128,292)		171,378	(9,641,377)	45,149,288		290,927	54,790,665
66	April-23		1,128,292	(1,128,292)		171,378	(9,469,999)	44,479,071		286,698	53,949,071
67	May-23		1,128,292	(1,128,292)		171,378	(9,298,622)	43,804,599		282,442	53,103,220
68	June-23		1,128,292	(1,128,292)		171,378	(9,127,244)	43,125,843		278,159	52,253,087
69	July-23		1,128,292	(1,128,292)		171,378	(8,955,866)	42,442,777		273,849	51,398,644
70	August-23		1,128,292	(1,128,292)		171,378	(8,784,489)	41,755,374		269,512	50,539,863
71	September-23		1,128,292	(1,128,292)		171,378	(8,613,111)	41,063,606		265,147	49,676,717

WACC	7.62%
Monthly	0.6350%
Monthly Payment	$1,128,292
Retail Revenue Requirement	$13,539,510

Line	Month	Additions	Levelized Payment	Calculated Change in RA	Month End Reg Asset Balance Excl. CC	ADIT on RA	ADIT Balance	Balance of Components Subject to WACC	Carrying Charges on Principal net of ADIT only	Carrying Charges on Total Reg Asset net of ADIT	Month End Reg Asset Balance
72	October-23		1,128,292	(1,128,292)		171,378	(8,441,733)	40,367,445		260,754	48,809,178
73	November-23		1,128,292	(1,128,292)		171,378	(8,270,355)	39,666,864		256,333	47,937,219
74	December-23		1,128,292	(1,128,292)		171,378	(8,098,978)	38,961,833		251,885	47,060,811
75	January-24		1,128,292	(1,128,292)		171,378	(7,927,600)	38,252,326		247,408	46,179,926
76	February-24		1,128,292	(1,128,292)		171,378	(7,756,222)	37,538,314		242,902	45,294,536
77	March-24		1,128,292	(1,128,292)		171,378	(7,584,845)	36,819,767		238,368	44,404,612
78	April-24		1,128,292	(1,128,292)		171,378	(7,413,467)	36,096,658		233,806	43,510,125
79	May-24		1,128,292	(1,128,292)		171,378	(7,242,089)	35,368,957		229,214	42,611,046
80	June-24		1,128,292	(1,128,292)		171,378	(7,070,712)	34,636,635		224,593	41,707,347
81	July-24		1,128,292	(1,128,292)		171,378	(6,899,334)	33,899,663		219,943	40,798,997
82	August-24		1,128,292	(1,128,292)		171,378	(6,727,956)	33,158,011		215,263	39,885,967
83	September-24		1,128,292	(1,128,292)		171,378	(6,556,579)	32,411,650		210,553	38,968,228
84	October-24		1,128,292	(1,128,292)		171,378	(6,385,201)	31,660,549		205,814	38,045,750
85	November-24		1,128,292	(1,128,292)		171,378	(6,213,823)	30,904,679		201,044	37,118,502
86	December-24		1,128,292	(1,128,292)		171,378	(6,042,446)	30,144,009		196,245	36,186,454
87	January-25		1,128,292	(1,128,292)		171,378	(5,871,068)	29,378,508		191,414	35,249,576
88	February-25		1,128,292	(1,128,292)		171,378	(5,699,690)	28,608,147		186,554	34,307,837
89	March-25		1,128,292	(1,128,292)		171,378	(5,528,312)	27,832,894		181,662	33,361,206
90	April-25		1,128,292	(1,128,292)		171,378	(5,356,935)	27,052,718		176,739	32,409,653
91	May-25		1,128,292	(1,128,292)		171,378	(5,185,557)	26,267,588		171,785	31,453,145
92	June-25		1,128,292	(1,128,292)		171,378	(5,014,179)	25,477,472		166,799	30,491,652
93	July-25		1,128,292	(1,128,292)		171,378	(4,842,802)	24,682,340		161,782	29,525,141
94	August-25		1,128,292	(1,128,292)		171,378	(4,671,424)	23,882,158		156,733	28,553,582
95	September-25		1,128,292	(1,128,292)		171,378	(4,500,046)	23,076,895		151,652	27,576,941
96	October-25		1,128,292	(1,128,292)		171,378	(4,328,669)	22,266,518		146,538	26,595,187
97	November-25		1,128,292	(1,128,292)		171,378	(4,157,291)	21,450,996		141,392	25,608,287
98	December-25		1,128,292	(1,128,292)		171,378	(3,985,913)	20,630,295		136,214	24,616,208
99	January-26		1,128,292	(1,128,292)		171,378	(3,814,536)	19,804,382		131,002	23,618,918
100	February-26		1,128,292	(1,128,292)		171,378	(3,643,158)	18,973,225		125,758	22,616,383
101	March-26		1,128,292	(1,128,292)		171,378	(3,471,780)	18,136,791		120,480	21,608,571
102	April-26		1,128,292	(1,128,292)		171,378	(3,300,403)	17,295,044		115,169	20,595,447
103	May-26		1,128,292	(1,128,292)		171,378	(3,129,025)	16,447,953		109,824	19,576,978
104	June-26		1,128,292	(1,128,292)		171,378	(2,957,647)	15,595,483		104,445	18,553,130
105	July-26		1,128,292	(1,128,292)		171,378	(2,786,269)	14,737,599		99,031	17,523,869
106	August-26		1,128,292	(1,128,292)		171,378	(2,614,892)	13,874,268		93,584	16,489,160
107	September-26		1,128,292	(1,128,292)		171,378	(2,443,514)	13,005,455		88,102	15,448,969
108	October-26		1,128,292	(1,128,292)		171,378	(2,272,136)	12,131,125		82,585	14,403,262
109	November-26		1,128,292	(1,128,292)		171,378	(2,100,759)	11,251,243		77,033	13,352,002
110	December-26		1,128,292	(1,128,292)		171,378	(1,929,381)	10,365,774		71,445	12,295,155
111	January-27		1,128,292	(1,128,292)		171,378	(1,758,003)	9,474,681		65,823	11,232,685
112	February-27		1,128,292	(1,128,292)		171,378	(1,586,626)	8,577,931		60,164	10,164,557
113	March-27		1,128,292	(1,128,292)		171,378	(1,415,248)	7,675,486		54,470	9,090,734
114	April-27		1,128,292	(1,128,292)		171,378	(1,243,870)	6,767,311		48,739	8,011,181
115	May-27		1,128,292	(1,128,292)		171,378	(1,072,493)	5,853,368		42,972	6,925,861
116	June-27		1,128,292	(1,128,292)		171,378	(901,115)	4,933,622		37,169	5,834,737
117	July-27		1,128,292	(1,128,292)		171,378	(729,737)	4,008,036		31,329	4,737,773
118	August-27		1,128,292	(1,128,292)		171,378	(558,360)	3,076,572		25,451	3,634,932
119	September-27		1,128,292	(1,128,292)		171,378	(386,982)	2,139,194		19,536	2,526,176
120	October-27		1,128,292	(1,128,292)		171,378	(215,604)	1,195,863		13,584	1,411,467
121	November-27		1,128,292	(1,128,292)		171,378	(44,226)	246,542		7,594	290,768
122	Dec 1 - Dec 8, 2027		291,172	(291,172)		44,226	0	(0)		404	(0)
	Totals	48,965,054	67,697,548	(18,732,494)		0			8,937,895	9,794,600	

Kentucky Power Company
Rockport Savings-Offset

(1) Rockport Fixed Cost Savings

Amount of Rockport Fixed Cost in Base Rates	$	40,831,141

(2) 2023 Rockport Offset Calculation

	Calculation		Rockport Offset ***Estimated***	Rockport Offset ***Actual***	***Source***
a	12 Month Net GAAP Income	$	65,090,127	Available Q1 2024	Estimate - Q2 2022 Per Books as Reported SEC Kentucky Power Company Actual - Q4 2023 Per Books as Reported SEC Kentucky Power Company
b	13 Month Average Common Equity	$	881,014,064	Available Q1 2024	Estimate - Q2 2022 Per Books as Reported SEC Kentucky Power Company Actual - Q4 2023 Per Books as Reported SEC Kentucky Power Company
c = a/b	Return on Common Equity		7.39%	Available Q1 2024	Calculation
d	Kentucky Power Allowed Retail ROE		9.30%		Commission Order in Case No. 2020-00174
	If D < C, Stop If D > C, Continue to Part e				
e = (b*d)-a	Net GAAP Income Increase Required to Earn Allowed Retail ROE	$	16,844,181	Available Q1 2024	Calculation
f	Gross Revenue Conversion Factor		1.352731		Commission Order in Case No. 2020-00174
g = e*f	Rockport Offset	$	22,785,645	Available Q1 2024	Calculation
= g	***Amount to Be Recovered Through Tariff PPA***	***$***	***22,785,645***		

(3) 2024 Rockport Offset True-up (Actual - Estimate) Available Q1 2024

TARIFF P.P.A. (Cont'd)
(Purchase Power Adjustment)

RATES.

Tariff Class	$/kWh	$/kW
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.	$0.00353~~729~~	--
S.G.S.-T.O.D.	$0.00288~~595~~	--
M.G.S.-T.O.D.	$0.00288~~595~~	--
G.S.	$0.00288~~595~~	--
L.G.S., L.G.S.-T.O.D.	$0.0001~~4~~30	$~~1~~0.82~~70~~
L.G.S.-L.M.-T.O.D.	$0.00265~~548~~	--
I.G.S. and C.S.-I.R.P.	$0.0001~~4~~30	$1~~2~~.0~~1~~4
M.W.	$0.00199~~412~~	--
O.L.	$0.00051~~105~~	--
S.L.	$0.00051~~105~~	--

R

The kWh factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW factor as calculated above will be applied to all on-peak and minimum billing demand kW for the LGS, LGS-T.O.D, IGS, and CS-I.R.P. tariff classes.

The Purchase Power Adjustment factors shall be modified annually using the following formula:

The Purchase Power Adjustment factors shall be determined as follows:

For all tariff classes without demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total}) + PPA(D) \times (CP_{Class} / CP_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = 0$$

For all tariff classes with demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = \frac{PPA(D) \times (CP_{Class/} / CP_{Total})}{BD_{Class}}$$

(Cont'd on Sheet No. 35-3)

DATE OF ISSUE: ~~August 12, 2022~~November 15, 2022
DATE EFFECTIVE: Service Rendered On And After ~~September 28~~December 9, 2022
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority Of an Order of the Public Service Commission
In Case No. 2017~~XXXX~~-00179~~XXXXX~~ Dated ~~XXXX XX~~January 18, 2018~~XXXX~~

TARIFF P.P.A. (Cont'd)
(Purchase Power Adjustment)

RATES.

Tariff Class	$/kWh	$/kW
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.	$0.00353	--
S.G.S.-T.O.D.	$0.00288	--
M.G.S.-T.O.D.	$0.00288	--
G.S.	$0.00288	--
L.G.S., L.G.S.-T.O.D.	$0.00014	$0.82
L.G.S.-L.M.-T.O.D.	$0.00265	--
I.G.S. and C.S.-I.R.P.	$0.00014	$1.04
M.W.	$0.00199	--
O.L.	$0.00051	--
S.L.	$0.00051	--

R

The kWh factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW factor as calculated above will be applied to all on-peak and minimum billing demand kW for the LGS, LGS-T.O.D, IGS, and CS-I.R.P. tariff classes.

The Purchase Power Adjustment factors shall be modified annually using the following formula:

The Purchase Power Adjustment factors shall be determined as follows:

For all tariff classes without demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total}) + PPA(D) \times (CP_{Class} / CP_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = 0$$

For all tariff classes with demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = \frac{PPA(D) \times (CP_{Class/} / CP_{Total})}{BD_{Class}}$$

(Cont'd on Sheet No. 35-3)

DATE OF ISSUE: November 15, 2022
DATE EFFECTIVE: Service Rendered On And After December 9, 2022
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority Of an Order of the Public Service Commission
In Case No. 2017-00179 Dated January 18, 2018

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application of Kentucky Power	)	
Company For (1) A General Adjustment Of Its	)	
Rates for Electric Service; (2) An Order	)	
Approving Its 2017 Environmental Compliance	)	
Plan; (3) An Order Approving Its Tariffs And	)	Case No. 2017-00179
Riders; (4) An Order Approving Accounting	)	
Practices To Establish Regulatory Assets And	)	
Liabilities; And (5) An Order Granting All Other	)	
Required Approvals And Relief	)	

REBUTTAL TESTIMONY OF

ADRIEN M. MCKENZIE, CFA

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Adrien M. McKenzie being duly sworn deposes and says he is the Vice President of FINCAP, Inc., and that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Adrien M .McKenzie

STATE OF TEXAS)
) Case No. 2017-00179
COUNTY OF TRAVIS)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by, Adrien M .McKenzie this 2nd day of November 2017.

ROBERT LEE MARTINEZ
NOTARY PUBLIC STATE OF TEXAS
MY COMM. EXP. 4/17/2019
NOTARY ID 13019391-2

Notary Public

My Commission Expires: 04/17/2019

REBUTTAL TESTIMONY OF

ADRIEN M. MCKENZIE

TABLE OF CONTENTS

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. Adrien M. McKenzie, 3907 Red River, Austin, Texas, 78751.

Q2. ARE YOU THE SAME ADRIEN M. MCKENZIE THAT PREVIOUSLY SUBMITTED PREFILED DIRECT TESTIMONY IN THIS CASE?

A2. Yes, I am.

Q3. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A3. My testimony to the Kentucky Public Service Commission ("KPSC" or the "Commission") addresses the testimony of Dr. J. Randall Woolridge, submitted on behalf of the Kentucky Office of Attorney General ("OAG"), Mr. Richard Baudino, on behalf of the Kentucky Industrial Utility Consumers, Inc. ("KIUC"), and Mr. Gregory W. Tillman, on behalf of Wal-Mart Stores East, LP and Sam's East, Inc. ("Wal-Mart"),[1] concerning the fair rate of return on equity ("ROE") that Kentucky Power Company ("Kentucky Power" or "the Company") should be authorized to earn on their investment in providing electric utility service.

Q4. HAVE YOU PREPARED WORKPAPERS SUPPORTING YOUR REBUTTAL TESTIMONY?

A4. Yes. Workpapers including supporting documents referenced in my rebuttal testimony and related exhibits are attached as Appendix A.

A. Summary of Conclusions

Q5. PLEASE SUMMARIZE THE RECOMMENDATIONS OF THE ROE WITNESSES.

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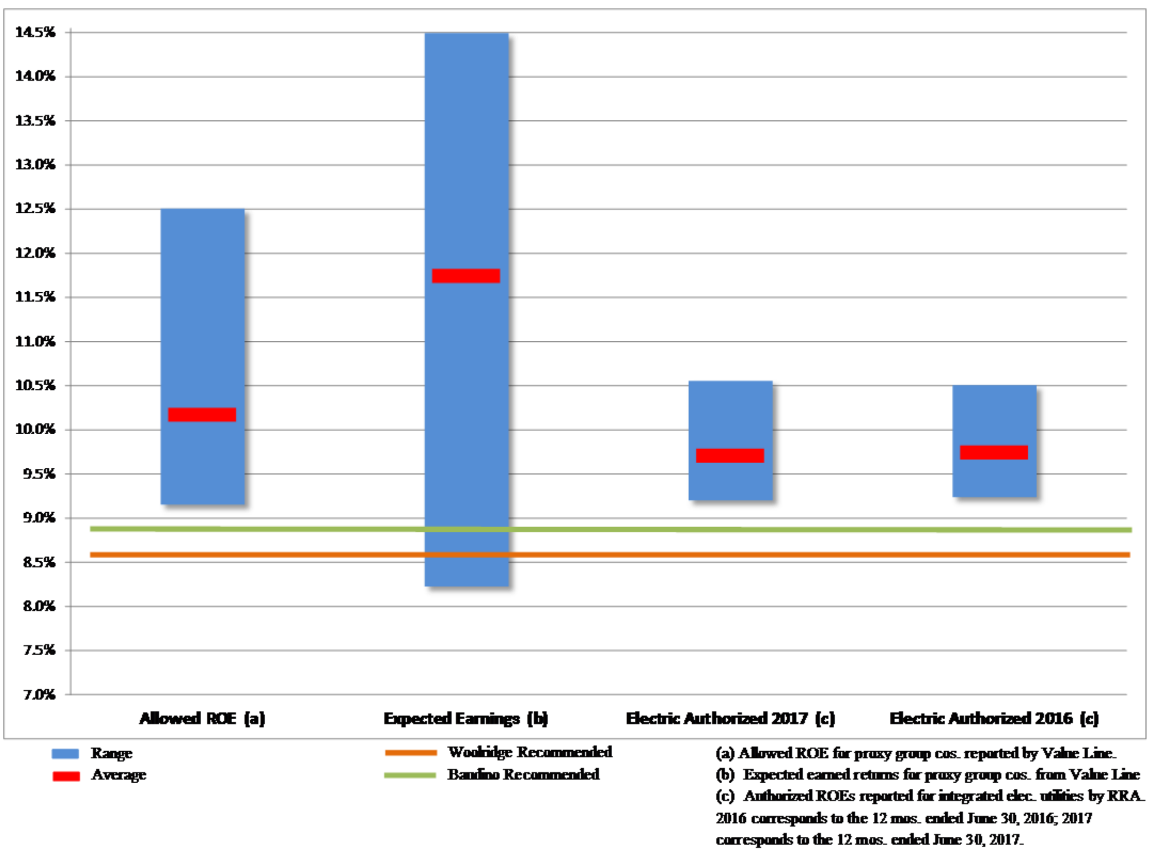
[1] I refer, collectively, to Dr. Woolridge and Mr. Baudino as the "ROE Witnesses" since they made specific ROE recommendations. Mr. Tillman testified generally about the ROE issue without making a specific proposal.

A5. Dr. Woolridge recommends an ROE of 8.60% for the Company, while Mr. Baudino proposes an ROE of 8.85%.

Q6. PLEASE SUMMARIZE YOUR RESPONSE TO THE ROE WITNESSES' TESTIMONY.

A6. Their cost of equity recommendations are simply too low and fail to reflect the risk perceptions and return requirements of real-world investors in the capital markets. The significant shortfall between their recommendations and the ROE benchmarks discussed in my rebuttal testimony are illustrated in the figure below.

FIGURE R-1
COMPARISON OF ROE RECOMMENDATIONS TO BENCHMARKS



Q7. WHAT ARE YOUR PRINCIPAL CONCLUSIONS REGARDING THE RECOMMENDATIONS OF DR. WOOLRIDGE?

A7. I demonstrate that Dr. Woolridge's recommendations should be ignored in their entirety based on the following findings:

- Dr. Woolridge's recommended ROE of 8.60% is an extreme outlier and should be rejected on its face.
- Dr. Woolridge's discussion of current capital market conditions is potentially misleading.
- Dr. Woolridge's focus on market-to-book ratios ("M/B") is misguided and not relevant to the determination of reasonable ROEs in this case.
- The proxy group selected by Dr. Woolridge incorrectly excludes several utilities that should have been considered in his analyses.
- His Discounted Cash Flow ("DCF") analysis contains several flaws, including his reliance on dividend per share and historical data for estimating the DCF growth term, his inclusion of illogical results stemming from unrealistically low growth rates (including numerous negative growth rates), and his reference to growth in gross domestic product ("GDP") as an upper bound on utility company growth rates. As a result, his conclusions are unreliable and should be ignored.
- Dr. Woolridge's application of the DCF model based on the internal, "br" growth rate is flawed and incomplete,
- The Capital Asset Pricing Model ("CAPM") results reported by Dr. Woolridge are based on a hodge-podge of historical data that fail to reflect forward-looking expectations, particularly in light of current conditions in the capital markets.

Furthermore, Dr. Woolridge failed to consider the Empirical CAPM ("ECAPM") and risk premium approaches, which are legitimate ROE methods. His rejection of flotation costs is at odds with the conclusions of recognized financial research and his own admission that these are legitimate expenses that should be recovered. Finally, his criticisms of my size adjustment, market return calculation, expected earnings approach, and non-utility DCF analysis are without merit. Taken as a whole, these shortcomings ensure that Dr. Woolridge's recommended ROE falls well below a fair and reasonable level for the

Company's utility operations. In fact, his recommendation is so far below a reasonable ROE range that it should be rejected on its face.

Q8. WHAT ARE YOUR PRINCIPAL CONCLUSIONS REGARDING THE RECOMMENDATIONS OF MR. BAUDINO?

A8. Mr. Baudino's 8.85% ROE recommendation is also below realistic investor expectations. My rebuttal testimony demonstrates that:

- Mr. Baudino mistakenly excludes legitimate companies from his proxy group, casting doubt on his ROE conclusions.
- Mr. Baudino places too much emphasis on dividend growth and failed to evaluate the reasonableness of individual DCF estimates. As a result, his conclusions are unreliable and should be ignored.
- Mr. Baudino's application of the DCF model based on the internal, "br" growth rate is flawed and incomplete.
- Mr. Baudino's application of the CAPM was compromised by reliance on historical data, while his forward-looking approach was marred by methodological shortcomings and inconsistencies.
- Like Dr. Woolridge, Mr. Baudino's rejection of a flotation cost adjustment contradicts the findings of the financial literature and the economic requirements underlying a fair rate of return on equity.

Finally, my rebuttal testimony demonstrates that Mr. Baudino's criticisms of my alternative applications and conclusions are misguided and should be ignored.

B. Comparison of ROE Recommendations to Accepted Benchmarks

Q9. CAN YOU ILLUSTRATE THE EXTREME NATURE OF THE ROE WITNESSES' RECOMMENDATIONS?

A9. Yes. If adopted, the 8.60% ROE suggested by Dr. Woolridge and the 8.85% value offered by Mr. Baudino would be the lowest ROEs granted to a vertically-integrated electric utility by a state commission in recent history, if not ever.[2] These recommendations are significantly below the 9.70% ROE authorized for Kentucky Utilities Company and Louisville Gas and Electric Company by the Commission in June 2017.[3] These comparisons demonstrate that the recommendations of the ROE Witnesses would not meet the judicial standards underpinning a fair rate of return for Kentucky Power.

Q10. WHAT IS THE EXPECTED DIRECTION OF INTEREST RATES AND HOW DOES THIS IMPACT THE EVALUATION OF A FAIR ROE IN THIS PROCEEDING?

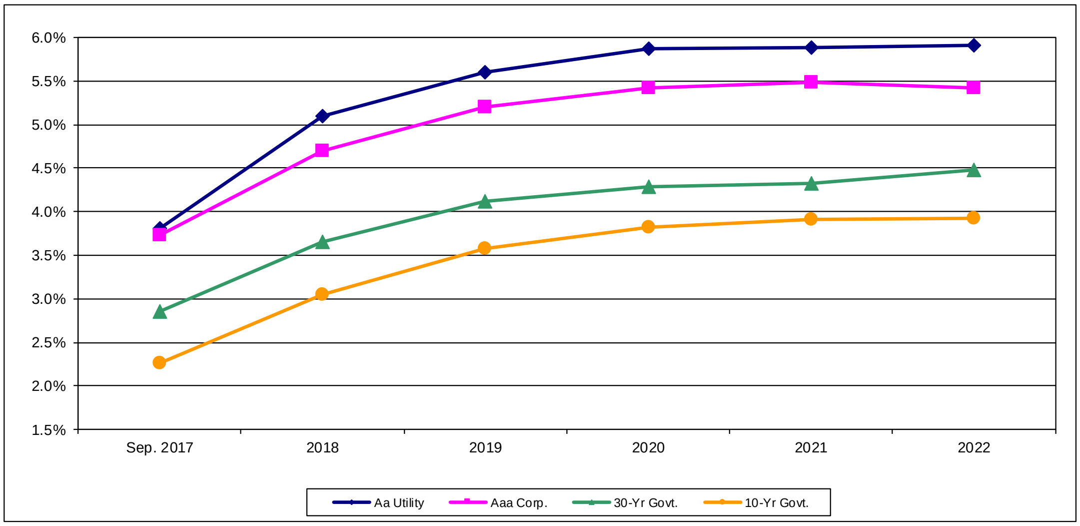
A10. Interest rates are expected to increase. Below is an update of Figure 3 (Interest Rate Trends) from my Direct Testimony:

---

[2] Regulatory Research Associated reported that Maui Electric was granted an ROE of 9.0% on May 31, 2013. However, the base ROE determined by the Public Utilities Commission of Hawaii was 9.50%, to which a 50 basis point penalty was applied due to "apparent system inefficiencies which negatively impact MECO's customers." (Docket No. 2011-0092, Decision and Order No. 31288, p, 107). Beyond that, the lowest authorized ROE for a vertically-integrated electric utility was 9.20% authorized for Northern States Power-Minnesota on May 11, 2017. As I discuss later in this testimony, this ROE award was accompanied by a number of risk-reducing regulatory mechanisms not available to the Company.

[3] Case Nos. 2016-00370 (Kentucky Utilities Company) and 2016-00371 (Louisville Gas and Electric Company), Final Order, June 22, 2017.

FIGURE R-2
PROJECTED INTEREST RATE TRENDS



Source:
Value Line Investment Survey, Forecast for the U.S. Economy (Sep. 1, 2017)
IHS Global Insight (Aug. 24, 2017)
Energy Information Administration, Annual Energy Outlook 2017 (Jan. 5, 2017)
Wolters Kluwer, Blue Chip Financial Forecasts, Vol. 36, No. 6 (Jun. 1, 2017)

As the figure shows, investors continue to anticipate that interest rates will increase significantly from present levels. These projections are from forecasting services that are highly regarded and widely referenced, as I discuss in my Direct Testimony (at 20-22). The interest rate increases shown in the figure above are on the order of 150-200 basis points through 2022, which implies higher long-term capital costs over the period when rates established in this proceeding will be in effect.

Q11. DID DR. WOOLRIDGE ACKNOWLEDGE THAT INTEREST RATES ARE EXPECTED TO INCREASE?

A11. Yes. In selecting the risk-free rate for use in his CAPM analysis, Dr. Woolridge states that "[g]iven the recent range of yields <u>and the possibility of higher interest rates</u>, I use the higher end 4.0% as the risk-free rate, or R_f, in my CAPM."[4] Given that the current 30-year U.S. Treasury bond rate (the rate Dr. Woolridge uses as

[4] Woolridge Direct at 50 (emphasis added).

the risk-free rate in his CAPM analysis) is around 2.9%, Dr. Woolridge clearly recognizes that investors anticipate a substantial increase in future interest rates.

Q12. WHAT DO THESE EXPECTATIONS IMPLY WITH RESPECT TO THE ROE FOR THE COMPANY MORE GENERALLY?

A12. Largely because of unprecedented Federal Reserve policies, current capital costs are not representative of what is likely to prevail over the near-term future. As indicated in my Direct Testimony,[5] regulators have recognized the shortcomings of the DCF approach. FERC has reiterated its position that current capital market conditions may undermine the reliability of the DCF model, and for this reason, ROE model results should be evaluated with even more critical judgment and focus:

> As described above, evidence in the record regarding historically low interest rates and Treasury bond yields as well as the Federal Reserve's large and persistent intervention in markets for debt securities are sufficient to find that current capital market conditions are anomalous.[6]
>
> Similarly, while Complainants provide evidence that interest rates have been trending downwards, the current levels may be so low as to cause irregularities in the outputs of the DCF. Despite such yields remaining low for several years, we find that they are anomalous and could distort the results of the DCF model.[7]

Current capital market conditions make the process of setting a fair ROE even more demanding. In this environment, it is imperative that ROE model results be thoroughly tested against accepted benchmarks and compared to other checks of reasonableness.

Q13. IS IT NECESSARY THAT INTEREST RATE FORECASTS, LIKE THOSE MENTIONED ABOVE, BE PERFECTLY ACCURATE IN ORDER TO BE RELIED UPON?

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[5] McKenzie Direct at 7-8, 22-23.
[6] Opinion No. 551, 156 FERC ¶ 61,234 at P 124 (2016).
[7] *Id.*

A13. Absolutely not. I dealt with this topic in my Direct Testimony (at 37-38) in discussing the validity of analysts' growth forecasts, and the same principle applies here. In estimating investors' required rate of return, what investors expect, not what actually happens, is what matters most. While the projections of various services may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing expected interest rates and how they might influence the Company's allowed ROE. Any difference in actual rates as compared to analysts' forecasts is beside the point. What is most important is that investors share analysts' views when the forecasts were made and incorporate those views into their decision making process, not the actual rates that ultimately transpire.

Q14. HOW DO THE ROE WITNESSES' RECOMMENDATIONS COMPARE TO RECENTLY-ALLOWED RETURNS FROM OTHER STATE COMMISSIONS?

A14. Allowed ROEs by other state commissions provide a general gauge of reasonableness for the outcome of a cost of equity analysis. In considering utilities with comparable risks, investors will always prefer to provide capital to the opportunity with the highest expected return. If a utility is unable to offer a return similar to that available from other investment opportunities posing equivalent risks, investors will become unwilling to supply the utility with capital on reasonable terms. While the ROEs approved in other jurisdictions do not constrain the Commission's decision-making in this proceeding, it is important to understand that there would be a disincentive for investors to provide equity capital to the Company if the Commission were to apply an unreasonably low ROE, compared to entities of comparable risk.

The recommendations of the ROE Witnesses are significantly below equity returns that have been allowed by other state regulatory commissions around the country. As shown on Exhibit No. 12, over the past 24 months ended

September 30, 2017, the average allowed ROE (excluding adders and penalties) reported by S&P Global (formerly Regulatory Research Associates) for vertically-integrated electric utilities is 9.73%,[8] with the midpoint of the high and low values being 9.88%. Similarly, authorized ROE data reported to investors by The Value Line Investment Survey ("Value Line") for the specific firms in my proxy group also indicate that the recommendations of the ROE Witnesses are insufficient.[9] As shown in Exhibit No. 13, these ROEs average 10.18%, with the midpoint of the lowest and highest values being 10.83%. In other words, allowed returns for the utilities that the ROE Witnesses generally consider comparable to the Company indicate that their recommendations are too low to meet regulatory standards.

Q15. MR. TILLMAN EXCLUSIVELY REFERENCES ROES AWARDED IN RECENT RATE CASES.[10] WOULD IT BE APPROPRIATE TO USE RECENT ALLOWED RETURNS TO ESTABLISH THE COMPANY'S ROE DIRECTLY?

A15. No. As discussed in my direct testimony (pp. 58-63), while allowed ROE data is a valuable "secondary" approach in judging whether an ROE estimate based on the application of accepted financial models makes sense, there is no basis to place undue weight on a single, summary statistic in lieu of comprehensive analyses and a case-specific evidentiary record. Setting a utility's ROE is a very company-specific process, and is a function of investors' perceptions of the risks and prospects for the subject company at a given point in time. As a result, the

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[8] For the 12 months ended September 30, 2017, the average is 9.71%; for the 12 months ended September 30, 2016, the average is 9.77%.

[9] Dr. Woolridge relies on my proxy group as one of his two electric groups, after removing Emera, Inc. and Fortis, Inc. due to his unexplained statement (fn. 18) that "they based on Canada" (sic). Likewise, Mr. Baudino starts with my group before removing three companies, AVANGRID, Inc., Emera, Inc., and Fortis, Inc. I address the errors and misconceptions associated with these exclusions at pages 28-29 and 61-64 of my rebuttal testimony.

[10] Tillman Direct at 10-11.

standard practice in regulatory proceedings is to consider the results of numerous approaches that are grounded in current capital market evidence when establishing a utility's ROE. Meanwhile, quarterly allowed ROEs reported by RRA are not necessarily representative or directly comparable to the utility at hand.[11] That is, there may be an "apples and oranges" issue when the RRA data is applied in the current rate setting environment.

Q16. WHAT OTHER BENCHMARKS INDICATE THAT THE ROE WITNESSES' RECOMMENDATIONS ARE TOO LOW TO BE CONSIDERED REASONABLE?

A16. Expected earned rates of return for other utilities provide yet another useful benchmark to gauge the reasonableness of the ROE Witnesses' recommendations. The expected earnings approach is predicated on the comparable earnings test, which developed as a direct result of the Supreme Court decisions in *Bluefield* and *Hope,* as I discuss in my Direct Testimony.[12] This test recognizes that investors compare the allowed ROE with returns available from other alternatives of comparable risk.

Importantly, the expected earnings approach explicitly recognizes that regulators do not set the returns that investors earn in the capital markets. Regulators can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital.

[11] For example, the lowest ROE granted over the last two-year period was 9.20% to Northern States Power Company ("NSP") in a Minnesota case decided May 11, 2017. This stipulated case resulted in a four-year multiyear rate plan spanning calendar years 2016 through 2019, a 2016 sales-forecast true-up which allowed it to collect nearly $59.99 million due to a one million megawatt-hour sales shortfall in 2016, and extension of full revenue decoupling for residential and small commercial customers through the end of the settlement period. These circumstances are not comparable to those faced by the Company in this proceeding.

[12] McKenzie Direct at 64-66.

This opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q17. HAS THE EXPECTED EARNINGS APPROACH BEEN RECOGNIZED AS A VALID ROE BENCHMARK?

A17. Yes. This method predominated before the DCF model became fashionable with academic experts, and it continues to be used around the country.[13] A textbook prepared for the Society of Utility and Regulatory Analysts labels the comparable earnings approach the "granddaddy of cost of equity methods" and points out that the amount of subjective judgment required to implement this method is "minimal," particularly when compared to the DCF and CAPM methods.[14] The *Practitioner's Guide* notes that the comparable earnings test method is "easily understood" and firmly anchored in the regulatory tradition of the *Bluefield* and *Hope* cases,[15] as well as sound regulatory economics. Similarly, *New Regulatory Finance* concluded that, "because the investment base for ratemaking purposes is expressed in book value terms, a rate of return on book value, as is the case with Comparable Earnings, is highly meaningful."[16]

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[13] For example, the Virginia State Corporation Commission is required by statute (Virginia Code § 56-585.1.A.2.a) to consider the earned returns on book value of electric utilities in its region. Similarly, FERC concluded that, "The returns on book equity that investors expect to receive from a group of companies with risks comparable to those of a particular utility are relevant to determining that utility's market cost of equity." Opinion No. 531-B, 150 FERC ¶ 61,165 at P 128 (2015). Another example is the Idaho Public Utilities Commission, which also references return on book equity evidence. *See, e.g.*, Order No. 29505, Case No. IC-E-03-13 at 38 (Idaho Public Utilities Commission, May 25, 2004).
[14] David C. Parcell, "The Cost of Capital – A Practitioner's Guide," (2010) at 115-116.
[15] *Id.*
[16] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 395.

Q18. DID MR. BAUDINO RECOGNIZE THE ECONOMIC PREMISE UNDERLYING THE EXPECTED EARNINGS APPROACH?

A18. Yes. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. As Mr. Baudino recognized, economists refer to the returns that an investor must forgo by not being invested in the next best alternative as "opportunity costs."[17] Mr. Baudino went on to explain that, "investor's opportunity cost is measured by what she or he could have invested in as the next best alternative."[18]

Q19. WHAT ROES ARE IMPLIED BY THE EXPECTED EARNINGS APPROACH FOR THE UTILITY PROXY GROUP?

A19. The year-end returns on common equity projected by Value Line over its forecast horizon for the firms in the utility proxy groups referenced by myself and the ROE Witnesses are shown on Exhibit No. 14. As shown there, once adjusted to mid-year, reference to the expected earnings approach implies an average cost of equity for my proxy group of utilities of 11.8%, while the expected annual average cost of equity for Dr. Woolridge's group and Mr. Baudino's group is 11.9%. These book return estimates are an "apples to apples" comparison to the 8.60% and 8.85% ROE recommendations of the ROE Witnesses.

Q20. PLEASE EXPLAIN THE RATIONALE FOR THE ADJUSTMENT TO CONVERT YEAR-END RETURNS TO AVERAGE RETURNS WHEN APPLYING THIS METHOD.

A20. The adjustment factor incorporated in my evaluation of expected returns is required because Value Line's reported returns are based on end-of-year book values. Since earnings are a flow over the year while book value is determined at

[17] Baudino Direct at 13.
[18] *Id.* at 14.

a given point in time, the measurement of earnings and book value are distinct concepts. It is this fundamental difference between a flow (earnings) and point estimate (book value) that makes it necessary to adjust to mid-year in calculating the ROE. Given that book value will increase or decrease over the year, using year-end book value (as Value Line does) understates or overstates the average investment that corresponds to the flow of earnings. To address this concern, earnings must be matched with a corresponding representative measure of book value, or the resulting ROE will be distorted.

The need for this adjustment has been recognized in the financial literature.[19] Similarly, FERC has also cited the necessity to adjust year-end data from Value Line to reflect average values when computing earned rates of return.[20] In its June 2014 decision establishing new policies regarding ROE and confirmed in its most recent opinion in September 2016, FERC relied directly on the expected earnings approach, which incorporates the exact same adjustment formula used in my Direct Testimony in this proceeding.[21] Similarly, the Virginia State Corporation Commission has determined that it is appropriate to rely on average book equity, rather than year-end equity, when evaluating earned rates of return.[22]

Q21. WHAT OTHER EVIDENCE INDICATES THAT THE RECOMMENDATIONS OF THE ROE WITNESSES FAIL TO MEET REGULATORY STANDARDS?

A21. As discussed in my Direct Testimony, required equity returns for firms in the competitive sector of the economy are also relevant in determining the

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[19] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 305-06.
[20] *Bangor Hydro-Elec. Co.*, 122 FERC ¶ 61,265 (2008).
[21] Opinion No. 531, 147 FERC ¶ 61,234 at P 146 (2014) and Opinion No. 551, 156 FERC ¶ 61,234 at P 239 (2016).
[22] *See, e.g., Case No. PUE-2014-00026,* Final Order at n. 84 (2014).

appropriate return to be allowed for rate-setting purposes.[23] The idea that investors evaluate utilities against the returns available from other investment alternatives – including the low-risk companies in my Non-Utility Group – is a fundamental cornerstone of modern financial theory. Aside from this theoretical underpinning, any casual observer of stock market commentary and the investment media quickly comes to the realization that investors' choices are almost limitless. It follows that utilities must offer a return that can compete with other risk-comparable alternatives, or capital will simply go elsewhere.

In fact, returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that the degree of risk, not the nature of the business, is relevant in evaluating an allowed ROE for a utility.[24] The cost of capital is based on the returns that investors could realize by putting their money in other alternatives, and the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment.

Q22. DID THE ROE WITNESSES PRESENT ANY OBJECTIVE EVIDENCE THAT WOULD SUPPORT A FINDING THAT YOUR NON-UTILITY PROXY GROUP IS RISKIER THAN THE COMPANIES IN HIS PROXY GROUP?

A22. No. Mr. Baudino, for instance, simply alluded to a general assertion that companies in the non-utility proxy group "face risks that a lower risk electric company like KPC does not face."[25] But my Direct Testimony did not contend that the specific operations or risk consideration of the companies in the Non-

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[23] McKenzie Direct at 73-77.
[24] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
[25] Baudino Direct at 43.

Utility Group are the same as those for utilities. Clearly, operating a worldwide enterprise in the beverage, pharmaceutical, retail, or food industry involves unique circumstances that are as distinct from one another as they are from an electric utility.

But as the Supreme Court recognized, investors consider the expected returns available from all these opportunities in evaluating where to commit their scarce capital. The simple observation that a firm operates in non-utility businesses says nothing at all about the overall investment risks perceived by investors, which is the very basis for a fair rate of return. So long as the risks associated with the Non-Utility Group are comparable to the Company and other utilities the resulting DCF estimates provide a meaningful benchmark for the cost of equity. As demonstrated in my Direct Testimony, a comparison of objective risk measures demonstrates conclusively that the Non-Utility Group is regarded as less risky than Kentucky Power, making it a conservative benchmark for a fair ROE in this case.[26]

Q23. DR. WOOLRIDGE SAYS THAT ONE REASON YOUR NON-UTILITY ANALYSIS IS FLAWED IS THAT SUCH COMPANIES "DO NOT OPERATE IN A HIGHLY REGULATED ENVIRONMENT."[27] DOES THE FACT THAT UTILITIES ARE REGULATED SOMEHOW INVALIDATE THIS COMPARISON OF OBJECTIVE RISK INDICATORS?

A23. Absolutely not. While I agree that utilities operate under a regulatory regime that differs from firms in the competitive sector, any risk-reducing benefit of regulation is already incorporated in the overall indicators of investment risk presented in Table 7 to my Direct Testimony. The impact of regulation on a

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[26] McKenzie Direct, Table 7, at 75.
[27] Woolridge Direct at 83.

utility's investment risks is one of the key elements considered by credit rating agencies and investment advisory services, such as Moody's, S&P Global ("S&P"), and Value Line, when establishing corporate credit ratings and other risk measures. As a result, the impact of regulatory protections is already reflected in my risk analysis. Meanwhile, the beta values supported by modern financial theory are premised on stock price volatility relative to the market as a whole, and are not dependent on an assessment of firm-specific considerations. As a result, the impact of regulatory differences on investment risk is accounted for in the published risk indicators relied on by investors and cited in my Direct Testimony.

Q24. WHAT WERE THE RESULTS OF YOUR ROE ANALYSIS FOR THE NON-UTILITY GROUP?

A24. As shown in Exhibit No. 11, page 3, the average ROEs for the Non-Utility group ranged from 10.4% to 10.8%. The midpoint of this range is 10.6%.

Q25. BASED ON YOUR COMPARISON OF THE ROE WITNESSES' RECOMMENDATIONS WITH ACCEPTED BENCHMARKS AND, IN LIGHT OF THE PROSPECT FOR HIGHER INTEREST RATES, WHAT DO YOU CONCLUDE?

A25. Based on these comparisons, the 8.60% and 8.85% ROE recommendations of Dr. Woolridge and Mr. Baudino, respectively, are below any reasonable outcomes. One fundamental standard underlying the regulation of public utilities, as set forth by the Supreme Court's *Bluefield* and *Hope* decisions, requires that the Company must have the opportunity to earn an ROE comparable to contemporaneous returns available from alternative investments of similar risk if it is to maintain its financial flexibility and ability to attract capital. The recommendations of the ROE Witnesses do not provide such an opportunity.

If the utility is unable to offer a return similar to the returns available from other opportunities of comparable risk, investors will become unwilling to supply capital to the utility on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their cost of capital. Both of these outcomes, which would be the result produced by the ROE Witnesses' recommendations, violate regulatory standards.

Q26. WHAT OTHER PITFALLS ARE ASSOCIATED WITH AN ROE THAT FALLS BELOW THOSE AUTHORIZED FOR OTHER COMPARABLE COMPANIES?

A26. Adopting an ROE for the Company that is well below the ROEs for comparable utilities could lead investors to view the Commission's regulatory framework as unsupportive, an outcome that would undermine investors' willingness to support future capital availability for investment in Kentucky. Security analysts study regulatory orders in order to advise investors where to invest their money. Moody's Investors Service ("Moody's) noted that, "[f]undamentally, the regulatory environment is the most important driver of our outlook."[28] Similarly, S&P concluded that "[t]he regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[29] Value Line summarizes these sentiments:

> As we often point out, the most important factor in any utility's success, whether it provides electricity, gas, or water, is the regulatory climate in which it operates. Harsh regulatory

[28] Moody's Investors Service, "Regulation Will Keep Cash Flow Stable As Major Tax Break Ends," *Industry Outlook* (Feb. 19, 2014).
[29] Standard & Poor's Corporation, "Key Credit Factors For The Regulated Utilities Industry," *RatingsDirect* (Nov. 19, 2013).

> conditions can make it nearly impossible for the best run utilities to earn a reasonable return on their investment.[30]

Utilities and their investors must lock up large sums of capital and are exposed to many risks over the long time horizon when they invest in utility infrastructure. At the levels proposed by the ROE Witnesses, the ability of Kentucky utilities to attract and retain capital would be compromised. This would have a long-term, chilling effect on investors' willingness to support capital investment in utility infrastructure, not just for the Company, but for all utilities in the state. On the other hand, if Commission actions instill confidence that the regulatory environment is supportive, investors will provide the necessary capital, which ultimately benefits customers and the service area economy.

II. RESPONSE TO DR. WOOLRIDGE

Q27. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR REBUTTAL TESTIMONY?

A27. My purpose here is to address Dr. Woolridge's mischaracterization of financial market conditions and the failings of his evaluation of a fair ROE for the Company.

A. Capital Market Conditions

Q28. WHAT ARE DR. WOOLRIDGE'S VIEWS REGARDING CURRENT CAPITAL MARKET CONDITIONS?

A28. Dr. Woolridge summarizes his review of current capital market conditions by concluding that "interest rates and capital costs are at low levels and are likely to remain low for some time."[31] He then adds, "[o]n this issue, I show that

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[30] Value Line Investment Survey, *Water Utility Industry*, January 13, 2017, p. 1780.
[31] Woolridge Direct at 5.

economists' forecasts of higher interest rates and capital costs, which are used by Mr. McKenzie, have been consistently wrong for a decade."[32]

Q29. HAVE RECENT DECISIONS BY THE FEDERAL RESERVE REINFORCED INVESTOR SENTIMENT THAT INTEREST RATES WILL TREND HIGHER?

A29. Yes. On June 14, 2017 the Federal Reserve increased the target range for the Federal Funds rate by another 25 basis points to 1.00% to 1.25%. This is in addition to similar increases in March 2017, December 2016, and December 2015. More rate hikes by the Federal Reserve are anticipated.

Q30. ARE INTEREST RATE FORECASTERS STILL PROJECTING HIGHER LONG-TERM RATES FOR COMPANIES LIKE KENTUCKY POWER?

A30. Yes. As illustrated in Figure R-2 above, investors continue to anticipate that interest rates will increase significantly from present levels.

Q31. DR. WOOLRIDGE SUGGESTS THAT INTEREST RATE FORECASTS SHOULD BE IGNORED BY THE COMMISSION BECAUSE FORECASTS HAVE BEEN WRONG IN THE PAST. DO YOU AGREE?

A31. Absolutely not. In estimating investors' required rate of return, what investors expect, not what actually happens, is what matters most. Any difference in actual rates as compared to analysts' forecasts is beside the point. What is most important is that investors share analysts' views when the forecasts were made and incorporate those views into their decision making process, not the actual rates that ultimately transpire.

Q32. DR. WOOLRIDGE DISCUSSES THE MARKET-TO-BOOK RATIO AND REACHES SEVERAL BOLD CONCLUSIONS IN THIS AREA. ARE HIS CONCLUSIONS REALISTIC?

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[32] *Id.*

A32. No. He says that a historical market-to-book ratio greater than one for the utility industry means that "for at least the last decade, returns on common equity have been greater than the cost of capital"[33] and "customers have been paying more than necessary to support an appropriate profit level for regulated utilities."[34]

Dr. Woolridge wants the Commission to sacrifice the Company's financial strength to favor a theoretical ideal of M/B equaling unity. The Commission does not purport to regulate utility stock market prices as Dr. Woolridge urges. Further, and as discussed below, there are many leaps between his economic theory and reality. But if the theory is correct, then Dr. Woolridge is asking the Commission to order an ROE that would almost certainly lead to a capital loss on shareholders' investment in the Company. From an economic perspective, such an action would violate the standards underlying a fair ROE.

Q33. IS THERE A CLEAR LINK BETWEEN M/B FOR UTILITIES AND ALLOWED RATES OF RETURN?

A33. No. Underlying Dr. Woolridge's conclusions is the supposition that regulators should set an ROE to produce a M/B of approximately 1.0. This is fallacious. For example, Regulatory Finance: Utilities Cost of Capital noted that:

> The stock price is set by the market, not by regulators. The market-to-book ratio is the end result of regulation, and not its starting point. The view that regulation should set an allowed rate of return so as to produce a market-to-book of 1.0, presumes that investors are irrational. They commit capital to a utility with a market-to-book in excess of 1.0, knowing full well that they will be inflicted a capital loss by regulators. This is certainly not a realistic or accurate view of regulation.[35]

With M/B for most utilities above 1.0, Dr. Woolridge is suggesting that, unless book value grows rapidly, regulators should establish equity returns that will

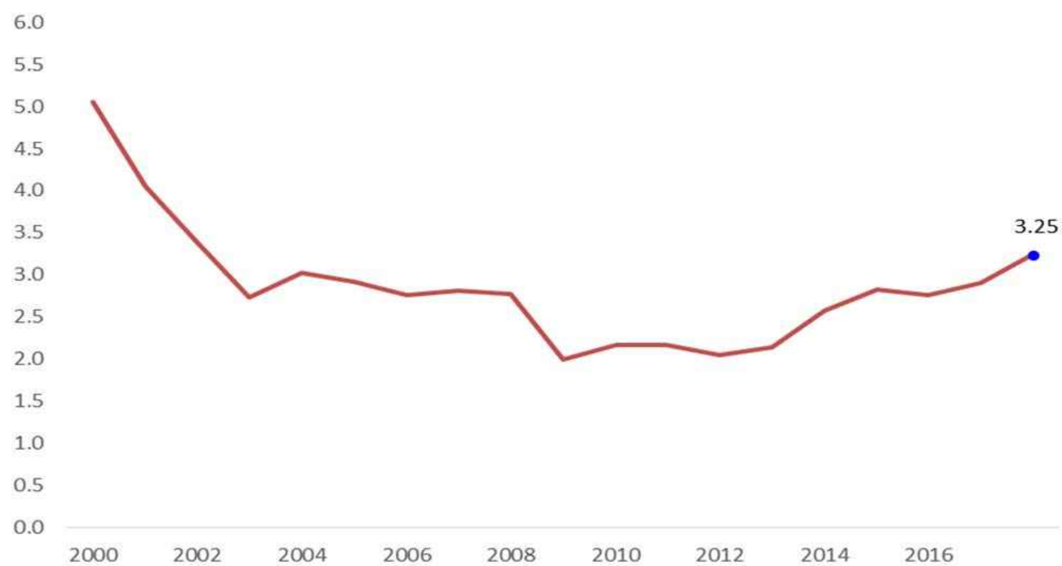
[33] *Id.* at 30.
[34] *Id.*
[35] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 376.

cause share prices to fall. Given the regulatory imperative of preserving a utility's ability to attract capital, this would be a truly nonsensical result. The M/B is determined by investors in the stock market, and a utility would be foreclosed from attracting capital if regulators were to push market-to-book to 1.0 while other firms command prices well in excess of 1.0 times book value.

Q34. IS THERE ANYTHING UNUSUAL ABOUT A STOCK PRICE EXCEEDING BOOK VALUE?

A34. No. In fact the majority of stocks currently sell substantially above book value. For example, Value Line reports that approximately 1,450 of the roughly 1,700 stocks it follows (including utilities and other industries) sell for prices in excess of book value.[36] In the figure below, I provide the average historical market price-to-book value ratios for the companies in the S&P 500 Composite Index.

FIGURE R-3
S&P 500 PRICE TO BOOK VALUE



Current S&P 500 Price To Book Value: 3.25
Mean: 2.76
Median: 2.74
Min: 1.78 (Mar. 2009)
Max: 5.06 (Mar. 2000)

36 www.valueline.com (retrieved Oct. 10, 2017).

Current Price To Book Ratio Is Estimated Based On Current Market Price And S&P 500 Book Value As Of March 2017, The Latest Reported By S&P.

Source: Standard & Poor's, www.multpl.com/s-p-500-price-to-book (retrieved Oct. 10, 2017).

For the 500 largest publicly-traded companies in the U.S. economy, stock market prices have averaged almost three times book value. The lowest value occurred at the market bottom in early 2009 during the "great recession," at 1.78 times.

The table below provides a listing of recent market-to-book ratios by industry.

TABLE R-1
MARKET-TO-BOOK RATIO BY SECTOR

Sector	Ratio
Financial	1.67
Energy	1.71
Utilities	1.89
Consumer Discretionary	2.69
Basic Materials	3.04
Conglomerates	3.41
Services	3.77
Healthcare	4.07
Transportation	4.76
Consumer Non-cyclical	5.05
Technology	5.07
Capital Goods	5.35
Retail	6.64

Source: https://csimarket.com/screening/index1.php?s=pb (retrieved Oct. 10, 2017).

The market-to-book ratio for the utilities sector of 1.89 is among the lowest of the industry groups, and it is well below the 2.76 times historical average for the S&P 500. The consistently higher market-to-book relationship for unregulated companies shows that Dr. Woolridge's theoretical 1.0 benchmark is misplaced and that his claims about excessive utility earnings based on this benchmark are incorrect.

Q35. ARE THERE OTHER IMPORTANT FACTORS BEYOND ROE THAT EXPLAIN M/B FOR UTILITIES ABOVE 1.0?

A35. Yes. Although Dr. Woolridge's comparison would make it appear that utility ROEs are the cause for M/B greater than one, this contention entirely ignores accounting issues and other considerations. Consider, for example, the merger and acquisition activity that has significantly affected utility stock market prices in recent years. Investors know that many acquisitions have occurred and that significant premiums and large capital gains have been associated with those transactions. While earnings expectations are a part of market pricing, Dr.

Woolridge's contention about direct causation between ROEs and market-to-book ratios is an extremely narrow view.

Q36. ARE ADJUSTMENTS BASED ON M/B A COMMON FEATURE IN DETERMINING ALLOWED ROES FOR UTILITIES?

A36. No. While arguments regarding the implications of a market-to-book greater than 1.0 are not uncommon, I am not aware of a single instance in recent history where a state regulator has approved a market-to-book adjustment in establishing a fair ROE. Meanwhile, FERC has explicitly recognized the fallacy of relying on market-to-book in evaluating cost of equity estimates. For example, the Presiding Judge in *Orange & Rockland* concluded, and the FERC affirmed that:

> The presumption that a market-to-book ratio greater than 1.0 will destroy the efficacy of the DCF formula disregards the realities of the market place principally because the market-to-book ratio is rarely equal to 1.0.[37]

The Initial Decision found that there was no support in FERC precedent for the use of market-to-book to adjust market derived cost of equity estimates based on the DCF model and concluded that such arguments were to be treated as "academic rhetoric" unworthy of consideration. Similarly, FERC rejected similar arguments from Dr. Woolridge more recently, concluding that "If, all else being equal, the regulator sets a utility's ROE so that the utility does not have the opportunity to earn a return on its book value comparable to the amount that investors expect that other utilities of comparable risk will earn on their book equity, the utility will not be able to provide investors the return they require to invest in that utility."[38]

Q37. IS DR. WOOLRIDGE'S M/B DISCUSSION RELEVANT TO THE SETTING OF THE COMPANY'S ROE IN THIS CASE?

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[37] *Orange & Rockland Utilities, Inc.*, Initial Decision, 40 FERC ¶ 63,053, 1987 WL 118,352 (F.E.R.C.).
[38] *Martha Coakely, et al.,* Opinion No. 531-B, 150 FERC ¶ 61,165 at P 129 (2015).

A37. No. Even in the unlikely event that the long trail of breadcrumbs between Dr. Woolridge's theoretical postulations on M/B and allowed returns remained unbroken, his conclusion is directed at the wrong hypothesis. The question before the Commission is not what ROE will produce a M/B of 1.0 for utilities; rather, the question is what ROE will allow Kentucky Power to maintain access to capital and grant stockholders the opportunity to earn a fair return on investment vis-à-vis alternatives of comparable risk.

B. Discounted Cash Flow Model

Q38. WHAT ARE THE FUNDAMENTAL PROBLEMS WITH THE DCF ANALYSES CONDUCTED BY DR. WOOLRIDGE (AT 33-48)?

A38. There are numerous problems with the DCF analyses presented by Dr. Woolridge that lead to biased end results:

- One of the proxy groups relied on by Dr. Woolridge is defective due to flaws in the screening criteria and data he used, causing the exclusion of comparable utilities.
- Reliance on dividend growth rates and historical growth measures do not reflect a meaningful guide to investors' expectations.
- Dr. Woolridge discounts reliance on analysts' earnings per share ("EPS") growth forecasts as somehow biased, and fails to sufficiently recognize that it is investors' *perceptions and expectations* that must be considered in applying the DCF model.
- Because Dr. Woolridge failed to test the reasonableness of model inputs, he incorrectly includes data that results in illogical cost of equity estimates.
- Dr. Woolridge's internal growth ("br") rates are downward biased because of computational errors and omissions.
- Rather than looking to the capital markets for guidance as to investors' forward-looking expectations, Dr. Woolridge applies the DCF model based on his own personal views.

As a result of these flaws and omissions, the resulting DCF cost of equity estimates are erroneously downward biased and fail to reflect investors' required rate of return.

Q39. DR. WOOLRIDGE APPLIED HIS ROE ANALYSES TO TWO GROUPS OF ELECTRIC UTILITIES, YOURS AND ONE BASED ON A DIFFERENT SET OF SELECTION CRITERIA. ARE THERE FLAWS IN HIS ELECTRIC PROXY GROUP?

A39. Yes. One of the selection criteria relied on by Dr. Woolridge required that at least 50% of the utility's revenues must come from regulated electric operations as reported by AUS Utility Report ("AUS").[39] There are several problems with this approach.

Q40. DO YOU AGREE WITH DR. WOOLRIDGE THAT THE NATURE OF A UTILITY'S REVENUES IS A VALID CRITERION IN SELECTING A PROXY GROUP FOR THE COMPANY?

A40. No. Dr. Woolridge failed to demonstrate how his subjective 50% revenue criterion translates into differences in the investment risks perceived by investors, while comparisons of objective indicators demonstrate that investment risks for the firms in my proxy groups are relatively homogeneous and comparable to the Company.

Q41. DID DR. WOOLRIDGE DEMONSTRATE ANY NEXUS BETWEEN A SUBJECTIVE CRITERION BASED ON REGULATED REVENUES AND OBJECTIVE MEASURES OF INVESTMENT RISK?

A41. No. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criterion in establishing a meaningful proxy group to estimate investors' required

[39] Woolridge Direct at 23. While Dr. Woolridge testimony references AUS, this report is no longer in publication, with the last monthly edition dated September 2016. It appears that Dr. Woolridge actually relied on information from the 2016 Form 10-K reports for the companies in his proxy groups. *See* "Electric_Utilities_-_Regulated_Revenue_-_2016_10-k.xlsx."

return is relative risk, not the source of the revenue stream or the nature of the asset base. Dr. Woolridge presented no evidence to demonstrate a connection between the subjective revenue criterion that he employed and the views of real-world investors in the capital markets. Nor did Dr. Woolridge provide any evidentiary support for his 50% threshold. Dr. Woolridge's testimony offers no explanation why a revenue cut-off of 50%, rather than, say, 40% or 60%, supposedly impacts a utility's operations sufficiently to justify its exclusion.

Moreover, due to differences in business segment definition and reporting between utilities, it is often impossible to accurately apportion financial measures, such as revenues and total assets, between regulated and non-regulated sources. As a result, even if one were to ignore the fact that there is no clear link between the nature of a utility's revenues or assets and investors' risk perceptions, it is generally not possible to accurately and consistently apply asset or revenue-based criteria. In fact, other regulators have rebuffed these notions, with FERC specifically rejecting arguments that utilities "should be excluded from the proxy group given the risk factors associated with its unregulated, non-utility business operations."[40]

Q42. CAN YOU ILLUSTRATE HOW A SCREEN BASED ON REVENUE COMPOSITION CAN LEAD TO AN ERRONEOUS CONCLUSION?

A42. Yes. Consider Public Service Enterprise Group, Sempra, and Vectren, which Dr. Woolridge omitted because regulated electric revenues were less than 50% of total revenue. However, after further inspection of their revenue composition, a different story is revealed. On page 1 of Exhibit JRW-4, Dr. Woolridge lists not only the level of regulated electric revenue, but also the level of regulated gas revenue. Gas distribution operations are regulated by the states in the same

[40] *Bangor Hydro-Elec. Co.*, 117 FERC ¶ 61,129 at PP 19, 26 (2006).

manner as electric operations, and there is no basis to distinguish between revenues from electric and gas utility operations. When gas revenues are combined with electric revenues, these companies all have regulated revenues that exceed the artificial, 50% threshold.[41]

Q43. DR. WOOLRIDGE ALSO EXCLUDED AVANGRID, ANOTHER COMPANY THAT IS IN YOUR GROUP. IS THERE A LOGICAL BASIS TO EXCLUDE AVANGRID?

A43. No. AVANGRID meets all of Dr. Woolridge's criteria: it is followed by Value Line, it has investment grade bond ratings, it has not cut or omitted any recent dividends, and long-term analyst growth forecasts are available.[42] Moreover, data from in AVANGRID's most recent SEC Form 10-K indicate that regulated operations contributed approximately 84% of total revenues.[43] For these reasons, AVANGRID should properly be included in the proxy group in this case.

Q44. DR. WOOLRIDGE NOTED THAT HE EXCLUDED EMERA INC. ("EMERA") AND FORTIS INC. ("FORTIS") FROM HIS PROXY GROUP BECAUSE THEY ARE BASED IN CANADA.[44] DOES THIS OBSERVATION SUPPORT HIS ELIMINATION OF THESE FIRMS?

A44. No. Other than his simple factual observation, Dr. Woolridge provided no evidence or explanation as to why investors would not regard Emera and Fortis to be comparable opportunities to the other utilities included in his proxy group. Like the other companies included by Dr. Woolridge, Emera is primarily engaged in electricity generation, transmission, and distribution; gas transmission and

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[41] From Exhibit JRW-4, page 1, the combined electric and gas revenue percentages are 78% for Sempra, 70% for Public Service Enterprise Group, and 56% for Vectren.
[42] While AVANGRID is not included in the AUS report cited in Dr. Woolridge's testimony, this is more likely to be a function of the cancellation of the publication and the resultant staleness of the data.
[43] AVANGRID reports regulated revenues of $5,030 million, out of total revenues of $6,018 million.
[44] Woolridge Direct at footnote 18.

distribution; and utility energy services, and serves approximately 2.4 million customers. As Value Line reported:

> With the addition of TECO's Florida and New Mexico operations, more than 75 percent of earnings are now generated from rate regulated businesses.[45]

Emera noted that, "With our Florida and New Mexico businesses integrated, more than 90 percent of Emera's earnings now come from our regulated businesses, surpassing our target of 75-85 percent," and that approximately 70% of future adjusted net income will be generated from its US subsidiaries.[46] Similarly, CRFA highlighted Emera's primary focus on electric utility operations, and classified Emera in its "Electric Utilities" industry group.[47] Thus, investors would regard Emera as a comparable investment alternative that is relevant to an evaluation of the required rate of return for Kentucky Power.

Similarly, like the other companies included in Dr. Woolridge's proxy group, Value Line observed that Fortis' "main focus is electricity, hydroelectric, and gas utility operations."[48] With $48 billion in assets, Fortis is one of the leading utility companies in North America, which include the Arizona operations of UNS Energy (including Tucson Electric Power), the New York operations of Central Hudson Gas & Electric, and ITC Holdings, which is the largest independent electricity transmission company in the U.S. There is no support for Dr. Woolridge's exclusion of Emera and Fortis simply because they are headquartered in Canada, and his position on this issue should be ignored.[49]

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[45] The Value Line Investment Survey (June 23, 2017) at 1218.
[46] Emera, Inc., 2016 Annual Report at 2, 19. In addition to its Florida and New Mexico utility operations, Emera also owns Bangor Hydro-Electric Company, which provides electric utility service in New England.
[47] CRFA, "Emera Incorporated," *Quantitative Stock Report* (June 24, 2017). CRFA, one of the world's largest providers of institutional-grade independent equity research, acquired the equity and fund research arm of S&P in October 2016.
[48] The Value Line Investment Survey (Sep. 15, 2017).
[49] Moreover, Dr. Woolridge is selective on the issue of involvement in foreign operations. His proxy group includes PPL Corporation, which serves 7.8 million electric customers in the United Kingdom.

Q45. DO YOU BELIEVE THAT HISTORICAL TRENDS IN DIVIDENDS PER SHARE ("DPS") PROVIDE A MEANINGFUL GUIDE TO INVESTORS' EXPECTATIONS?

A45. No. As discussed at length in my direct testimony, it is investors' future expectations – and not actual, historical results – that determine the current price they are willing to pay for commons stocks. If past trends in DPS are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for utilities, which have experienced declining dividend payouts, earnings pressure, and, in many cases, significant write-offs.

Dr. Woolridge noted the pitfalls associated with historical growth measures. As he correctly observed:

> [T]o best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.[50]

As he acknowledged, historical growth rates can differ significantly from the forward-looking growth rate required by the DCF model:

> However, one must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years), is unlikely to accurately measure investors' expectations due to the sensitivity of a single growth rate figure to fluctuations in individual firm performance as well as overall economic fluctuations (i.e., business cycles).[51]

While past conditions for utilities serve to depress historical DPS growth rates, they are not representative of long-term expectations for the electric utility industry. Moreover, to the extent historical trends for electric utilities are

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[50] Woolridge Direct at 40.
[51] *Id.*

meaningful, they are also captured in projected growth rates, such as those published by Value Line and Zacks Investment Research ("Zacks"), since securities analysts also routinely examine and assess the impact and continued relevance (if any) of historical trends. Similarly, the Regulatory Commission of Alaska ("RCA") has previously determined that analysts' EPS growth rates provide a superior basis on which to estimate investors' expectations:

> We also find persuasive the testimony . . . that projected EPS returns are more indicative of investor expectations of dividend growth than historical growth data because persons making the forecasts already consider the historical numbers in their analyses.[52]

The RCA has concluded that arguments against exclusive reliance on analysts' EPS growth rates to apply the DCF model "are not convincing."[53] This is consistent with the Commission's conclusions cited in my direct testimony, which noted that, "analysts' projections of growth will be relatively more compelling in forming investors' forward-looking expectations than relying on historical performance, especially given the current state of the economy."[54]

Q46. DR. WOOLRIDGE ARGUES (AT 39) THAT THE GROWTH RATE COMPONENT IN THE DCF MODEL REFLECTS "THE LONG-TERM DIVIDEND GROWTH RATE." DO YOU AGREE THAT THIS IS WHAT INVESTORS ARE MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A46. No. Again, implementation of the DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, growth rates in DPS are not likely to provide a meaningful guide to investors' current growth expectations.

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[52] Regulatory Commission of Alaska, U-07-76(8) at 65, n. 258.
[53] Regulatory Commission of Alaska, U-08-157(10) at 36.
[54] *Kentucky Utilities Co.*, Case No. 2009-00548 (Ky PSC Jul. 30, 2010) at 30-31.

Q47. WHAT ARE INVESTORS MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A47. As documented in my direct testimony, future trends in EPS, which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. The continued success of investment services such as IBES,[55] Value Line, and Zacks, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in EPS is far more influential than trends in DPS. As explained in *New Regulatory Finance*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth].[56]

The availability of projected EPS growth rates also is key to investors relying upon this measure as compared to future trends in DPS. Apart from Value Line, investment advisory services do not generally publish comprehensive DPS growth projections, and this scarcity of dividend growth rates relative to the abundance of EPS forecasts attests to their relative influence. The fact that analyst EPS growth estimates are routinely referenced in the financial media and

[55] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters.
[56] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 298.

in investment advisory publications implies that investors use them as a primary basis for their expectations. As observed in *New Regulatory Finance*:

> The sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. The fact that these investment information providers focus on growth in earnings rather than growth in dividends indicates that the investment community regards earnings growth as a superior indicator of future long-term growth. Surveys of analytical techniques actually used by analysts reveal the dominance of earnings and conclude that earnings are considered far more important than dividends.[57]

While I did not rely solely on EPS projections in applying the DCF model,[58] my evaluation clearly supports greater reliance on EPS growth rate projections than other alternatives. Similarly, my Direct Testimony documented the Commission's preference for relying on analysts' growth forecasts, which is supported by the findings of other regulatory agencies.[59]

Q48. IS DR. WOOLRIDGE CONSISTENT IN HIS INSISTENCE THAT HISTORICAL GROWTH RATES AND TRENDS IN DPS MUST BE CONSIDERED IN APPLYING THE DCF MODEL?

A48. No. In testimony before FERC, Dr. Woolridge has applied the DCF model without any reference to historical trends or growth rates in DPS.[60] In the present case, despite his indictment of analysts' EPS growth projections, this data largely serves as the basis for his own DCF analysis. When selecting the final growth rates for both proxy groups referenced in his testimony, Dr. Woolridge gives "primary weight" to the projected EPS growth rates of Wall Street analysts.[61] So, while Dr. Woolridge complains vociferously about the suitability of analysts' EPS

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[57] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 302-303.
[58] As discussed in my direct testimony, I also examined the "br+sv", sustainable growth rates for the companies in my proxy groups.
[59] McKenzie Direct at 38.
[60] *See, e.g.*, *Testimony of J. Randall Woolridge*, Docket No. EL11-66-000, Exhibit SC-100.
[61] Woolridge Direct at 46.

growth projections, he relies primarily on these same projections in reaching his ultimate DCF conclusions. His criticisms of the use of analysts' EPS growth projections ring hollow and are without merit in this light.

Q49. DOES MR. BAUDINO ACKNOWLEDGE THE SUPERIORITY OF FORECASTED DATA, AS OPPOSED TO HISTORICAL DATA, IN THE DCF PROCESS?

A49. Yes. Mr. Baudino concurs that analysts' forecasts are superior:

> Return on equity analysis is a forward-looking process. Five-year or ten-year historical growth rates may not accurately represent investor expectations for dividend growth. Analysts' forecasts for earnings and dividend growth provide better proxies for the expected growth component in the DCF model than historical growth rates. Analysts' forecasts are also widely available to investors and one can reasonably assume that they influence investor expectations.[62]

Q50. IS THE DOWNWARD BIAS IN DR. WOOLRIDGE'S HISTORICAL GROWTH MEASURES SELF EVIDENT?

A50. Yes, it is. As shown on page 3 of Exhibit JRW-10, thirty three of the historical growth rates reported by Dr. Woolridge for his electric proxy companies were 2.0% or less, including sixteen negative values.[63] A negative growth rate implies a cost of equity that falls below the utility's dividend yield which makes no economic sense, since investors could earn higher returns on less-risky utility bonds. These outcomes illustrate the fact that Dr. Woolridge's historical growth measures provide no meaningful information regarding the expectations and requirements of investors.

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[62] Baudino Direct at 21.

[63] For the McKenzie Proxy Group shown on page 3 of Exhibit JRW-10, fourteen of the historical growth rates reported by Dr. Woolridge were 2.0% or less, including seven negative values.

Q51. DID DR. WOOLRIDGE ALSO INCLUDE LOW AND NEGATIVE GROWTH RATES IN HIS EXAMINATION OF PROJECTED GROWTH RATES?

A51. Yes, as shown on page 4 of Exhibit JRW-10, he included five growth rates at 1.5% or less in his analysis of Value Line projected growth rates for his electric proxy group.[64] Because these growth rates imply cost of equity estimates that are not materially higher than the yields on less risky utility bonds, they are not meaningful and should be excluded from his DCF analysis. On page 5 of Exhibit JRW-10, Dr. Woolridge includes two companies (Entergy Corporation and FirstEnergy Corporation) that have negative analyst projected growth rate estimates.

Q52. DID DR. WOOLRIDGE MAKE ANY EFFORT TO TEST THE REASONABLENESS OF THE INDIVIDUAL GROWTH ESTIMATES HE RELIED ON TO APPLY THE CONSTANT GROWTH DCF MODEL?

A52. No. Despite recognizing that caution is warranted in using historical growth rates, Dr. Woolridge simply calculated the average and median of the individual growth rates with no consideration for the reasonableness of the underlying data. In fact, as indicated above, many of the cost of equity estimates implied by Dr. Woolridge's DCF application are illogical, given the risk-return tradeoff that is fundamental to finance. The table below highlights some of the individual company results that are incorporated into Dr. Woolridge's DCF analysis.

[64] For the McKenzie Proxy Group shown on page 4 of Exhibit JRW-10, two of the projected growth rates reported by Dr. Woolridge were 1.5% or less.

TABLE R-2
SAMPLE WOOLRIDGE COST OF EQUITY ESTIMATES

Company	Dividend Yield	Growth	DCF ROE
Entergy Corp.	4.5%	-4.3%	0.2%
First Energy Corp.	4.7%	-2.9%	1.8%
MGE Energy, Inc.	2.0%	4.0%	6.0%
PPL Corporation	4.1%	2.5%	6.5%

Source: Exhibit JRW-10, pages 2 (90 Day Dividend Yield) and 5 (Mean Growth). DCF ROE is sum of dividend yield and growth.

With current triple-B utility interest rates in the 4.4% range, the above results are not reasonable ROE outcomes. And as indicated in my direct testimony[65] and illustrated in Figure R-2 above, it is generally expected that long-term interest rates will rise as the Federal Reserve normalizes its monetary policies. As shown in the table below, the increase in debt yields anticipated by IHS Global Insight and the Energy Information Administration imply an average triple-B bond yield of approximately 6.22% over the period 2018-2022.

[65] McKenzie Direct at 16-23.

TABLE R-3
BOND YIELD FORECAST

	Baa Yield 2018-22
Projected Aa Utility Yield	
IHS Global Insight (a)	5.79%
EIA (b)	5.56%
Average	5.67%
Current Baa - Aa Yield Spread (c)	0.55%
Implied Baa Utility Yield	**6.22%**

(a) IHS Global Insight (Aug. 24, 2017).
(b) Energy Information Administration, Annual Energy Outlook 2017 (Jan. 5, 2017)
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period Apr. - Sep. 2017.

Equity returns close to, or less than, this threshold are not credible. Yet, Dr. Woolridge factors them into his final conclusions, which biases his results downward.

Q53. WHAT APPROACH SHOULD DR. WOOLRIDGE HAVE USED TO EVALUATE LOW-END DCF ESTIMATES?

A53. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for their risk bearing. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, Dr. Woolridge should have evaluated his DCF results to eliminate estimates that are determined to be illogical when compared against the yields available to investors from less risky utility bonds. The practice of eliminating low-end outliers has been affirmed in numerous FERC proceedings. In Opinion

No. 531, FERC concluded that, "The purpose of the low-end outlier test is to exclude from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt."[66] FERC has used 100 basis points above the six-month average public utility bond yield as an approximation of this threshold, but has also recognized that this is a flexible test.[67]

Q54. DR. WOOLRIDGE ARGUES YOUR ANALYSIS IS FLAWED BECAUSE OF YOUR "ASYMMETRICAL ELIMINATION OF DCF RESULTS."[68] IS THIS A VALID ARGUMENT?

A54. No. As discussed above, low-end outliers were evaluated against the observable returns available from long-term bonds. But the fact that there are numerous results that fail this test of reasonableness says nothing about the validity of estimates at the upper end of the range of results, and there is no basis to discard an equal number of values from the top of the range. While the upper end cost of equity estimate of 14.0% from my Exhibit No. 5 may exceed expectations for most utilities, the remaining low-end estimates in the 7.0% range are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the DCF estimates, these values provides a reasonable basis on which to evaluate investors' required rate of return.

Q55. DR. WOOLRIDGE RELIED ON SUSTAINABLE, "BR" GROWTH RATES (EXHIBIT JRW-10, P. 4). SHOULD THE COMMISSION PLACE ANY WEIGHT ON THESE VALUES?

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[66] Opinion No. 531 at P 122.
[67] *Id.*
[68] Woolridge Direct at 65.

A55. No. Dr. Woolridge's internal growth rates are downward biased because of computational errors (use of year-end book value) and omissions (failure to incorporate the impact of issuing new shares). Dr. Woolridge based his calculations of the internal, "br" retention growth rate on data from Value Line. If the rate of return, or "r" component of the internal growth rate, is based on end-of-year book values, such as those reported by Value Line, it will understate actual returns because of growth in common equity over the year.

Q56. WHAT OTHER CONSIDERATION LEADS TO A DOWNWARD BIAS IN DR. WOOLRIDGE'S CALCULATION OF INTERNAL, "BR" GROWTH?

A56. Dr. Woolridge ignored the impact of additional issuances of common stock in his analysis of the sustainable growth rate. Under DCF theory, the "sv" factor is a component designed to capture the impact on growth of issuing new common stock at a price above, or below, book value. As noted by Myron J. Gordon in his 1974 study:

> When a new issue is sold at a price per share P = E, the equity of the new shareholders in the firm is equal to the funds they contribute, and the equity of the existing shareholders is not changed. However, if P > E, part of the funds raised accrues to the existing shareholders. Specifically…[v] is the fraction of the funds raised by the sale of stock that increases the book value of the existing shareholders' common equity. Also, "v" is the fraction of earnings and dividends generated by the new funds that accrues to the existing shareholders.[69]

In other words, the "sv" factor recognizes that when new stock is sold at a price above (below) book value, existing shareholders experience equity accretion (dilution). In the case of equity accretion, the increment of proceeds above book value (P > E in Professor Gordon's example) leads to higher growth because it increases the book value of the existing shareholders' equity. In short, the "sv" component is entirely consistent with DCF theory, and the fact that Dr. Woolridge

[69] Myron J. Gordon, "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* (1974) at 31-32.

failed to consider the incremental impact on growth results in another downward bias to his "internal" growth rates, which should be given no weight.[70]

Q57. DOES DR. WOOLRIDGE'S REFERENCE TO THE MEDIAN (AT 44-45) CORRECT FOR ANY UNDERLYING BIAS IN HIS HISTORICAL GROWTH RATES?

A57. No. The median is simply the observation with an equal number of data values above and below. For odd-numbered samples, the median relies on only a single number, *e.g.*, the fifth number in a nine-number set. Reliance on the median value for a series of illogical values does not correct for the inability of individual cost of equity estimates to pass fundamental tests of economic logic.

Q58. WHAT DO YOU CONCLUDE BASED ON YOUR REVIEW OF DR. WOOLRIDGE'S DCF ANALYSES?

A58. Even a cursory review of pages 3-5 of Exhibit JRW-10 suggests that Dr. Woolridge could basically have arrived at any DCF growth rate that he wanted. These pages are a mishmash of historical and projected growth rates over varying time periods and not just for earnings, but for dividends and book value as well. There are literally hundreds of growth rates to choose from. The averages/medians for the two proxy groups referenced in his analysis range from 3.6% to 6.0%, and almost any DCF result could have been interpreted based on this data. For this reason, his DCF-based ROE recommendations are suspect and should be weighted accordingly.

Furthermore, trends in DPS are impacted by changes in industry financial policies and Dr. Woolridge failed to evaluate the underlying reasonableness of individual growth rates. Finally, the calculations used to arrive at Dr.

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[70] In prior testimony before FERC, Dr. Woolridge incorporated an adjustment to correct for the downward bias attributable to end-of-year book values, and recognized the additional growth from new share issues by incorporating the "sv" component. *See, e.g., Testimony of J. Randall Woolridge*, FERC Docket No. EL-66 at Exhibit JRW-8, pp. 3-4 (2011).

Woolridge's internal growth rates are flawed and incomplete because he did not adjust his end-of-year book values for growth in common equity over the year and because he completely left out the "sv" factor designed to capture the impact on growth of issuing new common stock. As a result, his DCF cost of equity estimates are biased downward and fail to reflect investors' required rate of return.

C. Capital Asset Pricing Model

Q59. WHAT IS THE FUNDAMENTAL PROBLEM ASSOCIATED WITH THE APPROACH THAT DR. WOOLRIDGE USED TO APPLY THE CAPM?

A59. The CAPM application presented by Dr. Woolridge was based entirely on *historical* rates of return, not current projections. Like the DCF model, risk premium methods – including the CAPM – are *ex-ante,* or forward-looking models based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM approach must be applied using data that reflects the expectations of actual investors in the market. The primacy of current expectations was recognized by Morningstar, one of the sources relied on by Dr. Woolridge to apply the CAPM:

> The cost of capital is always an expectational or forward-looking concept. While the past performance of an investment and other historical information can be good guides and are often used to estimate the required rate of return on capital, the expectations of future events are the only factors that actually determine cost of capital.[71]

By failing to look directly at the returns investors are currently requiring in the capital markets, as I did on Exhibit Nos. 7 and 8 to my direct testimony, the 7.6%

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[71] Morningstar, *Ibbotson SBBI, 2013 Valuation Yearbook* at 21.

historical CAPM estimate developed by Dr. Woolridge[72] falls woefully short of investors' current required rate of return.

Q60. DR. WOOLRIDGE (AT 52) CHARACTERIZES HIS RISK PREMIUM AS *EX ANTE*. IS THIS AN ACCURATE ASSESSMENT?

A60. No. In order to be considered a forward-looking, *ex ante* estimate of the current market risk premium, the analysis must be predicated on investors' current expectations. Dr. Woolridge did not attempt to develop a market risk premium using current capital market information. Rather, he simply presented the results of various studies and surveys conducted in the past. Certain of these studies may have attempted to infer the equity risk premium using expected data at the time they were developed, but expectations at some point in the past are not equivalent to investors *ex ante* requirements in capital markets today.

Q61. IS THERE GOOD REASON TO ENTIRELY DISREGARD THE RESULTS OF HISTORICAL CAPM ANALYSES SUCH AS THOSE PRESENTED BY DR. WOOLRIDGE?

A61. Yes. Applying the CAPM is complicated by the impact of the Federal Reserve policies on investors' risk perceptions and required returns. As the Staff of the Florida Public Service Commission concluded regarding historical applications of the CAPM:

> [R]ecognizing the impact the Federal Government's unprecedented intervention in the capital markets has had on the yields on long-term Treasury bonds, staff believes models that relate the investor-required return on equity to the yield on government securities, such as the CAPM approach, produce less reliable estimates of the ROE at this time.[73]

[72] Woolridge Direct at 57.
[73] *Staff Recommendation for Docket No. 080677-E1 - Petition for increase in rates by Florida Power & Light Company*, Docket No. 080677-E1, at 280 (Dec. 23, 2009).

Similarly, in *Orange & Rockland Utilities*, FERC determined that CAPM methodologies based on historical data were suspect because whatever historical relationships existed between debt and equity securities may no longer hold.[74] FERC concluded that historical risk premiums are downward biased given recent trends of low yields for Treasury bonds.[75]

As a result, there is every indication that the historical CAPM approach fails to fully reflect the risk perceptions of real-world investors in today's capital markets, which would violate the standards underlying a fair rate of return by failing to provide an opportunity to earn a return commensurate with other investments of comparable risk.

Q62. DID DR. WOOLRIDGE ALSO RECOGNIZE THE FRAILTIES OF HIS HISTORICAL CAPM APPROACHES?

A62. Yes. Dr. Woolridge noted that *ex-post*, historical rates of return "are not the same as *ex ante* expectations," and observed that, "The use of historical returns as market expectations has been criticized in numerous academic studies."[76] Dr. Woolridge admitted that "risk premiums can change over time … such that *ex post* historical returns are poor estimates of *ex ante* expectations."[77] Finally, Dr. Woolridge conceded, that his historical CAPM approach provides "a less reliable indication of equity cost rates for public utilities."[78]

Q63. IS THERE EVIDENCE THAT THE STUDIES REFERENCED BY DR. WOOLRIDGE DO NOT REFLECT INVESTORS' EXPECTATIONS?

A63. Yes. The vast majority of the equity risk premium findings reported by Dr. Woolridge do not make economic sense and contradict his own testimony. For

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[74] *See Orange & Rockland Utils., Inc.*, 40 FERC ¶ 63,053 at 65,208-09 (1987), *aff'd*, Opinion No. 314, 44 FERC ¶ 61,253 at 65,208 (2008).
[75] *See New York Independent System Operator, Inc.*, 146 FERC ¶ 61,043 at P 105 (2014).
[76] Woolridge Direct at 52-53.
[77] *Id.*
[78] *Id.* at 33.

example, page 5 of Dr. Woolridge's Exhibit JRW-11 reveals that well over half of the historical studies included in Dr. Woolridge's review found market equity risk premiums of approximately 5.0% or below. This was also true for nearly half of the individual risk premium studies that Dr. Woolridge classified as "more recent."[79] But combining a market equity risk premium of 5.0% with Dr. Woolridge's 4.0% risk-free rate results in an indicated cost of equity for the <u>market as a whole</u> of 9.0%, which barely exceeds his ROE recommendation for Kentucky Power in this case.

Meanwhile, after noting that beta is the only relevant measure of investment risk under modern capital market theory, Dr. Woolridge concluded that his comparison of beta values (Exhibit JRW-8) indicates that investors' required return on the market as a whole should exceed the cost of equity for electric utilities.[80] Based on Dr. Woolridge's own logic, it follows that a market rate of return that does not significantly exceed his own downward biased ROE recommendation has no relation to the current expectations of real-world investors. The fact that much of his CAPM "evidence" violates the risk-return tradeoff that is fundamental to financial theory clearly illustrates the frailty of Dr. Woolridge's analyses.

Q64. ARE THERE OTHER SHORTCOMINGS ASSOCIATED WITH THE SOURCES CITED BY DR. WOOLRIDGE?

A64. Yes. For example, the *Fernandez* survey is the result of a mass solicitation to more than 23,000 email addresses, out of which approximately 6,900 responses were received.[81] While many of the responses were undoubtedly from informed

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[79] Exhibit JRW-11, p. 6.
[80] Woolridge Direct at 31-32.
[81] Pablo Fernandez, Alberto Ortiz, and Isabela Fernandez Acin, "Market Risk Premium used in 71 Countries in 2016: a survey with 6,923 answers," (May 2016) https://papers.ssrn.com/sol3/Delivery.cfm/SSRN_ID2776636_code12696.pdf?abstractid=2776636&mirid=1&type=2 (last visited Oct. 11, 2017).

professionals, there is no ability verify the experience or familiarity of the respondents with the subject matter. In addition, the wording of the surveys is imprecise and open to interpretation. For example, the 2016 survey simply asks, "The Market Risk Premium that I am using in 2016 for USA is _____%,"[82] which is entirely unclear. The respondent has no idea whether he or she is being queried for a risk premium during 2016, or over some other time period; nor is the basis on which the risk premium is calculated even specified.[83]

Meanwhile, the approach used to derive a market risk premium in *Damodaran* forces the growth rate for all competitive firms to a constant long-term rate after five years. In addition, *Damodaran* inexplicably assumes that this long term rate of growth will equal the current yield on U.S. Treasury bonds, or 2.12% in its current rendition.[84] This is significantly below even the GDP growth rate range of 3.0% to 5.0% advocated by Dr. Woolridge.[85] There is no logical link between investors' long-term growth expectations for common stocks and the current Treasury bond yield, and I know of no credible source of investment guidance that is expecting growth for all companies in the economy to collapse to 2.12% over the next five years.

The fundamental problem with Dr. Woolridge's approach is that instead of looking directly at an equity risk premium based on current expectations – which is what is required in order to properly apply the CAPM and is the approach I took – he undertakes an unrelated exercise of compiling selected computations culled from the historical record. In short, while there are many potential definitions of the equity risk premium, the only relevant issue for application of

[82] *Id.*
[83] One respondent to the *Fernandez* survey characterized the imprecision and ambiguity this way: "You don't define exactly what you mean by "Market Risk Premium". Different authorities define it in different ways. Is it expected return over short-term government securities (*e.g.*, 30 or 90 day T-Bills), or longer-term government bonds?" *Id.*
[84] http://www.stern.nyu.edu/~adamodar/pc/implprem/ERPSept17.xls (last visited Oct. 11, 2017).
[85] Woolridge Direct at 72.

the CAPM in a regulatory context is the return investors currently expect to earn on money invested today in the risky market portfolio versus the risk-free U.S. Treasury alternative.

Q65. WAS DR. WOOLRIDGE (EXHIBIT JRW-11, PP. 5-6) JUSTIFIED IN RELYING ON GEOMETRIC MEANS AS A MEASURE OF AVERAGE RATE OF RETURN WHEN APPLYING THE HISTORICAL CAPM?

A65. No. While both the arithmetic and geometric means are legitimate measures of average return, they provide different information. Each may be used correctly, or misused, depending upon the inferences being drawn from the numbers. The geometric mean of a series of returns measures the constant rate of return that would yield the same change in the value of an investment over time. The arithmetic mean measures what the expected return would have to be each period to achieve the realized change in value over time.

In estimating the cost of equity, the goal is to replicate what investors expect going forward, not to measure the average performance of an investment over an assumed holding period. When referencing realized rates of return in the past, investors consider the equity risk premiums in each year independently, with the arithmetic average of these annual results providing the best estimate of what investors might expect in future periods. *New Regulatory Finance* had this to say:

> The best estimate of expected returns over a given future holding period is the arithmetic average. *Only arithmetic means are correct for forecasting purposes and for estimating the cost of capital.* There is no theoretical or empirical justification for the use of geometric mean rates of returns as a measure of the appropriate discount rate in computing the cost of capital or in computing present values.[86]

Similarly, Morningstar concluded that:

[86] Roger A. Morin, "New Regulatory Finance" *Public Utilities Reports, Inc.* (2006) at 116-117, (emphasis added).

> For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. … The geometric average is more appropriate for reporting past performance, since it represents the compound average return.[87]

Q66. WHAT DOES THIS IMPLY WITH RESPECT TO DR. WOOLRIDGE'S CAPM ANALYSES?

A66. For a variable series, such as stock returns, the geometric average will <u>always</u> be less than the arithmetic average. Accordingly, Dr. Woolridge's reference to geometric average rates of return provides yet another element of built-in downward bias.

Q67. DR. WOOLRIDGE REFERENCES CAPITAL MARKET TRENDS.[88] IS IT APPROPRIATE TO CONSIDER ANTICIPATED CAPITAL MARKET CHANGES IN APPLYING THE CAPM?

A67. Yes. As discussed in my direct testimony, there is widespread consensus that interest rates will increase materially as the economy strengthens. Accordingly, in addition to the use of current bond yields, I also applied the CAPM and ECAPM approaches based on the forecasted long-term Treasury bond yields developed based on projections published by Value Line, IHS Global Insight and Blue Chip.

D. Other ROE Issues

Q68. PLEASE RESPOND TO DR. WOOLRIDGE'S ARGUMENT THAT THERE IS NO BASIS TO INCLUDE A FLOTATION COST ADJUSTMENT.

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[87] Morningstar, *Ibbotson SBBI 2013 Valuation Yearbook* at 56.

[88] Dr. Woolridge cites "the possibility of higher interest rates" as one factor that he considered in selecting the risk-free rate used in his application of the CAPM. Woolridge Direct at 50.

A68. The need for a flotation cost adjustment to compensate for past equity issues is recognized in the financial literature. In a *Public Utilities Fortnightly* article, for example, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings.[89] Similarly, *Regulatory Finance: Utilities' Cost of Capital* contains the following discussion:

> Another controversy is whether the underpricing allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. … The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[90]

Q69. IS THERE ANY MERIT TO DR. WOOLRIDGE'S ARGUMENT (AT 80) THAT FLOTATION COSTS CAN BE IGNORED BECAUSE THEY CANNOT BE PRECISELY QUANTIFIED?

A69. No. As discussed in my direct testimony,[91] the costs incurred to issue new debt securities are recorded on the financial books of the utility and routinely recovered from customers without controversy. While equity flotation costs are every bit as necessary to supply invested capital, they are not recorded on the utility's books, so there is no precise accounting for these costs. Nevertheless,

[89] E.F. Brigham, D.A. Aberwald, and L.C. Gapenski, "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly*, May, 2, 1985.
[90] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 335.
[91] McKenzie Direct at 67.

they represent necessary and legitimate expenses incurred to obtain the equity capital invested in utility plant, and unless some provision is made for their recovery, investors will not be offered an opportunity to fully earn their required ROE. The need to consider flotation costs has been documented in the financial literature and Dr. Woolridge's observations provide no basis to ignore issuance costs.

Q70. PLEASE RESPOND TO DR. WOOLRIDGE'S SPECIFIC CRITICISMS OF YOUR FLOTATION COST ADJUSTMENT (AT 80-82).

A70. Flotation cost adjustments are supported by recognized regulatory textbooks and based on research reported in the academic literature, and the lack of a precise accounting of past issuance expenses necessary to raise the common equity capital invested in Kentucky Power provides no basis to ignore a flotation cost adjustment.

Meanwhile, Dr. Woolridge mistakenly claims that a flotation cost adjustment "is necessary to prevent the dilution of the existing shareholders."[92] In fact, a flotation cost adjustment is required in order to allow the utility the opportunity to recover the issuance costs associated with selling common stock. Dr. Woolridge's observation about the level of market-to-book ratios (at 80) may be factually correct, but it has nothing to do with flotation costs. The fact that market prices may be above book value does not alter 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. Even if the utility is not expected to issue additional common stock, a flotation cost adjustment is necessary to compensate for flotation costs incurred in connection with <u>past</u> issues of common stock.

[92] Woolridge Direct at 80.

Dr. Woolridge's argument (at 81) that flotation costs are not "out-of-pocket expenses" is simply wrong. Dr. Woolridge apparently believes that if investors in past common stock issues had paid the full issuance price directly to the utility and the utility had then paid underwriters' fees by issuing a check to its investment bankers, that flotation cost would be a legitimate expense. Dr. Woolridge's observation merely highlights the absence of an accounting convention to properly accumulate and recover these legitimate and necessary costs.

Q71. HAVE OTHER REGULATORS RECOGNIZED THAT FLOTATION COSTS ARE A LEGITIMATE CONSIDERATION IN ESTABLISHING A FAIR ROE?

A71. Yes. For example, in Docket No. UE-991606 the Washington Utilities and Transportation Commission concluded that a flotation cost adjustment of 25 basis points should be included in the allowed return on equity:

> The Commission also agrees with both Dr. Avera and Dr. Lurito that a 25 basis point markup for flotation costs should be made. This amount compensates the Company for costs incurred from past issues of common stock. Flotation costs incurred in connection with a sale of common stock are not included in a utility's rate base because the portion of gross proceeds that is used to pay these costs is not available to invest in plant and equipment.[93]

Similarly, the South Dakota Public Utilities Commission has recognized the impact of issuance costs, concluding that, "recovery of reasonable flotation costs is appropriate."[94] Another example of a regulator that approves common stock issuance costs is the Mississippi Public Service Commission, which routinely includes a flotation cost adjustment in its Rate Stabilization Adjustment Rider

[93] *Third Supplemental Order*, WUTC Docket No. UE-991606, et al., p. 95 (September 2000).
[94] *Northern States Power Co*, EL11-019, Final Decision and Order at P 22 (2012).

formula.[95] The Public Utilities Regulatory Authority of Connecticut[96] and the Minnesota Public Utilities Commission[97] have also recognized that flotation costs are a legitimate expense worthy of consideration in setting a fair ROE.

Q72. IS THERE ANY MERIT TO DR. WOOLRIDGE'S ARGUMENT (AT 75-77) THAT THE SIZE PREMIUM DOES NOT APPLY TO UTILITY COMMON STOCKS?

A72. No. There is no credible basis to conclude that utilities are immune from the well-documented relationship between smaller size and higher realized rates of return. For example, Dr. Woolridge places significant weight on a 1993 study by Annie Wong,[98] but a closer examination of this research reveals that it is largely inconclusive, and inconsistent with the CAPM. In fact, her results demonstrate no material difference between utilities and industrial firms with respect to size premiums, and her study finds no significant relationship between beta and returns, which contradicts modern portfolio theory and the CAPM. A more recent study published in the Quarterly Review of Economics and Finance reconsiders Wong's evidence and concludes that "new information . . . indicates there is a small firm effect in the utility sector."[99]

Q73. DR. WOOLRIDGE CRITICIZES THE MARKET RETURN THAT YOU USE IN YOUR CAPM AND ECAPM ANALYSES CLAIMING THAT "AS INDICATED IN RECENT RESEARCH, THE LONG-TERM EARNINGS GROWTH RATES OF COMPANIES ARE LIMITED TO THE GROWTH RATE IN GDP" (AT 73). WHAT IS YOUR RESPONSE TO THIS CLAIM?

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[95] *See, e.g.*, Entergy Mississippi, Inc., Formula Rate Plan Rider (Apr. 15, 2015), http://www.entergy-mississippi.com/content/price/tariffs/emi_frp.pdf (last visited Mar. 16, 2017).
[96] *See, e.g.*, Docket No. 14-05-06, Decision (Dec. 17, 2014) at 133-134.
[97] *See, e.g.*, Docket No. E001/GR-10-276, Findings of Fact, Conclusions, and Order at 9.
[98] Woolridge Direct at 75-76.
[99] Thomas M. Zepp, "Utility stocks and the size effect—revisited," Quarterly Review of Economics and Finance, 43 (2003) 578-582.

A73. The use of long-term GDP growth as an upper bound to the DCF growth rate is not justified. There are several reasons why GDP growth is not relevant in applying the DCF model:

- Practical application of the DCF model does not require a long-term growth estimate over a horizon of 25 years and beyond – it requires a growth estimate that matches investors' expectations.
- My evidence supports the conclusion that investors do not reference long-term GDP growth in evaluating expectations for individual common stocks.
- The theoretical proposition that growth rates for all firms converge to overall growth in the economy over the very long horizon does not guide investors' views, and growth rates for utilities can and do exceed GDP growth.

In short, there is no demonstrable evidence that investors look to GDP growth rates in the far distant future in assessing their expectations for common stocks. And while the theoretical assumptions underlying this method contemplate an infinite stream of cash flows, this is simply at odds with the practical circumstances in which real-world investors operate.

Q74. THE DCF MODEL IS BASED ON THE ASSUMPTION OF AN INFINITE STREAM OF CASH FLOWS. WHY WOULDN'T A TRANSITION TO GDP GROWTH MAKE SENSE?

A74. First, this view confuses the theory underlying the DCF model with the practicalities of its application in the real world. While the notion of long-term growth should presumably relate to the specific firm at issue, or at the very least to a particular industry, there are no long-term growth projections available for the companies in electric utility industry, or the broader market, as a whole. By applying the DCF model in a way that is inconsistent with the information that is available to investors and how they use it, the use of GDP growth places the theoretical assumptions of a financial model ahead of investor behavior. The only relevant growth rate is the growth rate used by investors. Investors do not have clarity to see far into the future, and there is little to no evidence to suggest that investors share the view that growth in GDP must be considered a limit on earnings growth over the long-term.

Second, arguments concerning the "sustainability" of any individual growth rate for a single firm in the S&P 500 miss the point. The growth rate underlying the market cost of equity represents a weighted average of the expectations for the dividend paying firms in the S&P 500. Within this large group of firms, growth expectations for some firms may be extremely anemic, while projections for other firms are considerably more optimistic. In addition, growth rates for one company may moderate over time, while for others they may increase. Finally, the composition of the S&P 500 is not static. As a result, formerly successful firms are supplanted by new firms with potential for high growth (*e.g.*, Sears is supplanted by Amazon, or Blockbuster is supplanted by Netflix). On balance, however, the growth rates used in my CAPM study are representative of the consensus expectations for the dividend paying firms in the S&P 500 Index <u>as a whole</u>. This contradicts Dr. Woolridge's position that investors' growth expectations should be constrained by a threshold tied to GDP.

Q75. ARE LONG-TERM GDP GROWTH RATES COMMONLY REFERENCED AS A DIRECT GUIDE TO FUTURE EXPECTATIONS FOR SPECIFIC FIRMS?

A75. No. Certainly investors consider broad secular trends in economic activity as one foundation for their expectations for a particular industry or firm. But the idea that investment advisory services view GDP growth as a direct guide to long-term expectations for a particular firm – much less every firm in an entire industry – is not borne out by evidence.

In contrast to this notion, in the financial media one observes many references to three-to-five year EPS growth forecasts for individual companies and very few references to long-term GDP forecasts. Long-term GDP growth rates are simply not discussed within the context of establishing investors' expectations for individual firms. For example, Value Line reports are routinely relied on as an important guide to apply the DCF model.[100] But despite Dr. Woolridge's suggestion that GDP has a fundamental role in shaping investors' growth estimates, Value Line does not even mention trends in GDP in its evaluation of the firms in the electric utility industry, for example. Value Line's singleness of purpose is to inform investors of the pertinent factors that impact future expectations specific to each of the common stocks it covers. If the trajectory of GDP growth out to the year 2040 and beyond had direct relevance in investors' evaluation of common stocks, it would be logical to assume that Value Line or other securities analysts would give at least passing mention to this fact. But they do not.

Q76. HOW MUCH CONFIDENCE WOULD INVESTORS BE LIKELY TO PLACE ON LONG-TERM GDP PROJECTIONS?

A76. Very little. Investors understand the complexities and inherent inaccuracies involved in forecasting, and that such uncertainties are significantly compounded for a long-term time horizon. Consider the example of IHS Global Insight, which is perhaps the world's foremost econometric forecasting service. IHS Global Insight currently publishes GDP projections for the U.S. economy for the next thirty years, but for other important economic variables (*e.g.*, bond yields) their forecast simply holds projected values constant after a five-year horizon.

[100] As noted in *New Regulatory Finance*, "Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors." Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 71.

Q77. DID THE FOUNDER OF THE DCF APPROACH SUPPORT THE USE OF A GENERIC LONG-TERM GROWTH RATE, SUCH AS THE GDP GROWTH?

A77. No. Professor Myron J. Gordon, who originated the DCF approach, concluded that reference to a generic long-term growth rate, such as Dr. Woolridge advocates, was unsupported.[101] More specifically, Dr. Gordon concluded that any assumption of a single time horizon for a transition to a generic long-term growth rate was highly questionable and failed to reduce error in DCF estimates. Instead, Dr. Gordon specifically recognized that, "it is the growth that investors expect that should be used" in applying the DCF model, and he concluded:

> A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth."[102]

Similarly, a recent study reported in the *Journal of Investing* determined that there is no correlation between stock market returns or earnings growth and GDP, suggesting that investors' expectations built into observable share prices are driven by valuation measures, and not expected economic growth.[103]

Q78. PLEASE SUMMARIZE YOUR OBJECTION TO DR. WOOLRIDGE'S REFERENCE TO GDP GROWTH RATES IN YOUR MARKET DCF ANALYSIS?

A78. Dr. Woolridge presents no meaningful information to suggest that earnings growth rates of companies are limited to the growth rate in GDP. There is no link between Dr. Woolridge's GDP growth rate ceiling and the actual expectations of investors in the capital markets, which are the determining factor in any analysis of a fair ROE

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[101] Myron J. Gordon, "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* (1974) at 100-01.
[102] *Id.* at 89.
[103] Joachim Klement, "What's Growth Got to Do with It? Equity Returns and Economic Growth," *Journal of Investing*, Vol. 24, No. 2 (Summer 2015): 74:78.

Q79. DR. WOOLRIDGE SAYS THAT YOUR EXPECTED EARNINGS APPROACH IS FLAWED DUE TO UNREGULATED OPERATIONS OF THE PROXY GROUPS AND DUE TO DIFFERENCES IN M/B.[104] DO YOU AGREE WITH THIS ASSESSMENT?

A79. Not at all. The appeal of the expected earnings approach is that it does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior. While companies in the proxy groups may have varying levels of unregulated operations, they have all been judged to be of comparable overall risk and this condition overrides specific differences between them.

Again, market-to-book ratios have no place in applying the expected earnings approach. Traditional applications of the expected earnings approach do not involve a M/B adjustment. Nor is such an adjustment recommended in recognized texts such as *New Regulatory Finance.*[105] FERC has also rejected similar arguments raised by Dr. Woolridge, finding that, "considering market-to-book ratios in an expected earnings study is inconsistent with the purpose of the comparable earnings model."[106]

Q80. DR. WOOLRIDGE CRITICIZES YOUR USE OF A LOW-RISK GROUP OF NON-UTILITY COMPANIES AS AN ROE CHECK OF REASONABLENESS (AT 83). ARE HIS CRITICISMS JUSTIFIED?

[104] Woolridge Direct at 82-83.
[105] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006).
[106] *Martha Coakely, et al.*, Opinion No. 531-B, 150 FERC ¶ 61,165 at P 132 (2015).

A80. Not at all. The implication that an estimate of the required return for firms in the competitive sector of the economy is not useful in determining the appropriate return to be allowed for rate-setting purposes is wrong and inconsistent with reality, investor behavior, and the *Bluefield* and *Hope* decisions. In fact, returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets.

The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives, which include all other securities available in the stock, bond or money markets. Consistent with this view, Dr. Woolridge noted the Supreme Court's economic standards and concluded that the fair rate of return on equity should be "comparable to returns investors expect to earn on other investments of similar risk."[107] Clearly the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment and there are a plethora of other "investments of comparable risk" available to investors beyond those in the utility industry.

True enough, utilities are sheltered from competition, but they undertake other obligations and lose the ability to set their own prices and decide when to exit a market. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility.[108]

Q81. DOES THE MARCH 10, 2015 REPORT FROM MOODY'S CITED BY DR. WOOLRIDGE (AT 62) SUPPORT A DRAMATIC DROP IN THE COMPANY'S ALLOWED RETURN FROM THOSE CURRENTLY BEING AUTHORIZED FOR COMPARABLE UTILITIES?

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[107] Woolridge Direct at 2-3.
[108] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

A81. No. The Moody's report discusses only very generally the impacts of a "slow" decline in utilities' authorized ROEs, and how regulators may lower authorized ROEs without harming utilities' cash flow, such as by "targeting depreciation." The Moody's report does not identify a cost of equity for regulated utilities at all, much less discuss a cost of equity for Kentucky Power, which is not even mentioned in the report. In my view, the Moody's report offers no relevant information about a fair ROE in this proceeding, and it certainly does not support the values recommended by the ROE Witnesses.

Q82. DOES THE MOODY'S REPORT INDICATE THAT EQUITY INVESTORS WOULD NOT BE CONCERNED IF THE COMPANY'S ROE WERE LOWERED TO THE LEVELS RECOMMENDED BY THE ROE WITNESSES?

A82. No. I believe no one can make such an inference based on this report. First, it is important to note that the primary mission of credit rating agencies like Moody's is to provide *debt holders* with an accurate benchmark of the relative risks of default associated with long-term bonds and other debt securities. As the report cited by Dr. Woolridge clearly observes, Moody's evaluation is premised "from the perspective of a probability of a default and expected loss given default."[109]

Bondholders, the constituency represented by Moody's, do not share in a utility's net income or profits. As a result, Moody's focus is on cash flows, which are viewed "as a more important rating driver."[110] On the other hand, *equity investors* are intensely focused on the ability of the utility to generate earnings, dividends and growth. This difference in the characteristics and priorities between debt and equity securities gives rise to the considerable distinction in the

[109] Moody's Investors Service, "Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles," *Sector In-Depth* (March 2015).
[110] *Id.* Moody's further clarified that it defines credit risk "as the risk that an entity will not meet its contractual, financial obligations as they come due and any estimated financial loss in the event of default. Credit ratings do not address any other risk …."

risks faced by debt holders and equity investors. While a moderate and gradual downturn in ROEs may not pose an immediate threat to the cash flow protection underlying the credit ratings on a utility's debt, it would have an immediate, negative impact on returns to common stockholders.

Q83. DR. WOOLRIDGE CLAIMS THAT RECENT TRENDS IN ELECTRIC UTILITY BOND RATING ACTIONS AND HISTORICAL EARNED RETURNS SUPPORT HIS ROE RECOMMENDATION.[111] DO GENERAL TRENDS IN UTILITY CREDIT RATINGS OR HISTORICAL EARNED RETURNS PROVIDE ANY JUSTIFICATION FOR AN 8.6% ROE FOR KENTUCKY POWER IN THIS CASE?

A83. No. The factors that lead to a utility company's bond rating depend on a host of considerations, including the nature of the regulatory environment, diversity and health of the service area economy, availability of supportive recovery mechanisms, weather or geographical challenges, and so on. Thus, there is no direct connection between the general pattern of credit ratings actions for other utilities in the industry and the specific determination of a fair ROE for Kentucky Power in this case. In fact, the wide disparity between Dr. Woolridge's recommendations and the benchmarks discussed earlier in my testimony indicate that an 8.6% ROE would be entirely inconsistent with the factual circumstances leading to the pattern of credit ratings actions displayed in Dr. Woolridge's Figure 6.

Moreover, Dr. Woolridge's analysis of historical earned returns is distorted and provides no useful guidance as to investors' future expectations or requirements. In his analysis, Dr. Woolridge says the "median earned ROE for the year 2016 for the companies in the Electric and McKenzie are 9.3% and 9.4%,

[111] Woolridge Direct at 61.

respectively, as shown in Exhibit JRW-4."[112] A detailed review of Exhibit JRW-4 casts significant doubt on the usefulness of these values, however. Included in the "Return on Equity" column for Dr. Woolridge's Electric Proxy Group are returns of -66.20% (FirstEnergy), -6.73% (Entergy), 3.16% (WEC Energy), and several other values in the 3%-5% range. In the McKenzie Proxy Group panel, there are five "Return on Equity" values in the 2%-5% range. Because these values clearly do not provide a reasonable guide to investors' return requirements, Dr. Woolridge's analysis in this area is not reliable and should be ignored.

III. RESPONSE TO MR. BAUDINO

Q84. HOW DID MR. BAUDINO ARRIVE AT HIS RECOMMENDED COST OF EQUITY?

A84. Mr. Baudino recommended an ROE of 8.85% based exclusively on his application of the constant growth DCF model. He included a CAPM analysis for "additional information" but did not incorporate the results of the CAPM directly in his recommendation.[113] Mr. Baudino applied these methods to the same proxy group I did, but for three utilities that he excluded due to perceived data issues.[114]

Q85. WHAT IS YOUR ASSESSMENT OF MR. BAUDINO'S ROE TESTIMONY AND RECOMMENDATION?

A85. Mr. Baudino's recommendation is not realistic. Several specific factors detract from his analysis. First and foremost, Mr. Baudino fails to apply sufficient checks of reasonableness to test his DCF results. His CAPM approach is significantly flawed and he ignores other accepted benchmarks such as the utility risk premium, expected earnings, and ECAPM methodologies, or a review of non-

[112] *Id.*
[113] Baudino Direct at 3.
[114] Mr. Baudino eliminated AVANGRID, Emera, and Fortis.

utility outcomes. Had Mr. Baudino employed these other approaches, he would have seen that his DCF-based result was not reasonable.

A. Discounted Cash Flow Model

Q86. WHAT ARE THE SPECIFIC DEFECTS THAT YOU HAVE IDENTIFIED IN MR. BAUDINO'S DCF ANALYSIS?

A86. While Mr. Baudino's application of the DCF model is fairly straightforward, there are several problems with his approach. First, I do not agree with his decision to eliminate three companies from my proxy group. Second, he repeats the mistakes made by Dr. Woolridge in giving weight to DPS growth rates and in conducting an incomplete "br" growth study. Finally, his DCF results are based on a decision to average all individual growth rates together and compute a single ROE estimate for each growth rate source. This approach masks the presence of extreme data and biases his results downward.

Q87. PLEASE ELABORATE ON YOUR DISAGREEMENT WITH MR. BAUDINO'S PROXY GROUP?

A87. I do not agree with Mr. Baudino's decision to exclude three eligible utilities from my proxy group in forming his sample. He rejects AVANGRID because "there is not enough Value Line information to include this company in the proxy group."[115] AVANGRID is a major utility with a market capitalization of $15 billion. Its subsidiaries are well known to investors and include Central Maine Power, New York State Electric & Gas, Rochester Gas and Electric, and United Illuminating. AVANGRID has a stable dividend policy, and while Value Line may not currently report projected growth rates, this data is available from comparable sources such as Zacks and IBES, which were both relied on by Mr. Baudino. It would have been easy to substitute "No Meaningful Figure" for

[115] Baudino Direct at 17-18.

AVANGRID's Value Line growth rate and continue the DCF calculation with the other two growth rate sources. Indeed, this is precisely the approach taken by Mr. Baudino in the case of PPL Corporation which, like AVANGRID, lacked a Value Line projected growth rate. For PPL Corporation, Mr. Baudino input "NMF" for its missing Value Line rate and continued the DCF process with growth rates from Zacks and IBES.[116]

Mr. Baudino excludes Emera, Inc. because, due to its 2016 acquisition of TECO Energy, it "is a different company today from what it was in 2015 and its expected short-term growth in dividends and revenues reflect this."[117] This viewpoint is mistaken on many levels. First, the acquisition of TECO Energy was completed on July 1, 2016, over 15 months ago. All related impacts are fully incorporated in the forecasts and projections of investor information services, including Value Line, Zacks, and IBES. Of course, Emera is not the same company it was prior to the merger but that is not the point; the point is that investors are fully aware of the changes it has undergone and all relevant data, going forward, reflects these impacts. This circumstance is no different than that facing Southern Company, which coincidentally, also completed a merger on July 1, 2016 (with AGL Resources). Southern Company is also not the same company it was in 2015, but exercising a clear double standard, Mr. Baudino left them in his proxy group.[118]

Mr. Baudino cites a sizeable increase in Emera's revenues following the TECO Energy acquisition and implies that this increase is short-term in nature and not reflective of long-term conditions.[119] Again, Mr. Baudino misses the point. Of course, revenues will increase as the new company is added to existing

[116] Exhibit RAB-4, page 1.
[117] Baudino Direct at 18.
[118]
[119] *Id.*

operations, but so will expenses and investment. Mr. Baudino's focus on increased revenues is misguided and misleading; the proper focus is on net earnings and, in this light, Emera is clearly not an outlier. The 8.5% earnings growth rate for Emera cited (and excluded) by Mr. Baudino is in line with other rates he considered acceptable: 9.5% for NextEra Energy; 8.5% for Dominion Energy; and 8.5% and 8.0% for Sempra Energy.[120]

Finally, Mr. Baudino eliminates Fortis, Inc. from his proxy group stating that, due to its 2016 acquisition of ITC Holdings, its revenues and total capital will increase significantly.[121] My rebuttal to Mr. Baudino's misleading claims are the same here as above. Simple arithmetic tells us that revenues and investment will increase due to an acquisition, but it is the forward-looking impact on net earnings (after increased expenses and costs are also considered) that is most important to investors. As noted above, the 9.0% projected earnings growth rate for Fortis is not out of line with other rates accepted by Mr. Baudino. In removing AVANGRID, Emera, and Fortis from his proxy group, Mr. Baudino is inconsistent in the application of his selection criteria. His decision appears to be based more on the fact that the rates for the three excluded companies are at the upper end of the growth rate range. Such an approach is capricious and unfair and should be rejected.

Q88. MR. BAUDINO CONSIDERED DIVIDEND DATA IN THE GROWTH RATE PORTION OF HIS DCF ANALYSIS. IS THIS APPROACH LIKELY TO DISTORT HIS DCF RESULTS?

A88. Yes. As discussed earlier in my response to Dr. Woolridge, growth rates in DPS are not likely to provide a meaningful guide to investors' current growth expectations. The importance of earnings in evaluating investors' expectations

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[120] Exhibit RAB-4.
[121] Baudino Direct at 18.

and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in EPS is far more influential than trends in DPS.

Q89. MR. BAUDINO ALSO PRESENTED SUSTAINABLE, "BR" GROWTH RATES (EXHIBIT RAB-4, P. 1). SHOULD THE KPSC PLACE ANY WEIGHT ON THESE VALUES?

A89. No. In the same way as I explained earlier in my rebuttal to Dr. Woolridge, Mr. Baudino's "br" growth rates are downward biased because he failed to recognize the impact of year-end returns reported by Value Line. Furthermore, like Dr. Woolridge, Mr. Baudino failed to consider the impact of additional issuances of common stock in his analyses of the sustainable growth rate. Because Mr. Baudino ignored these adjustments, his internal, "br" growth rates are distorted and should be ignored. In fact, Mr. Baudino himself did not rely on sustainable "br" growth rates in his final DCF application.[122]

Q90. ARE THERE OTHER PROBLEMS WITH MR. BAUDINO'S DCF ANALYSIS?

A90. Yes. Another flaw in Mr. Baudino's DCF analyses was his decision to average all individual growth rates and then compute a single DCF estimate for each growth rate source. Each growth rate represents a stand-alone estimate of investors' future expectations, and each value should be evaluated on its own merits. The fact that an average of several growth rates might produce a DCF estimate that could be considered reasonable does not absolve the need to evaluate each underlying growth rate separately.

For example, consider a utility with a dividend yield of 3.5% and three hypothetical growth estimates of 0.0%, 6.5%, and 14.0%. Under Mr. Baudino's

[122] Baudino Direct at 21.

method, the DCF estimate would be computed by adding the 6.8% average of the three individual growth rates to the dividend yield, resulting in a cost of equity estimate of 10.3%. The problem with this method is that it disguises the fact that two of the underlying growth rates – 0.0% and 14.0% – do not provide a meaningful guide to investors' expectations. Rather than averaging the good with the bad, each implied cost of equity estimate (in this example, 3.5%, 10.0%, and 17.5%) should be evaluated on a stand-alone basis.[123] Mr. Baudino simply calculated the average of the individual growth rates with no consideration for the reasonableness of the underlying data. Because Mr. Baudino failed to perform this essential step, his DCF analysis included individual growth rates that do not reflect investors' expectations. Therefore, his results are biased downward.

Q91. CAN YOU SHOW THE DOWNWARD BIAS IN MR. BAUDINO'S CONSTANT GROWTH ANALYSIS?

A91. Yes. For example, Mr. Baudino reports a First Call/IBES growth rate of 0.04% for PPL Corporation.[124] Combining this growth rate with PPL's corresponding dividend yield of 4.13% results in a cost of equity estimate of 4.17%. Similarly, combining Public Service Enterprise Group's First Call/IBES growth rate of 0.57% with its dividend yield of 3.86% produces an ROE estimate of 4.43%. These implied costs of equity are less than, or do not sufficiently exceed current and projected yields on public utility bonds. As a result, these illogical growth measures should have been removed from Mr. Baudino's constant growth DCF analysis.

[123] The implied cost of equity estimates are calculated as the sum of the dividend yield (3.5%) and the respective growth rates (0.0%, 6.5%, and 14.0%).
[124] Exhibit RAB-4.

B. Capital Asset Pricing Model

Q92. WHAT IS THE BIGGEST ISSUE YOU HAVE WITH MR. BAUDINO'S CAPM ANALYSIS?

A92. Mr. Baudino's CAPM results are simply so low they should be rejected outright. Results from his current market premium CAPM range from 6.90% to 7.15%; while results from his historic market premium model range from 5.99% to 7.32%.[125] These outcomes are not legitimate ROE estimates.

Q93. CAN YOU IDENTIFY DEFECTS IN MR. BAUDINO'S CAPM METHODOLOGY?

A93. Yes. For instance, Mr. Baudino bases his risk-free rate on 5-year and 20-year Treasury securities when it is more appropriate to rely on the longer-term 30-year Treasury bond. As Dr. Woolridge states:

> The yield on long-term U.S. Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. The yield on long-term U.S. Treasury bonds, in turn, has been considered to be the yield on U.S. Treasury bonds with 30-year maturities.[126]

Mr. Baudino's reliance on government debt with shorter maturities serves to unfairly deflate his CAPM results.

Next, Mr. Baudino attempts to develop a forecasted market return, which is a laudable goal. However, instead of simply relying on Value Line earnings forecasts, he introduces book value growth into the process. As I describe above, growth in EPS is the most influential driver of investors' long-term expectations. Adding book value growth only serves to depress his market return estimate, especially given that the earnings growth rate is 10.5% and the book value growth

[125] Baudino Direct, Table 3, at 29.
[126] Woolridge Direct at 49.

rate is 7.5%.[127] If Mr. Baudino had left out the book value component, his market return projection would have been much more reasonable, at 11.37%.[128]

Q94. IS THERE ANOTHER SERIOUS PROBLEM ASSOCIATED WITH CAPM ANALYSIS DEVELOPED BY MR. BAUDINO?

A94. Yes, as I mentioned earlier in my response to Dr. Woolridge, the CAPM is an *ex-ante*, or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using data that reflect the expectations of actual investors in the market. Mr. Baudino has recognized that, "There is no real support for the proposition that an unchanging, mechanically applied historical risk premium is representative of current investor expectations and return requirements."[129]

Nevertheless, at least part of Mr. Baudino's application of the CAPM method was based on *historical* – not projected – rates of return (Exhibit RAB-6). Because Mr. Baudino's backward-looking analysis ignores the returns investors are currently requiring in the capital markets, the resulting CAPM estimates fall woefully short of investors' current required rate of return.

Q95. IS THERE ANY MERIT TO MR. BAUDINO'S ARGUMENT (AT 39) THAT YOUR ANALYSIS OF THE MARKET RATE OF RETURN SHOULD NOT HAVE BEEN LIMITED SOLELY TO THE DIVIDEND PAYING FIRMS IN THE S&P 500?

A95. No. As Mr. Baudino recognized (at 15-16), under the constant growth form of the DCF model, investors' required rate of return is computed as the sum of the dividend yield over the coming year plus investors' long-term growth expectations. Because the dividend yield is a key component in applying the DCF

[127] Exhibit RAB-5, page 2.
[128] *Id.* Earnings growth of 10.50% plus the average dividend yield of 0.87% is 11.37%.
[129] *Direct Testimony and Exhibits of Richard A. Baudino*, Case No. 2012-00221 & Case No. 2012-00222, at p. 28 (October 2012).

model, its usefulness is hampered for firms that do not pay common dividends. Accordingly, my DCF analysis of the market rate of return properly focused on the dividend paying firms included in the S&P 500.

Meanwhile, Mr. Baudino (at 25-26) predicated his DCF analysis of the market rate of return on the companies followed by Value Line. Of the U.S. firms in Value Line, amounting to approximately 1,500 companies, approximately 500 do not pay common dividends. In other words, one-third of the companies that underpin Mr. Baudino's DCF analysis do not have the data necessary to implement this approach. Further, many of these firms are relatively small and lack a meaningful operating history. As a result, there is also greater uncertainty associated with estimating the future growth expectations that are central to the application of the DCF method. Taken together, these factors impugn the reliability of Mr. Baudino's market risk premium and confirm my decision to restrict the analysis to the established, dividend paying firms in the S&P 500.

Q96. DO THE ARGUMENTS ADVANCED BY MR. BAUDINO UNDERMINE THE NEED FOR A SIZE ADJUSTMENT AS PART OF THE CAPM AND ECAPM ANALYSES?

A96. No. Mr. Baudino simply observes that the average beta associated with the lower size deciles examined by Duff & Phelps is greater than the average his proxy group.[130] While I do not dispute the observation, it has no relevance whatsoever to the implications of Duff & Phelps' findings regarding the impact of firm size. The fact that the average beta for smaller size deciles is greater than for 1.00 says nothing about the range of individual beta values underlying this average. Moreover, the size premiums are beta adjusted; meaning that the risk impact of beta values (whether higher or lower than Mr. Baudino's proxy group average)

[130] Baudino Direct at 40.

have been removed. While the size premiums reported by Duff & Phelps were not estimated on an industry-by-industry basis, this provides no basis to ignore this relationship in estimating the cost of equity for utilities. Utilities are included in the companies used by Duff & Phelps to quantify the size premium, and firm size has important practical implications with respect to the risks faced by investors in the utility industry. As Duff & Phelps concluded*:*

> Despite many criticisms of the size effect, it continues to be observed in data sources. Further, observation of the size effect is consistent with a modification of the pure CAPM. Studies have shown the limitations of beta as a sole measure of risk. The size premium is an empirically derived correction to the pure CAPM.[131]

C. Other ROE Issues

Q97. DOES MR. BAUDINO ADVANCE ANY CREDIBLE CRITICISM OF YOUR RISK PREMIUM APPROACH?

A97. No. Mr. Baudino's only observation is that the risk premium method is "imprecise."[132] Of course, this "criticism" applies equally to every model of investor behavior that is used to estimate required returns, including the DCF approach that formed the sole basis for Mr. Baudino's recommendation. The DCF method is only one theoretical approach to gain insight into the return investors require, which is unobservable. While the tautology of the DCF model boils this determination down to the familiar dividend yield and growth rate components, this masks the underlying complexities that accompany any attempt to distill every facet of investors' expectations into a single growth estimate. Mr. Baudino's claim that the DCF is "far more reliable and accurate" is unsubstantiated. While the DCF model is a recognized approach to estimating the cost of equity, it is not without shortcomings and does not otherwise eliminate the

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[131] *Duff & Phelps*, "2016 Valuation Handbook," (2016) at 4-27.
[132] Baudino Direct at 41.

need to examine the results of other methods. As the Indiana Utility Regulatory Commission noted, for example:

> There are three principal reasons for our unwillingness to place a great deal of weight on the results of any DCF analysis. One is . . . the failure of the DCF model to conform to reality. The second is the undeniable fact that rarely if ever do two expert witnesses agree on the terms of a DCF equation for the same utility – for example, as we shall see in more detail below, projections of future dividend cash flow and anticipated price appreciation of the stock can vary widely. And, the third reason is that the unadjusted DCF result is almost always well below what any informed financial analysis would regard as defensible, and therefore require an upward adjustment based largely on the expert witness's judgment. In these circumstances, we find it difficult to regard the results of a DCF computation as any more than suggestive.[133]

Q98. MR. BAUDINO ARGUES THAT THE USE OF FORECASTED INTEREST RATES IN THE ROE ESTIMATION PROCESS IS A PROBLEM BECAUSE THE PROJECTIONS MAY NOT MATERIALIZE.[134] DO YOU AGREE WITH THIS POSITION?

A98. No. As I stated in my Direct Testimony and earlier in this testimony, whether the projections of various services may be proven optimistic or pessimistic in hindsight, is irrelevant in assessing expected interest rates and how they might influence the Company's allowed ROE.

Q99. HOW DO YOU RESPOND TO MR. BAUDINO'S DISCUSSION OF YOUR NON-UTILITY ANALYSIS?

A99. Mr. Baudino makes the statement that utilities "have protected markets, e.g., service territories, and may increase the prices they charge in the face of falling demand or loss of customers."[135] Based on this, Mr. Baudino summarily concluded, "Obviously, the non-utility companies face risks that a lower risk

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[133] *Ind. Michigan Power Co.*, Cause No. 38728, 116 PUR4th, 1, 17-18 (IURC 8/24/1990).
[134] Baudino Direct at 32-35.
[135] *Id.* at 43.

electric company like KPC does not face." In fact, however, investors are quite aware that utilities are not guaranteed recovery of reasonable and necessary costs incurred to provide service and that there are many instances in which utilities are unable to increase rates to fully recoup reasonable and necessary costs, resulting in an inability to earn the allowed ROE – and potentially, even bankruptcy. The simple observation that a firm operates in non-utility businesses says nothing at all about the overall investment risks perceived by investors, which is the very basis for a fair rate of return.

Q100. DOES OBJECTIVE EVIDENCE SUPPORT MR. BAUDINO'S RISK ARGUMENTS?

A100. No. My direct testimony noted that the average corporate credit rating for the Non-Utility Group of "A-" is <u>higher</u> than the "BBB+" average for the Utility Group and the Company.[136] This assessment is confirmed by the review of financial strength values and other objective indicators of investment risk presented in Table 7 to my direct testimony, which consider the impact of competition and market share and demonstrated that, if anything, the Non-Utility Group could be considered <u>less</u> risky in the minds of investors than the common stocks of the proxy group of utilities.

In other words, the objective risk measures specifically cited by Mr. Baudino as being relevant indicators of overall investment risks contradict his assertions regarding the relative risk of the Non-Utility Group. Similarly, Mr. Baudino testified that bond ratings reflect a detailed and comprehensive analysis of the key factors contributing to a firm's overall investment risk, concluding, "Bond and credit ratings are tools that investors use to assess the risk comparability of firms."[137]

[136] McKenzie Direct, Table 7, at 75.
[137] Baudino Direct at 15.

A101. Contradicting Mr. Baudino's unsupported assertion (at 43) that the companies in my Non-Utility Group "face risks that a lower risk electric company like KPC does not face,"

Q101. MR. BAUDINO SAYS THAT AN ADJUSTMENT TO ACCOUNT FOR FLOTATION COSTS IS NOT NECESSARY SINCE "FLOTATION COSTS ARE ALREADY ACCOUNTED FOR IN CURRENT STOCK PRICES."[138] IS THIS A VALID ASSUMPTION?

A102. No. Mr. Baudino's position is akin to arguing that it is not necessary to reflect the utility's entire reasonable and necessary O&M expense in revenue requirements because such actions would be "accounted for" in the stock price. Flotation costs are legitimate expenses and unless a discrete adjustment is made to recognize them, they will not be recovered in the rate setting process.

IV. RESPONSE TO MR. TILLMAN

Q102. DID MR. TILLMAN CONDUCT AN INDEPENDENT EVALUATION OF A FAIR ROE FOR THE COMPANIES?

A103. No. Mr. Tillman did not conduct any analyses of the cost of equity. His testimony was limited to a presentation of selected data concerning previously authorized ROEs. Based on this limited review, Mr. Tillman expressed his concern that a 10.31% ROE for the Company is "excessive."[139]

Q103. DO YOU AGREE WITH MR. TILLMAN THAT ALLOWED ROES PROVIDE ONE BENCHMARK WORTHY OF CONSIDERATION IN THE COMMISSION'S EVALUATION?

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[138] Baudino Direct at 43.
[139] Tillman Direct at 7.

A104. Yes, I do. Importantly, however, such comparisons of allowed ROEs are only one consideration. While this data can be useful in the KPSC's deliberations, it is not a substitute for the detailed analyses presented in my direct testimony.

Q104. DOES THE DATA PRESENTED BY MR. TILLMAN CONFIRM YOUR CONCLUSION THAT DR. WOOLRIDGE'S AND MR. BAUDINO'S RECOMMENDATIONS ARE TOO LOW?

A105. Yes. Mr. Tillman cites an average allowed ROE for vertically integrated utilities of 9.79% for 2014 through the present,[140] which confirms my earlier conclusion that the 8.60% and 8.85% ROE recommendations of the ROE Witnesses fall well below average returns authorized for other utilities, and are insufficient to meet the requirements of regulatory standards.

Q105. FROM YOUR POSITION AS A REGULATORY FINANCIAL ANALYST, WHAT DO YOU MAKE OF MR. TILLMAN'S ADMONITION (AT 7) TO CONSIDER CUSTOMER IMPACTS WHEN ESTABLISHING A FAIR ROE?

A106. First, it is important to note that the determination of the ROE is made by investors in the capital markets, and is not predicated on any notion of costs or savings to customers. The U.S. Supreme Court's regulatory standards embodied in the *Hope* and *Bluefield* decisions represent a balance between the interests of customers and investors, by setting forth the guidelines as to a fair ROE. Meanwhile, Mr. Tillman wrongly suggests that a lower ROE is *per se* in customers' benefit. This is not the case. While a downward-biased ROE may provide the illusion of customer "savings" in the form of a lower revenue requirement in the short-term, the long-term impact of an inadequate ROE can be injurious to customers and the Kentucky economy.

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[140] *Id.* at 11.

As discussed earlier, there is a very real connection between the ROE and the availability of capital, and Mr. Tillman ignores the negative impact that an inadequate ROE would have on investment. The ROE is the primary signal to investors, not only with respect to attracting new capital investment, but also in supporting existing utility operations. If the utility is unable to offer a competitive ROE, existing shareholders will suffer a capital loss as investors take advantage of other, more favorable opportunities, and the utility's stock price would fall. Moreover, as investors' confidence is undermined, the ability of utilities to access equity capital markets and expand investment will suffer. While the Company would undoubtedly continue to meet their service obligations to customers, a downward-biased ROE would send an unmistakable signal to the investment community as they consider whether to commit capital in Kentucky, and at what cost.

Q106. DO YOU AGREE WITH MR. TILLMAN'S ASSESSMENT REGARDING THE IMPACT OF CONSTRUCTION WORK IN PROGRESS ("CWIP")?

A107. No. While Mr. Tillman attempts to distinguish the risks of the Company based on the opportunity to include CWIP in rate base, this is hardly novel or unique to the Company and has been widely utilized since the 1970s to address the impact of construction costs on utilities' financial integrity.

Q107. WHAT IS CWIP?

A108. CWIP consists of investment in facilities built to meet service obligations that are not yet physically providing service. For an electric utility, CWIP can be sizeable as a result of the capital intensity of utility infrastructure investment and the extended construction periods involved with these facilities. During the construction phase, the utility must pay capital carrying costs (interest, dividends, etc.) on the investment in new facilities. These capital carrying costs are typically accrued for future recovery in the form of Allowance for Funds Used During

Construction ("AFUDC"), which is included in rate base at the time the facilities are placed in service. Alternatively, regulators may allow CWIP to be included in rate base and thus permit the utility an opportunity to recover these capital costs through current rates.

Q108. WHAT IS THE FINANCIAL IMPACT OF CWIP?

A109. If CWIP is included in rate base, the utility's revenue requirements are increased by the capital costs associated with the new construction. As a result, since customers pay the capital carrying costs of CWIP in current rates, capitalized AFUDC is not added to plant cost. From the utility's standpoint, current cash flow is higher than it would have been otherwise. As a result, including CWIP in rate base improves a utility's cash flow and increases revenue requirements during the construction phase; however, this increase is offset in the future by the lower rate base that results from eliminating capitalized AFUDC.

While the level of a utility's earnings does not differ dramatically depending on whether or not CWIP is included in rate base, the cash flow implications can be significant, especially in the case of a large construction program. To finance the costs of construction, utilities such as the Company must obtain financing in the form of common equity or long-term debt. If CWIP is not included in rate base, no cash is generated from current rates to meet the interest and dividend payments associated with these securities, which in turn must be financed.

The uncertainties that investors associate with cost deferrals and a deterioration in earnings quality are significant and many of the key indicators relied on by securities analysts and bond rating agencies focus on measures of cash flow. As a result, the greater risk associated with higher levels of non-cash earnings (*i.e.*, AFUDC) would ultimately be reflected in higher rates of return required by investors. Investors recognize that including CWIP in rate base is an important tool that supports the utility's financial integrity and attenuates some of the financial risks associated with new infrastructure investment.

Q109. IS THERE ANY MERIT TO MR. TILLMAN'S CONTENTION (AT 9) THAT INCLUDING CWIP IN RATE BASE "SHIFTS RISKS ONTO RATEPAYERS?"

A110. No. Including CWIP in rate base will ease the financial pressure associated with the Company's capital projects by improving cash flow and providing greater regulatory certainty. While instrumental in supporting financial integrity and ability to attract capital, including CWIP will not have a measurable impact on the overall investment risks of the Company or investors' required rate of return. Including CWIP in rate base changes only the timing of cost recovery for projects included in CWIP. Accordingly, CWIP does not shift risks to ratepayers, as alleged by Mr. Tillman.

Q110. HAVE OTHER REGULATORS RECOGNIZED THE POTENTIAL BENEFITS ASSOCIATED WITH INCLUDING CWIP IN RATE BASE?

A111. Yes. Investors recognize that it is not uncommon for regulators to include CWIP in rate base when establishing rates. A study by the Edison Electric Institute observed that:

> The inclusion of CWIP in rate base improves cash flow and reduces future rate shocks. This practice also reduces the losses that a utility experiences making large plant additions under historical test year rates. Monitoring by the Edison Electric Institute has found that states that have recently allowed the inclusion of CWIP in rate base include CO, FL, GA, IN, KS, KY, LA, MI, MO, NC, NM, NV, SD, TN, VA, and WV.[141]

Accordingly, the cost of equity estimates developed for the proxy companies already reflects any impact associated with the opportunity to earn a return on CWIP. FERC has also recognized that including CWIP balances the

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[141] Edison Electric Institute, *Forward Test Years for US Electric Utilities* (August 2010).

interest of investors and customers, and the Commission has routinely allowed electric utilities to include CWIP in rate base.[142] FERC noted in *Order No. 679* that including CWIP in rate base provides "up-front regulatory certainty, rate stability and improved cash flow" that encourage investment by "easing the financial pressures" associated with construction programs.[143]

Q111. IS MR. TILLMAN'S POSITION WITH RESPECT TO CWIP CONSISTENT WITH ESTABLISHED PRECEDENT IN KENTUCKY?

A112. No. Mr. Tillman's recommendations conflict with the KPSC's long-established support for including CWIP without any downward adjustment to the Company's ROE. Mr. Tillman has presented no evidence that would suggest the KPSC's longstanding practice no longer benefits customers or would otherwise undermine a constructive regulatory policy that is widespread in the industry. Moreover, while CWIP is supportive of the Company's credit standing, it does not allow recovery of a return on construction expenditures outside of a rate proceeding. As a result, there can be a significant lag between the time that expenditures are incurred and when they are included in CWIP, which is exacerbated for utilities with large capital expenditure programs, such as the Company. Mr. Tillman fails to address these realities, which further disprove his assessment and recommendations.

Q112. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A113. Yes, it does.

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[142] *Construction Work in Progress for Public Utilities; Inclusion of Costs in Rate Base*, Order No. 298, FERC Stats. & Regs. ¶ 30,455 (1983), order on reh'g, 25 FERC ¶ 61,023 (1983).

[143] *Order No.679* at P. 115. *See also, Order No. 679-A* at PP. 114-115.

Appendix A

STATE ALLOWED ROEs **Exhibit No. 12**
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RRA INTEGRATED ELECTRIC UTILITIES

(24-Months Ended September 30, 2017)

	Company	State	Date	Allowed ROE	Adder / Penalty	Base ROE
1	Wisconsin Public Service Corp.	WI	11/19/15	10.00%	0.00%	10.00%
2	Consumers Energy Co.	MI	11/19/15	10.30%	0.00%	10.30%
3	Mississippi Power	MS	12/03/15	9.23%	0.00%	9.23%
4	Northern States Power Co - WI	WI	12/03/15	10.00%	0.00%	10.00%
5	DTE Electric Co.	MI	12/11/15	10.30%	0.00%	10.30%
6	Portland General Electric Co.	OR	12/15/15	9.60%	0.00%	9.60%
7	Southwestern Public Service Co	TX	12/17/15	9.70%	0.00%	9.70%
8	Avista Corp.	ID	12/18/15	9.50%	0.00%	9.50%
9	PacifiCorp	WY	12/30/15	9.50%	0.00%	9.50%
10	MDU Resources Group	ND	01/05/16	10.50%	0.00%	10.50%
11	Avista Corp	WA	01/06/16	9.50%	0.00%	9.50%
12	Entergy Arkansas	AR	02/23/16	9.75%	0.00%	9.75%
13	Virginia Electric and Power	VA	(a)	(a)	(a)	9.60%
14	Indianapolis Power & Light Co.	IN	03/16/16	9.85%	-0.15%	10.00%
15	El Paso Electric Co.	NM	06/08/16	9.48%	0.00%	9.48%
16	Virginia Electric and Power	VA	(b)	(b)	(b)	9.60%
17	Northern Indiana Public Service Co.	IN	7/18/2016	9.98%	0.00%	9.98%
18	Kingsport Power Co.	TN	08/09/16	9.85%	0.00%	9.85%
19	UNS Electric	AZ	08/18/16	9.50%	0.00%	9.50%
20	PacifiCorp	WA	09/01/16	9.50%	0.00%	9.50%
21	Upper Peninsula Power	MI	09/08/16	10.00%	0.00%	10.00%
22	Public Service Co. of New Mexico	NM	09/28/16	9.58%	0.00%	9.58%
23	Appalachian Power Co.	VA	10/06/16	9.40%	0.00%	9.40%
24	Madison Gas & Electric Co.	WI	11/09/16	9.80%	0.00%	9.80%
25	Public Service Co. of Oklahoma	OK	11/10/16	9.50%	0.00%	9.50%
26	Wisconsin Power & Light Co.	WI	11/18/16	10.00%	0.00%	10.00%
27	Florida Power & Light Co.	FL	11/29/16	10.55%	0.00%	10.55%
28	Liberty Utilities	CA	12/01/16	10.00%	0.00%	10.00%
29	Duke Energy Progress	SC	12/07/16	10.10%	0.00%	10.10%
30	Black Hills Colorado Electric	CO	12/19/16	9.37%	0.00%	9.37%
31	Sierra Pacific Power Co.	NV	12/22/16	9.60%	0.00%	9.60%
32	Virginia Electric and Power	NC	12/22/16	9.90%	0.00%	9.90%
33	Avista Corporation	ID	12/28/16	9.50%	0.00%	9.50%
34	Appalachian Power Co.	VA	12/30/16	10.00%	0.00%	10.00%
35	MDU Resources Group	WY	01/18/17	9.45%	0.00%	9.45%
36	DTE Electric Co.	MI	01/31/17	10.10%	0.00%	10.10%
37	Tucson Electric Power Co.	AZ	02/24/17	9.75%	0.00%	9.75%
38	Virginia Electric and Power	VA	(c)	(c)	(c)	9.40%
39	Consumers Energy Co.	MI	02/28/17	10.10%	0.00%	10.10%
40	Otter Tail Power Co.	MN	03/02/17	9.41%	0.00%	9.41%
41	Oklahoma Gas and Electric Co.	OK	03/20/17	9.50%	0.00%	9.50%
42	Gulf Power Co.	FL	04/04/17	10.25%	0.00%	10.25%
43	Kansas City Power & Light	MO	05/03/17	9.50%	0.00%	9.50%
44	Northern States Power Co.	MN	05/11/17	9.20%	0.00%	9.20%
45	Oklahoma Gas and Electric Co.	AR	05/18/17	9.50%	0.00%	9.50%
46	Idaho Power Co.	ID	05/31/17	9.50%	0.00%	9.50%
47	Virginia Electric and Power	VA	(d)	(d)	(d)	9.40%
48	MDU Resources Group, Inc.	ND	06/16/17	9.65%	0.00%	9.65%
49	Kentucky Utilities Co.	KY	06/22/17	9.70%	0.00%	9.70%
50	Louisville Gas and Electric Co.	KY	06/22/17	9.70%	0.00%	9.70%
51	Arizona Public Service Co.	AZ	08/15/17	10.00%	0.00%	10.00%
52	Virginia Electric and Power	VA	09/01/17	9.40%	0.00%	9.40%

Range of Reasonableness	**9.20%**	**--**	**10.55%**
Midpoint		**9.88%**	
Average		**9.73%**	

STATE ALLOWED ROEs **Exhibit No. 12**
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RRA INTEGRATED ELECTRIC UTILITIES

Notes

(a) Adjusted to condense the following duplicative project-specific ROE orders:

	State	Date	Allowed ROE	Adder / Penalty	Base ROE
Virginia Electric and Power	VA	2/29/2016	11.60%	2.00%	9.60%
Virginia Electric and Power	VA	2/29/2016	10.60%	1.00%	9.60%
Virginia Electric and Power	VA	2/29/2016	10.60%	1.00%	9.60%
Virginia Electric and Power	VA	2/29/2016	10.60%	1.00%	9.60%
Virginia Electric and Power	VA	3/29/2016	9.60%	0.00%	9.60%

(b) Adjusted to condense the following duplicative project-specific ROE orders:

	State	Date	Allowed ROE	Adder / Penalty	Base ROE
Virginia Electric and Power	VA	6/30/2016	10.60%	1.00%	9.60%
Virginia Electric and Power	VA	6/30/2016	9.60%	0.00%	9.60%

(c) Adjusted to condense the following duplicative project-specific ROE orders:

	State	Date	Allowed ROE	Adder / Penalty	Base ROE
Virginia Electric and Power	VA	2/27/2017	11.40%	2.00%	9.40%
Virginia Electric and Power	VA	2/27/2017	9.40%	0.00%	9.40%
Virginia Electric and Power	VA	2/27/2017	10.40%	1.00%	9.40%
Virginia Electric and Power	VA	2/27/2017	10.40%	1.00%	9.40%
Virginia Electric and Power	VA	2/27/2017	10.40%	1.00%	9.40%

(d) Adjusted to condense the following duplicative project-specific ROE orders:

	State	Date	Allowed ROE	Adder / Penalty	Base ROE
Virginia Electric and Power	VA	6/1/2017	9.40%	0.00%	9.40%
Virginia Electric and Power	VA	6/30/2017	9.40%	0.00%	9.40%
Virginia Electric and Power	VA	6/30/2017	10.40%	1.00%	9.40%

Source: Regulatory Research Associates, "Major Rate Case Decisions," *Regulatory Focus* (Jan. 14, 2016; Jan. 18, 2017); S&P Global, "Major Rate Case Decisions," *RRA Regulatory Focus* (Oct. 26, 2017).

STATE ALLOWED ROEs **Exhibit No. 13**
Page 1 of 1

UTILITY GROUP

	Company	(a) Allowed ROE		
1	Alliant Energy		10.50%	
2	Ameren Corp.		9.15%	
3	American Elec Pwr		10.28%	
4	AVANGRID, Inc.		9.23%	
5	CMS Energy Corp.		10.10%	
6	Dominion Energy		10.90%	
7	DTE Energy Co.		10.10%	
8	Duke Energy Corp.		10.31%	
9	Emera Inc.		NA	
10	Eversource Energy		9.52%	
11	Fortis, Inc.		9.31%	
12	NextEra Energy, Inc.		10.60%	
13	PPL Corp.		9.70%	
14	Pub Sv Enterprise Grp.		10.30%	
15	SCANA Corp.		10.07%	
16	Sempra Energy		10.20%	
17	Southern Company		12.50%	
18	Vectren Corp.		10.28%	
	Range of Reasonableness	**9.15%**	--	**12.50%**
	Midpoint		**10.83%**	
	Average		**10.18%**	

(a) The Value Line Investment Survey (Jul. 28, Aug. 18 & Sep. 15, 2017).

EXPECTED EARNINGS APPROACH

Exhibit No. 14
Page 1 of 1

UTILITY GROUP

	Company	(a) Expected Return on Common Equity	(b) Mid-Year Adjustment Factor	(c) Adjusted Return on Common Equity
1	Alliant Energy	13.0%	1.0044	13.1%
2	Ameren Corp.	10.0%	1.0196	10.2%
3	American Elec Pwr	11.0%	1.0208	11.2%
4	AVANGRID, Inc.	5.0%	1.0064	5.0%
5	CMS Energy Corp.	13.5%	1.0356	14.0%
6	Dominion Energy	19.0%	1.0025	19.0%
7	DTE Energy Co.	10.5%	1.0258	10.8%
8	Duke Energy Corp.	8.5%	1.0090	8.6%
9	Emera Inc.	13.0%	1.0183	13.2%
10	Eversource Energy	10.0%	1.0193	10.2%
11	Fortis, Inc.	8.0%	1.0273	8.2%
12	NextEra Energy, Inc.	14.0%	1.0349	14.5%
13	PPL Corp.	13.5%	1.0352	14.0%
14	Pub Sv Enterprise Grp.	11.0%	1.0175	11.2%
15	SCANA Corp.	11.0%	1.0013	11.0%
16	Sempra Energy	13.0%	1.0057	13.1%
17	Southern Company	12.5%	1.0146	12.7%
18	Vectren Corp.	12.0%	1.0119	12.1%
	Average (d)			**11.8%**
	Average-Woolridge Group (d,e)			**11.9%**
	Average-Baudino Group (d,f)			**11.9%**

(a) The Value Line Investment Survey (Jul. 28, Aug. 18 & Sep. 15, 2017).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) (a) x (b).
(d) Excluding highlighted values.
(e) Excluding Emera and Fortis.
(f) Excluding AVANGRID, Emera, and Fortis.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets Or Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)	Case No. 2017-00179

TESTIMONY OF

MATTHEW J. SATTERWHITE

ON BEHALF OF KENTUCKY POWER COMPANY

IN SUPPORT OF THE SETTLEMENT AGREEMENT

**SETTLEMENT TESTIMONY OF
MATTHEW J. SATTERWHITE, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

CASE NO. 2017-00179

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**SETTLEMENT TESTIMONY OF
MATTHEW J. SATTERWHITE, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND POSITION WITH KENTUCKY POWER COMPANY.

A. My name is Matthew J. Satterwhite, and I am the President and Chief Operating Officer of Kentucky Power Company ("Kentucky Power" or "Company").

Q. DID YOU FILE TESTIMONY IN THIS RATE PROCEEDING?

A. Yes. I filed both direct testimony and rebuttal testimony.

Q ARE YOU FAMILIAR WITH THE ISSUES PRESENTED IN THIS CASE BY THE COMPANY AND THE OTHER PARTIES GRANTED INTERVENTION?

A. Yes.

Q. DID YOU PARTICIPATE IN THE NEGOTIATIONS WHICH LED TO THE SETTLEMENT AGREEMENT BEING SUBMITTED FOR CONSIDERATION AND APPROVAL BY THE COMMISSION?

A. Yes. I participated in an initial informal meeting on October 24, 2017 at the Company's office in Frankfort with the parties to the case and informal conferences on October 26, 2017 and November 7, 2017 at the Commission that led to the agreement in principle. The Settlement Agreement is attached as **EXHIBIT MJS-S1**.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In my testimony I explain and support the terms of the Settlement Agreement, as well as demonstrating why the terms of the Settlement Agreement will produce fair, just, and reasonable rates. The underlying support for the issues in the case-in-chief is still sponsored by the Company witnesses sponsoring those issues. My testimony explains the deviation from the Company's filed case and summarizes the settlement process leading to those changes.

II. THE SETTLEMENT AGREEMENT

Q. PLEASE DESCRIBE GENERALLY THE AREAS ADDRESSED BY THE SETTLEMENT AGREEMENT.

A. The comprehensive Settlement Agreement addresses a number of substantive areas that differ from the Company's June 28, 2017 application in this case ("June 2017 Application") as updated on August 8, 2017 to reflect the impact of June 2017 refinancing activities on the Company's application ("August 2017 Refinancing Update"). The Settlement Agreement only reflects changes to the June 2017 Application and the August 2017 Refinancing Update. Unless otherwise altered in the Settlement Agreement, the Signatory Parties agreed to the proposed rates and other changes to the Company's terms and conditions of providing service set forth in the June 2017 Application and the August 2017 Refinancing Update (Paragraph 1). For example, the parties agreed to the Company's 2017 Environmental Compliance Plan as filed.

The major terms of the Settlement Agreement are:

1. A net annual increase in the Company's retail revenues of $31,780,734 (Paragraph 2) which represents a decrease of $28,616,704 from the requested $60,397,438 set forth in the August 2017 Refinancing Update;

2. Establishment of deferral and recovery mechanisms for $50 million of Rockport Unit Power Agreement ("UPA") Expenses (Paragraph 3);

3. Changes to the proposed Tariff P.P.A. to recover 80% of the change in annual PJM OATT LSE expense as compared to the annual amount included in base rates and to include an offset for the difference in return on transmission system investment (Paragraph 4);

4. An agreement by the Company to not file a request to change the general base rates for rates to be effective until the first day of the January 2021 billing cycle in exchange for the other provisions outlined in the agreement (Paragraph 5);

5. An agreement to change the depreciation rates for Big Sandy Unit 1 to use the 20 year expected life of the unit and a further adjustment to depreciation rates for Big Sandy Unit 1 and the Mitchell Plant to remove terminal net salvage costs for the setting of rates at this time (Paragraph 7);

6. The establishment of a return on equity of 9.75% and an update to the Company's capitalization to reflect short term debt as 1% of the Company's total capital structure (Paragraph 8);

7. Amortization of the remaining deferred storm expense regulatory asset authorized in Case No. 2012-00445 and the deferred storm expense regulatory asset from Case No. 2016-00180 over a five-year period beginning with approval of the settlement agreement in this case at an annual amount of $2,092,867 (Paragraph 9);

8. Amendment to the proposed structure of the Kentucky economic development surcharge ("KEDS") to decrease the residential charge to $0.10 per month and increase the non-residential per meter charge to $1.00 per month and to adjust the matching contribution by the Company (Paragraph 10);

9. A commitment to work with Marathon Petroleum on a backup and maintenance service agreement or to seek a Commission ruling if an agreement cannot be reached (Paragraph 11);

10. Inclusion of the DSM-based School Energy Manager Program as a program for Commission approval in the 2018 and 2019 DSM program filings and the extension of Tariff K-12 School which will now include private schools (Paragraphs 12 and 13);

11. Acceptance of the bill formatting changes proposed by the Company and a commitment by the Company to conduct training sessions with representatives from municipal customers to discuss bill format and tools available to better understand bills (Paragraphs 14);

12. Approval of the Renewable Power Option Rider with amended language to allow customers with meters under the same parent company to aggregate for purposes of qualifying for Option B (Paragraph 15).

13. Increase in the Company's customer charge for Tariff R.S. to $14.00 per month (Paragraph 16(a));

14. Approval of certain other new tariffs set out in the Company's application, as well as modifications of the Company's existing tariffs (Paragraph 16(b)); and

15. Approval of a new unified pole attachment rate of $8.52 (Paragraph 16(c)).

I discuss each of these areas, and the pertinent terms, in more detail below. In addition, the Settlement Agreement contains standard terms regarding its operation, interpretation, and applicability. Chief among these is Paragraph 19, which stresses the importance of Commission approval of the Settlement Agreement in its entirety. The Parties understand that no agreement binds the Commission in its ultimate initial jurisdiction over a general rate case filed before it. However, the Settlement Agreement represents significant give and take among the Signatory Partie. Further, the Company believes many of the items agreed to involve commitments beyond the unilateral authority of a regulatory body to impose absent an agreement, such as the Company's commitment to a base rate case "stay out."

Q. BEFORE DISCUSSING THE SPECIFIC TERMS OF THE SETTLEMENT AGREEMENT, PLEASE IDENTIFY THE PARTIES TO THE AGREEMENT.

A. The settling parties in this case include: Kentucky Power, Kentucky Industrial Utility Customers, Inc. ("KIUC"), Kentucky School Boards Association, ("KSBA"), Kentucky League of Cities ("KLC"); Wal-Mart Stores East, LP and Sam's East, Inc. ("Wal-Mart"); and Kentucky Cable Telecommunications Association ("KCTA")[1] (collectively "Signatory Parties").

[1] Due to scheduling conflicts, the Settlement Agreement attached does not include an executed signature page from KCTA. Kentucky Power and KCTA have reached an agreement and the Company anticipates that KCTA will provide an executed signature page during the week of November 27, 2017. Kentucky Power will file a fully executed copy of the Settlement Agreement upon receiving the signature page from KCTA.

Q. ARE THERE OTHER PARTIES TO THIS PROCEEDING WHO ARE NOT SIGNATORIES TO THE SETTLEMENT AGREEMENT?

A. Yes. The Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, ("Attorney General") and Kentucky Commercial Utility Customers, Inc. ("KCUC") are not signatories to the Settlement Agreement.

Q. WERE ALL PARTIES TO THIS PROCEEDING OFFERED THE OPPORTUNITY TO PARTICIPATE IN THE NEGOTIATIONS THAT LED TO THE EXECUTION OF THE SETTLEMENT AGREEMENT?

A. Yes. Representatives of the Office of the Attorney General attended the informal meeting on October 24, 2017 and the October 26, 2017 informal conference at the Commission. They indicated they would not attend the November 7, 2017 informal conference because of a scheduling conflict. In an e-mail exchange with Commission Staff on November 7, 2017, that Staff shared with the parties attending the informal conference, the Attorney General's representatives further indicated the settlement conference should proceed as scheduled and not be rescheduled. Kentucky Power discussed settlement individually with representatives of the Attorney General and kept them abreast of the developments, provided the information exchanged at the November 7, 2017 informal conference, and repeatedly offered the Attorney General the opportunity to join the other parties or engage in further negotiation. Representatives of KCUC attended all three settlement conferences and the Signatory Parties provided copies of all term sheets to KCUC.

Q. DOES THE SETTLEMENT AGREEMENT REPRESENT THE COMPLETE SETTLEMENT IN THIS CASE?

A. Yes. There are no agreements or understandings regarding the Company's application that are not reflected in the Settlement Agreement. The agreements and terms in the Settlement Agreement represent the sum total of the give and take of the Signatory Parties. Further, there are no agreements nor understandings with non-signatory parties relating to the subject matter of the Company's application.

Q. IS THE COMMISSION STAFF A PARTY TO THE SETTLEMENT AGREEMENT?

A. No. Commission Staff attended two informal conferences but made clear that it could not be a party to any agreement, that it was not speaking for the Commission, and that its participation in no way would bind the Commission to the agreement.

Q. DID THE PARTIES TO THIS CASE ACTIVELY LITIGATE THIS MATTER?

A. Yes. In addition to the four sets of data requests propounded by the Commission Staff and answered by Kentucky Power, multiple rounds of data requests, consisting of 793 separate data requests, not including subparts, also were propounded by KIUC, the Attorney General, Wal-Mart, KCUC, KLC, KSBA, and KCTA and answered by the Company. Testimony was filed by witnesses for all intervenors, and discovery taken regarding certain of these witnesses' testimony by Commission Staff, the Attorney General, and Kentucky Power. The Company also filed rebuttal testimony. Thus, Kentucky Power and the parties were fully informed of each other's respective positions while engaging in settlement negotiations.

Q. WHAT WAS THE TONE OF THE NEGOTIATIONS?

A. Without discussing specific matters raised during the negotiations, as they are confidential, I would like to thank the parties who worked in a constructive manner. There is recognition that Kentucky Power is working to help rebuild Eastern Kentucky's economy and as part of that effort the Company has needs that must be addressed under the regulatory compact. Likewise, the Parties advocated for their clients and the affordability of bills for all customers as the region deals with the economic situation it is facing. The settlement is a reflection of that creative thinking to allow Kentucky Power to meet its obligation to provide reasonable service while limiting the impact of the rate adjustment on all customers. I am encouraged by the constructive approach to the negotiations to put Eastern Kentucky first and work to a mutually agreeable solution that will allow the focus to return to rebuilding the economy in the region.

III. <u>THE TERMS OF THE SETTLEMENT AGREEMENT</u>

Q. IN SEVERAL PLACES IN YOUR TESTIMONY BELOW YOU NOTE THAT THE SETTLEMENT AGREEMENT EMBODIES A POSITION ADVOCATED BY ONE OR MORE OF THE INTERVENORS. DOES THE INCORPORATION OF THE INTERVENOR POSITION IN THE SETTLEMENT AGREEMENT CONSTITUTE AN ENDORSEMENT BY THE COMPANY OF THAT POSITION IN ABSENCE OF THE SETTLEMENT AGREEMENT?

A. Absolutely not. Like any fair and reasonable settlement, the Settlement Agreement represents a compromise by all parties to the agreement of their positions in a fully-litigated case. In fact, Paragraph 24 recognizes that the agreement is not to be construed as an admission by any party to agreement. Likewise, the agreement provides that it is not to be read as incorporating fully the objectives of the parties to the agreement. The Settlement Agreement is a package that balances out the interests of the Signatory Parties to provide the Commission a unique option to rule upon the issues in this case.

A. Net Increase In Annual Revenues

Q. YOU INDICATED THAT THE NET EFFECT OF THE SETTLEMENT AGREEMENT ON THE COMPANY'S RETAIL RATES WAS AN ANNUAL INCREASE OF \$31.8 MILLION. HOW DOES THAT COMPARE TO THE REQUEST IN THIS CASE?

A. The net annual increase in the Company's retail revenues of \$31,780,734 is described in Paragraph 2 of the Settlement Agreement. The updated revenue requirement reflects a decrease of \$28,616,704 from the \$60,397,438 requested by Kentucky Power in the August 2017 Refinancing Update. To be clear, and except when I expressly state to the contrary, when I discuss the Company's revenue requirement I am referring to the amount requested in the August 2017 Refinancing Update.

Q. DOES THE SETTLEMENT AGREEMENT IDENTIFY THE DERIVATION OF THE \$28,616,704 REDUCTION IN REQUESTED ADDITIONAL REVENUE?

A. Yes. This is not a black box settlement. The drivers for the \$28.6 million decrease in the Company's requested additional annual revenue requirement reflect agreed upon adjustments that are itemized in Paragraph 2 of the Settlement Agreement.

Q. DOES THE SETTLEMENT AGREEMENT EQUALIZE RATES OF RETURN ACROSS ALL CUSTOMER CLASSES?

A. No. It is unlikely that doing so could be accomplished in a single proceeding. That said, the Settlement Agreement reduces the inter-class subsidies to the residential class while limiting the effect of doing so on residential rates. The Signatory Parties used the decrease in the revenue requirement first to remove the subsidy provided to residential customers by industrial customers receiving service under Tariff I.G.S. The remainder of the rate reduction was then used to reduce the rate impact across the other classes. The result of the subsidy removal and decrease in the revenue requirement is a decrease across the board for all customer classes. The impact of the Settlement Agreement on revenue requirements by customer class is provided in **EXHIBIT 1** to the Settlement Agreement. Additional information about the allocation of the revenue requirement is included in the Settlement Testimony of Company Witness Vaughan.

B. Return On Equity

Q. DOES THE SETTLEMENT AGREEMENT SPECIFY A RETURN ON EQUITY?

A. Yes. The Signatory Parties agreed for settlement purposes that the Company shall be authorized a return on equity of 9.75%. The negotiated amount is below the 10.31% return justified in the testimony of Company Witness Adrien McKenzie. The only intervenors to file testimony regarding the Company's proposed rate of return were the Attorney General and KIUC. Attorney General Witness Woolridge proposed a return on equity of 8.60% while KIUC Witness Baudino proposed a rate of 8.85%. The settlement negotiations led to a compromise of 9.75% ROE. The testimony of Company Witness McKenzie stresses the importance of a fair and reasonable return on equity for the health of the utility and to permit the Company to provide adequate service. A return on equity of 9.75% provides this fair and reasonable return in the overall context of this settlement.

C. **Rockport Deferral Mechanism**

Q. DID THE SIGNATORY PARTIES AND THE COMPANY AGREE ON A METHOD TO DEFER A PORTION OF THE ROCKPORT UPA EXPENSES?

A. Yes. The Company was able to work with the parties to manage the deferral of non-fuel, non-environmental Rockport UPA Expense in a manner that minimized the risk associated with deferrals described by Company Witness Wohnhas in his rebuttal testimony while still relieving the pressure of customer bills in the near term. The agreement reflects a deferral of fifty million dollars ($50 million) over five years and provides that the deferral will be established as a regulatory asset for later recovery ("Rockport Deferral Regulatory Asset"). The Rockport Deferral Regulatory Asset, plus a WACC carrying charge, will be recovered through the Company's Tariff P.P.A. over a five- year period starting in December 2022. The end of the deferral period, and the start of the five-year amortization period, coincide with the anticipated end of the Rockport UPA in December 2022.

Q. WHAT IS THE DEFERRAL SCHEDULE?

A. The Signatory Parties agreed on an initial deferral of $15 million a year for the first two years of the deferral period and then a step down in the deferral amount in the final three years of the five-year deferral period. In calendar years 2018 and 2019 the Company will defer $15 million each year. The settlement's annual revenue requirement reflects that $15 million decrease to base rates. In 2020, the deferral will step-down to $10 million. The $5 million difference between the initial $15 million deferral in each of the first two years, and upon which base rates are established, and the $10 million deferral in 2020 will be recovered through an offsetting increase in the amount recovered through Tariff

P.P.A. In calendar years 2021 and 2022 the deferral is reduced by an additional $5 million each year to an annual deferral of $5 million. This additional reduction in the deferral amount is recovered through with an incremental offsetting increase of $5 million to the annual amount to be recovered through Tariff P.P.A. In 2022, the amount recovered through Tariff P.P.A. will be prorated through December 8 – the termination date of Rockport UPA. Utilizing Tariff P.P.A. provides a mechanism to achieve the reduction in the deferral amount without changing base rates. A summary of the Rockport UPA Expense deferral timeline is provided below:

YEAR	CREDIT IN BASE RATES	DEFERRAL AMT	AMT RECOVERED VIA TARIFF PPA
2018	$15 million	$15 million	$0
2019	$15 million	$15 million	$0
2020	$15 million	$10 million	$5 million
2021	$15 million	$5 million	$10 million
2022	$15 million	$5 million	$10 million[2]

Q. WHAT HAPPENS TO THE REGULATORY ASSET AFTER THE FIVE YEARS?

A. The Signatory Parties agreed to start recovery of the regulatory asset beginning in December 2022. The regulatory asset will be amortized over five years starting in December 2022 through Tariff P.P.A. The Rockport Deferral Regulatory Asset will be subject to carrying charges based on a weighted average cost of capital ("WACC") of 9.11% until the Regulatory Asset is fully recovered. The Company estimates the regulatory asset will total approximately $59 million at the end of 2022. That amount will decrease over the five-year amortization period until fully collected.

[2] Will be prorated through December 8 – the termination date of the Rockport UPA.

Q. HOW IS THE ROCKPORT DEFERRAL IN THIS SETTLEMENT AGREEMENT BENEFICIAL FOR CUSTOMERS?

A. The Rockport UPA Expense deferral as structured in the Settlement Agreement provides a more affordable rate structure in the immediate future balanced by the need to avoid too heavy of a burden on customers in the later years when it will be recovered. The concept is similar to public comments shared in Hazard, Kentucky during the Commission's public meeting. Some of the commenters expressed an understanding that Kentucky Power needed a rate increase to adequately operate, but the individuals asked the Commission to look for a way to delay the impact of the request for just a few years while the region fights back against the economic downturn. The proposed Rockport UPA Expense deferral helps accomplish that request. Rates in the near term will be set at a lower level than otherwise would be required with the guarantee that those deferred amounts will be collected by the Company for carrying those costs over a number of years.

Q. WHAT IS THE SIGNIFICANCE OF THE FIVE YEAR DEFERRAL TERM PROVIDED BY THE SIGNATORY PARTIES?

A. The Rockport UPA expires in December 2022. While the decision on whether to extend or not extend the Rockport UPA is not an issue in this case and a matter to be decided at a later date, the potential for the end of that agreement and its accompanying expenses provided an opportunity to structure the adjustment to rates to take advantage of that potential reduction in purchase power costs. If the Company is not paying the expenses associated with the Rockport agreement beginning in December 2022 then there is an opportunity to begin recovery of the deferred amount at the same time as the other

Rockport UPA expenses fall off the customer bills. The ultimate decision on whether to extend or not extend the Rockport UPA will be made at another time, but the timelines in place today provided a convenient framework to propose the concept and focus on the impact on customer bills.

Q. WHY IS THE DEFERRAL AMOUNT SUBJECT TO A CARRYING CHARGE?

A. The Company will be incurring and paying the Rockport UPA expenses prior to their recovery and will be financing the associated under-recovery with a combination of debt and equity. Thus, applying a carrying charge at the Company's WACC, which represents Kentucky Power's financing costs, is appropriate. This is especially true in light of the magnitude of the under-recovery and the time frame for recovering the regulatory asset.

Q. WHAT IS THE ROCKPORT CREDIT AND OFFSET THAT IS INCLUDED IN THE DEFERRAL PLAN AGREED TO BY THE SIGNATORY PARTIES?

A. The Rockport Offset and Credit are described in Paragraph 3(f-h) of the Settlement Agreement. If Kentucky Power does not extend the Rockport agreement then it will begin to credit the Rockport Fixed Cost Savings through Tariff P.P.A. until new base rates are set. The credit will be offset, however, by the retention by Kentucky Power of that portion of the Rockport Fixed Cost Savings in 2023 necessary to allow the Company to earn its Commission-authorized return on equity if it should be earning below that level at that time ("Rockport Offset").

Q. HOW WILL THE ROCKPORT FIXED COSTS SAVINGS AND OFFSET BE APPLIED?

A. As outlined in Paragraph 3(h) of the Settlement Agreement, the Company will file an updated factor for Tariff P.P.A. for rates effective December 9, 2022 to reflect the impact of the Fixed Cost Saving and Estimated Rockport Offset. This will represent the sum of the fixed cost savings and the estimated offset related to the estimated level necessary to meet the return on equity component in 2023. By February 1, 2024 the Company will file a final accounting to wrap up this credit/offset in the Tariff P.P.A. for rates effective March 1, 2024. This update will serve as the final true-up to provide a credit back to customers for any amount of any over-collection from the offset or collect any further amount due to finalize the mechanism. That true-up will be applied over the three months of March, April and May of 2024.

D. <u>PJM OATT LSE Expense Recovery and General Rate Case Stay Out</u>

Q. WILL YOU PLEASE EXPLAIN THE SETTLEMENT AGREEMENT'S TREATMENT OF THE COMPANY'S PJM OATT LSE EXPENSE RECOVERY?

A. Yes. Kentucky Power will track, on a monthly basis via deferral accounting, the amount of OATT LSE charges and credits above or below the amount embedded in base rates as discussed in the testimony of Company Witness Vaughan. Kentucky Power will recover 80% of this annual over- or under-collection of PJM OATT LSE charges ("Annual PJM OATT LSE Recovery") through Tariff P.P.A. That means that the Company will absorb 20% of any annual under-collection through base rates of PJM OATT LSE charges.

Q. WHY DOES THE SETTLEMENT AGREEMENT SINGLE OUT THE COMPANY'S PJM OATT LSE CHARGES FOR THIS TREATMENT?

A. Kentucky Power has the ability to manage most of its expenses. By contrast, PJM OATT LSE expenses are largely outside the Company's control and are volatile within the regulatory compact and test year construct. Coupled with the magnitude of the expected increases in the Company's PJM OATT LSE expenses – Kentucky Power forecasts that its PJM OATT LSE expenses will increase by $17 million or approximately 23% in 2018 over the test year amount – the Company would be forced to file another base rate case early in 2018 without the recovery mechanism provided in the Settlement Agreement.

Q. WHAT IS THE TRANSMISSION RETURN DIFFERENCE THE SETTLEMENT AGREEMENT PROVIDES AS AN OFFSET TO THE PJM OATT LSE EXPENSE?

A. Kentucky Power agreed to credit the difference in the return it receives on transmission investment in excess of the investment level already included in the Company's retail rate base between the FERC-approved return on equity and the 9.75% return on equity agreed to by the parties to the Settlement Agreement. The calculation of that credit is shown in **EXHIBIT 3** to the Settlement Agreement and is described in detail in the Settlement Testimony of Company Witness Vaughan.

Q. WILL THE COMMISSION HAVE THE OPPORTUNITY TO REVIEW THE ANNUAL UPDATES TO TARIFF P.P.A. REFLECTING THE PJM OATT LSE RECOVERY AND OFFSET?

A. Yes. The Company will make Tariff P.P.A. filings quantifying and describing the amounts to be recovered and the offset. The first update will not occur until August 2018. That means the rate impact of the costs (or credits) tracked under this mechanism will not impact customer bills until the fourth quarter of 2018.

E. **<u>Rate Case Stay Out</u>**

Q. PLEASE DESCRIBE THE RATE CASE STAY OUT PROVISION IN THE SETTLEMENT AGREEMENT?

A. The parties agreed to balance the Company's recovery of the 80% of incremental PJM OATT LSE expenses and the Rockport Deferral Regulatory Asset with an agreement by the Company not to file for a general adjustment of base rates to be effective prior to cycle 1 of the January 2021 billing cycle. That is essentially a three-year stay out from changing base rates. This provision also serves to address the concerns raised by customers on the frequency of general rate cases. This stay out is a settlement term that can only be done under the structure of a settlement agreement like the one entered into in this proceeding. Chapter 278 of the Kentucky Revised Statutes and the Commission's regulations do not authorize the Commission to order a utility not to file a general rate case. The balance provided by the Settlement Agreement, and particularly the Company's ability to recover 80% of the amount by which its actual PJM OATT LSE expenses exceed the amounts embedded in base rates, provide the Company the ability to agree to such an extreme restriction. Without all of the considerations provided by the Settlement Agreement, Kentucky Power lacks that ability.

Q. ARE THERE ANY EXCEPTIONS TO THIS AGREEMENT TO STAY-OUT FROM IMPLEMENTING NEW GENERAL RATES?

A. There are emergency clauses tied to a major change in law or where required to address an emergency that could adversely impact Kentucky Power or its customers. These clauses are intended for emergency situations that would significantly change the operations of the Company. An example of a material change in law would be the deregulation of the electric market in Kentucky. Such a change would have a material impact on the operations of the Company and could require a new general rate structure.

Q. DOES THAT LIMIT THE COMMISSION'S AUTHORITY OVER THE COMPANY'S RATES UNTIL 2021?

A. No, the Commission retains its ultimate jurisdiction over rates. Rates could change for other reasons, but the Company is agreeing not to file a general rate case to change rates in that time period. The Commission is not giving up any of its authority as a result of the Settlement Agreement to change the Company's general rates in a base rate case. In addition, the Commission retains its full regulatory authority with respect to the Company's riders and surcharges. This provision of the Settlement Agreement is a commitment by the Company not to file an application for the general adjustment of its base rates that would be effective prior to the first cycle of the January 2021 billing cycle. Customer bills will still change as a result of changes in existing riders.

F. <u>Additional Settlement Terms</u>

Q. WHAT CHANGES WERE MADE TO DEPRECIATION RATES FOR BIG SANDY UNIT 1 AND THE MITCHELL PLANT IN THE SETTLEMENT AGREEMENT?

A. The Signatory Parties agreed to use the 20-year expected life of Big Sandy Unit 1 in calculating the related depreciation expense. The Signatory Parties also agreed to adjust its depreciation rates for Big Sandy Unit 1 and for the Mitchell Plant to remove terminal net salvage costs. Terminal net salvage, which is discussed in more detail in the direct and rebuttal testimony of Company Witness Cash, reflects the difference between salvage and removal cost upon retirement of a unit. The changes to the depreciation rates as a result of the updated anticipated retirement date of Big Sandy Unit 1 and the removal of terminal net salvage rates from the calculation of the Company's depreciation expense are found in **EXHIBIT 5** to the Settlement Agreement.

Q. WHAT OTHER FINANCIAL UPDATES THAT IMPACT RATES ARE INCLUDED IN THE SETTLEMENT AGREEMENT?

A. Paragraph 8 of the Settlement Agreement discusses a number of updates. The 9.75% ROE agreed to in this Settlement Agreement is also applicable to the calculation of the Company's Environmental Surcharge factor and the carrying charges for the Rockport Deferral and Decommissioning Rider regulatory assets. Kentucky Power also agreed to a capital structure that reflects one percent short term debt with a 1.25% annual interest rate for the short term debt. The change to short term debt resulted in a decrease of approximately $350,000 to the revenue requirement. Likewise, the Settlement Agreement reflects the calculations of the WACC and GRCF as shown on **EXHIBIT 6** to the Agreement.

Q. WHAT DOES THE SETTLEMENT AGREEMENT PROVIDE FOR IN CONNECTION WITH STORM DAMAGE EXPENSE AMORTIZATION?

A. The Signatory Parties agreed to amortize the remaining unamortized balance of its existing deferred storm expense regulatory asset, authorized in Case No. 2012-00445, over a period of five years beginning January 1, 2018. This is consistent with the recommendation of KIUC and has the effect of extending the previous amortization period and reducing the Company's annual storm damage amortization expense. The unamortized balance of the existing storm damage regulatory asset will total $4,377,336 on December 31, 2017 and will be amortized over five years at an annual amount of

$875,467. In addition, the Settlement Agreement provides for the amortization of the regulatory asset authorized in Case No. 2016-00180 over a period of 5 years beginning January 1, 2018 consistent with the testimony of Company Witness Wohnhas. The balance of the regulatory asset authorized in Case No. 2016-00180 totals $4,377,336 and will be amortized over five years at an annual amount of $875,467. The combined balance of the Kentucky Power's deferred storm expense regulatory assets (the remaining unamortized balance authorized in Case No. 2012-00445 and the amount authorized in Case No. 2016-00180) will total $10,464,336 on December 31, 2017 and will be amortized over five years at an annual amount of $2,092,867.

Q. DID THE SETTLEMENT AGREEMENT PROPOSE ANY CHANGES TO THE COMPANY'S INCENTIVE COMPENSATION PLAN?

A. Yes. The Settling Parties agreed to decrease the level of incentive compensation by $3.15 million in the revenue requirement. While the Company still supports the full recovery of its incentive compensation plan as an important part of attracting and retaining top talent, for purposes of settlement at this time in this case, the Company agreed to remove that amount from the revenue requirement.

Q. HOW DOES THE SETTLEMENT IMPACT THE PROPOSED CHANGES TO THE KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE (KEDS)?

A. The Signatory Parties supported the increase in the funding for economic development through an increase in the KEDS charge. The adjustment made to the Company's proposal was to change the responsibility for payment levels. Under the Settlement Agreement (Paragraph 10), residential customers will pay a fixed monthly charge of $0.10 instead of the proposed $0.25. This is a reduction from the current $0.15 monthly charge. To make up that difference, non-residential customers will pay an increased level of per meter charges. The non-residential customers will pay a monthly charge of $1.00 per meter as opposed to the $0.25 proposed by the Company. This decreases the charge to the residential class of customers while still allowing them to be involved in the partnership of rebuilding the economy. This allocation will produce slightly more funds to be used for the KEDS grants. Kentucky Power will continue to match dollar-for-dollar the funds provided by customers at the modified levels provided for by the Settlement Agreement.

Q. WHAT PROVISION IS INCLUDED IN THE AGREEMENT RELATED TO THE REQUEST ON BACKUP AND MAINTENANCE SERVICE OPTIONS BY THE COMPANY?

A. The Settlement Agreement includes a provision (Paragraph 11) that sets up a path for discussions between Marathon Petroleum LP and Kentucky Power. The settlement term provides for a discussion between the two entities and if an agreement cannot be within 120 days of Marathon providing a specific proposal, then the issue may be presented to the Commission for a decision.

Q. HOW DOES THE SETTLEMENT TREAT THE SCHOOL ENERGY MANAGER PROGRAM?

A. The Signatory Parties agreed that Kentucky Power would seek to include funding up to $200,000 for the School Energy Manager Program as part of its 2018 and 2019 DSM Program offerings. The parties recognize that the Commission is not bound to approve the School Energy Manager Program or its funding level, and that both will be addressed in a separate proceeding. However, Kentucky Power supports the program and believes that it provides a tool by which the region's schools – both public and private – can reduce that portion of their budgets devoted to electric energy costs. As the result, Kentucky Power committed to seek to fund that program up to $200,000 in 2018 and 2019 through the DSM factor. The Settlement Agreement also recognizes that the Commission is currently studying the costs and benefits associated with the Company's DSM programs and their future offerings.

Q. DOES THE SETTLEMENT EXTEND THE PILOT TARIFF K-12 SCHOOL?

A. Yes. The Settlement Agreement (Paragraph 13) removes the pilot designation on the tariff and provides for the general service to all K-12 schools, both public and private, in the Company's territory. Under the offering, eligible schools may elect to take service under rates designed to produce $500,000 less annually in the aggregate from the Tariff K-12 eligible customers than would be produced if those same customers took service under the Tariff L.G.S. proposed as part of this Settlement Agreement. Also, the agreement provides that the total annual revenues produced by both Tariff L.G.S. and Tariff K-12 under the new rates will equal the total revenues that would be produced if all customers taking service under the two tariffs were taking service under the new Tariff L.G.S.

Q. WHAT DOES THE SETTLEMENT CHANGE RELATED TO THE BILL FORMAT REQUEST IN THE COMPANY'S FILING?

A. The bill formatting changes proposed by the Company in Case No. 2017-00231 and consolidated in this case will be approved to the extent they are not already approved (Paragraph 14). Kentucky Power will also hold training sessions for representatives of the municipal customers to address concerns their understanding of consolidated bills and other bill items. The Company has already visited with the City of Paintsville since KLC filed testimony raising a concern with the city's understanding of Company bills. The Company customer service representative walked the Paintsville staff through an online tool that provides customers access to data underlying the bill and how to better understand what is provided. The Company appreciates the time the city personnel spent with its customer service representative to ensure we could meet the customer's expectations. In addition, the Settling Parties agreed that any charges under Rider R.P.O. will be identified as a separate line on the bills of customers taking advantage of Rider R.P.O.

Q. DID THE SIGNATORY PARTIES AGREE ON THE STRUCTURE INTRODUCED BY THE COMPANY ON THE RENEWABLE POWER OPTION RIDER?

A. Yes, with one modification (Paragraph 15). The Settlement Agreement allows customers seeking to receive service under Option B to aggregate accounts to reach the 1,000 kW of peak demand needed as long as there is a common ownership under a single parent company. A revised Rider R.P.O incorporating the updated language is included as **EXHIBIT 8** to the Settlement Agreement.

Q. WHAT OTHER CHANGES DID THE SETTLEMENT AGREEMENT MAKE TO THE REQUEST FILED BY THE COMPANY IN ITS APPLICATION?

A. The Settlement Agreement reflects a change in the requested residential service charge. The Company requested a residential service charge of $17.50 as explained in the direct testimony of Company Witness Vaughan. The Signatory Parties agreed to decrease that customer charge to a value of $14.00. The current charge was updated in the last

Company base case and raised $3.00 to the current level of $11.00. In that previous case the Commission cited the concept of gradualism in only raising the charge $3.00 to $11.00. The $3.00 increase in this case is consistent with that precedent by raising the charge only $3.00 and not the $6.50 requested by the Company.

Q. WHAT DOES THE SETTLEMENT AGREEMENT DO TO ASSIST THE ECONOMIC SITUATION FACING THE COAL INDUSTRY IN EASTERN KENTUCKY?

A. The Settlement Agreement proposes to extend the Coal Plus program that currently is set to expire at the end of 2017. Earlier this year the Commission approved an effort by Kentucky Power to remove barriers to the opening and re-opening of coal operations. The Commission approved Tariff C.S.-Coal, and the amendments to Tariff C.S. – I.R.P., as well as Tariff E.D.R. approved in Case No. 2017-00099, through December 31, 2017. The Settlement Agreement seeks to extend that framework for another year. There are customers already taking advantage of the Coal Plus program and others have expressed an interest. The rate allocation in this case is also a benefit for the large coal operations. Many of the coal operations are served under Tariff I.G.S. The allocation proposed by the Settlement Agreement limits the impact to this rate class by removing the subsidy it pays to support the residential class. This served to limit the impact on these companies and encourage more operations to open or expand to new business in Eastern Kentucky.

Q. WHAT DID THE SETTLEMENT AGREEMENT DO TO ADDRESS THE POLE ATTACHMENT CONCERNS RAISED IN THE RECORD?

A. The Settlement Agreement includes a provision that defines a unified pole attachment rate for all users under Tariff C.A.T.V. The pole attachment rate for all users under

Tariff C.A.T.V. shall be $8.52 instead of the $11.97 rate for two-user poles and $7.42 rate for three-user poles proposed by the Company in its filing in this case. The unified rate makes implementation of Tariff C.A.T.V. simpler for both the Company and operators and reflects a reasonable increase in pole costs in the twelve years since the Company's pole attachment rates were last updated.

IV. REASONABLENESS OF THE SETTLEMENT AGREEMENT AND THE PROPOSED RATES

Q. DOES THE SETTLEMENT AGREEMENT FAIRLY BALANCE THE INTERESTS OF THE COMPANY AND ITS CUSTOMERS?

A. Yes. The Settlement Agreement represents a fair and proper balance between Kentucky Power's right to a fair return on its investment and the requirement that customers be charged fair, just, and reasonable rates.

Q. WHAT IS THE BASIS FOR THAT CONCLUSION?

A. Kentucky Power has faced multiple financial challenges since its last base rate case. The Company sought to address these challenges over the longer-term through its economic development efforts. Those efforts already have borne fruit as evidenced by the economic development successes described by Company Witness Hall. The Company's economic development successes do not address, however, the Company's need for financial relief in the near term. The Settlement Agreement addresses this near term need while providing important benefits, such as the Rockport Deferral and the base case stay-out provision, to all customers. Further, the increase of $31,780,734 in the Company's revenue requirement represents approximately 53% of the Kentucky Power's request.

Q. DOES THE SETTLEMENT AGREEMENT PROVIDE FOR FAIR, JUST, AND REASONABLE RATES?

A. Yes. Rates and tariffs should be designed to reflect and capture the opportunity to earn revenues that will produce a fair return on equity for the Company without posing an unfair or unreasonable burden on the ratepayers. The terms of the Settlement Agreement accomplish these objectives by balancing the need to provide for the existence of the utility while addressing the affordability of the rate increase through deferrals. In particular, the actions agreed to by the Company in this case related to the agreement to stay out from filing a general rate case are actions only achievable through a settlement agreement. The revenue allocations, tariffs and charges, while not those originally proposed by the Company, reflect a fair and proper balancing of the interests of the affected customer classes.

Q. DO YOU HAVE A RECOMMENDATION FOR THE COMMISSION?

A. Yes. The Settlement Agreement should be approved by the Commission without modification. In addition, the Commission should establish rates and charges in conformity with the agreement.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

VERIFICATION

The undersigned, Matthew J. Satterwhite, being duly sworn, deposes and says he is the President and COO for Kentucky Power Company that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

Matthew J. Satterwhite

COMMONWEALTH OF KENTUCKY)
) 2017-00179
COUNTY OF BOYD)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Matthew J. Satterwhite, this 20 day of November 2017.

Trisha M. Young Blum
Notary Public

Notary ID Number: 530202

My Commission Expires: 3-18-19

TRISHA M. YOUNG
NOTARY ID 530202
COMMISSION EXPIRES 3-18-19

EXHIBIT MJS-1S

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets Or Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)	Case No. 2017-00179

SETTLEMENT AGREEMENT

This Settlement Agreement, made and entered into this 22[nd] day of November, 2017, by and among Kentucky Power Company ("Kentucky Power" or "Company"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Kentucky School Boards Association ("KSBA"); Kentucky League of Cities ("KLC"); Wal-Mart Stores East, LP and Sam's East, Inc. ("Wal-Mart"); and Kentucky Cable Telecommunications Association ("KCTA"); (collectively Kentucky Power, KIUC, KSBA, KLC, Wal-Mart, and KCTA, are "Signatory Parties").

RECITALS

1. On June 28, 2017 Kentucky Power filed an application pursuant to KRS 278.190, KRS 278.183, and the rules and regulations of the Public Service Commission of Kentucky ("Commission"), seeking an annual increase in retail electric rates and charges totaling $69,575,934, seeking approval of its 2017 Environmental Compliance Plan, an order approving accounting practices to establish regulatory assets or liabilities, and further seeking authority to implement or amend certain tariffs ("June 2017 Application").

2. On August 8, 2017, Kentucky Power supplemented its filing to reflect the impact of subsequent refinancing activities on the Company's Application ("August 2017 Refinancing Update"). The refinancing activities reduced the Company's requested annual increase in retail electric rates and charges from $69,575,934 to $60,397,438.

3. KIUC, KSBA, KLC, Wal-Mart, and KCTA filed motions for full intervention in Case No. 2017-00179. The Commission granted the intervention motions. Collectively KIUC, KSBA, KLC, Wal-Mart, and KCTA are referred to in this Settlement Agreement as the "Settling Intervenors."

4. The Attorney General of the Commonwealth of Kentucky ("Attorney General") and Kentucky Commercial Utility Customers, Inc. ("KCUC") also filed motions to intervene. The Attorney General and KCUC, who are not parties to this agreement, were granted leave to intervene.

5. Certain of the Settling Intervenors, KCUC, and the Attorney General filed written testimony in Case No. 2017-00179 raising issues regarding Kentucky Power's Rate Application.

6. Kentucky Power, KCUC, the Attorney General, and the Settling Intervenors have had a full opportunity for discovery, including the filing of written data requests and responses.

7. Kentucky Power offered the Settling Intervenors, KCUC, and the Attorney General, along with Commission Staff, the opportunity to meet and review the issues presented by Kentucky Power's application in this proceeding and for purposes of settlement.

8. The Signatory Parties execute this Settlement Agreement for purposes of submitting it to the Kentucky Public Service Commission for approval pursuant to KRS 278.190 and KRS 278.183 and for further approval by the Commission of the rate increase, rate structure, and tariffs as described herein.

9. The Signatory Parties believe that this Settlement Agreement provides for fair, just, and reasonable rates.

NOW, THEREFORE, for and in consideration of the mutual promises set forth above, and the agreements and covenants set forth herein, Kentucky Power and the Settling Intervenors hereby agree as follows:

AGREEMENT

1. Kentucky Power's Application

(a) Except as modified in this Settlement Agreement, Kentucky Power's June 2017 Application as updated by the August 2017 Refinancing Update is approved.

2. Revenue Requirement

(a) Effective for service rendered on or after January 19, 2018, Kentucky Power shall implement a base rate adjustment sufficient to generate additional annual retail revenues of $31,780,734. This annual retail revenue amount represents a $28,616,704 million reduction from the $60,397,438 sought in the Company's August 2017 Refinancing Update.

(b) The $28,616,704 million reduction was the result of the following adjustments to the Company's request in the June 2017 Rate Application as modified in the August 2017 Refinancing Update:

Adjustment	Reduction in Revenue Requirement ($Millions)
Defer a portion of Rockport UPA non-fuel, non-environmental expenses	15.0
Increase revenues to Apply Weather Normalization to Commercial Sales Net of Variable O&M	0.40
Reduce Incentive Compensation	3.15
Reduce Amortization Expense to Recalibrate Storm Damage Amortization	1.22

Reduce Depreciation Expense by Extending Service Life of BS1 to 20 years	2.84
Reduce Depreciation Expense by Removing Terminal Net Salvage for BSU1	0.37
Reduce Depreciation Expense by Removing Terminal Net Salvage for Mitchell	0.57
Increase Short Term Debt to 1% and Set Debt Rate at 1.25%	0.36
Change in Return on Equity from 10.31% to 9.75%	4.70
Total Adjustments	**28.6**

(c) Kentucky Power agrees to allocate the $31,780,734 in additional annual revenue as illustrated on **EXHIBIT 1.** The Company will design rates and tariffs consistent with this allocation of additional revenue.

(i) As part of the Commission's consideration of the reasonableness of this Settlement Agreement, the tariffs designed in accordance with this subparagraph shall be filed with the Commission and served on counsel for all parties to this case no later than December 1, 2017.

(ii) Within ten days of the entry of the Commission's Order approving without modification this Settlement Agreement and the rates thereunder, Kentucky Power shall file with the Commission signed copies of the tariffs in conformity with 807 KAR 5:011.

3. <u>Rockport UPA Expense Deferral</u>

(a) Kentucky Power is a party to a FERC-approved Unit Power Agreement with AEP Generating Company for capacity and energy produced at the Rockport Plant ("Rockport UPA"). The Rockport UPA expires on December 8, 2022.

(b) Kentucky Power will defer a total of $50 million in non-fuel, non-environmental Rockport UPA Expense for later recovery as follows:

(i) Kentucky Power will defer $15M annually of Rockport UPA Expense in 2018 and 2019 for later recovery.

(ii) Kentucky Power will defer $10M of Rockport UPA Expense in 2020 for later recovery.

(iii) Kentucky Power will defer $5M annually of Rockport UPA Expense in years 2021 and 2022 for later recovery.

(c) The Rockport UPA Expense of $50 million described in Paragraph 3(b) above will be deferred into a regulatory asset ("the Rockport Deferral Regulatory Asset") and will be subject to carrying charges based on a weighted average cost of capital ("WACC") of 9.11%[1] until the Regulatory Asset is fully recovered. From January 1, 2018 through December 8, 2022, the WACC will be applied to the monthly Rockport Deferral Regulatory Asset principal balance net of accumulated deferred income taxes ("ADIT"). From December 9, 2022 until the Rockport Deferral Regulatory Asset is fully recovered, the WACC will be applied to the monthly Rockport Deferral Regulatory Asset balance including deferred carrying charges net of ADIT. The Rockport Deferral Regulatory Asset shall be recovered on a levelized basis through the demand component of Tariff P.P.A. and amortized over five years beginning on December 9, 2022. Kentucky Power estimates that the regulatory asset balance will total approximately $59 million on December 8, 2022.

(d) Additional expenses reflecting the declining deferral amount in years 2020 through 2022 will be recovered through the demand component of Tariff P.P.A. as follows:

(i) Kentucky Power will recover $5 million through Tariff P.P.A. in 2020

(ii) Kentucky Power will recover $10 million through Tariff P.P.A. in 2021

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[1] 6.48% grossed up for applicable State and Federal taxes, uncollectible accounts expense, and the KPSC maintenance fee

(iii) Kentucky Power will recover $10 million through Tariff P.P.A. in 2022, prorated through December 8, 2022.

(e) The Signatory Parties acknowledge that the Company's decision whether to seek Commission approval to extend the Rockport UPA will be made at a later date. Whether or not the Company seeks to extend the Rockport UPA, beginning December 9, 2022, the Capacity Charge recovered through Tariff C.C., approved in Case No. 2004-00420, will end. Any final over- or under-recovery balance will be included in the subsequent calculation of the purchase power adjustment under Tariff P.P.A. In the event that Kentucky Power elects not to extend the Rockport UPA, it will experience a reduction in Rockport UPA fixed costs ("Rockport Fixed Costs Savings").

(f) If Kentucky Power elects not to extend the Rockport UPA, it will, beginning December 9, 2022, credit the Rockport Fixed Cost Savings through the demand component of Tariff P.P.A. until new base rates are set. However, for 2023 only, the Rockport Fixed Cost Savings credit will be offset by the amount, if any, necessary for the Company to earn its Kentucky Commission-authorized return on equity (ROE) for 2023 ("Rockport Offset"). An example of the calculation of the Rockport Offset is included as **EXHIBIT 2**.

(g) For the purposes of implementing the Rockport Fixed Costs Savings credit described in Paragraph 3(f) above, the following definitions apply:

(i) "Rockport Fixed Costs Savings" shall mean the annual amount of non-fuel, non-environmental Rockport UPA expense included in base rates for rates effective in November 2022.

(ii) "Estimated Rockport Offset" shall mean the amount of additional annual revenue the Company estimates would be necessary for it to earn the Commission-authorized

return on equity for 2023 considering the termination of the Rockport UPA and the Rockport Fixed Cost Savings.

(iii) "Actual Rockport Offset" shall mean the amount of additional annual revenue that would have been necessary for the Company to earn the Commission-authorized return on equity for 2023 considering the termination of the Rockport UPA and the Rockport Fixed Cost Savings. The Company shall calculate the Actual Rockport Offset using a comparison of the per books return on equity for 2023 to the Commission-approved return on equity. The Actual Rockport Offset cannot exceed the Rockport Fixed Costs Savings.

(iv) "Rockport Offset True-Up" shall mean the difference between the Estimated Rockport Offset and the Actual Rockport Offset.

(h) The Company shall implement the Rockport Fixed Costs Savings credit described in Paragraph 3(f) above as follows:

(i) By November 15, 2022, the Company shall file an updated purchase power adjustment factor under Tariff P.P.A. for rates effective December 9, 2022. This filing shall reflect the impact of the Rockport Fixed Cost Savings and the Estimated Rockport Offset on the purchase power adjustment factor. This filing shall also reflect the commencement of recovery of the Rockport Deferral Regulatory Asset.

(ii) The Company shall make its normal August 15, 2023 Tariff P.P.A. filing for rates effective in October 2023. The Rockport Fixed Cost Savings and the Estimated Rockport Offset will continue to be factored into the calculation of the purchase power adjustment factor through the end of 2023. Beginning in January 2024, the Estimated Rockport Offset will not be factored into the calculation of the purchase power adjustment factor.

(iii) By February 1, 2024, the Company shall file an updated purchase power adjustment factor under Tariff P.P.A. for rates effective March 1, 2024. This filing shall only reflect the impact of the Rockport Offset True-Up on the purchase power adjustment factor. The purchase power adjustment factor shall be established to recover or credit the Rockport Offset True-Up amount in three months.

(iv) Beginning with the August 15, 2024 Tariff P.P.A. filing, the Company will incorporate the Rockport Fixed Cost Savings in its annual calculation of the purchase power adjustment factor.

4. PJM OATT LSE Expense Recovery

(a) As described in the testimony of Company Witness Vaughan, Kentucky Power has included an adjusted test year amount of net PJM OATT LSE charges and credits in base rates. Kentucky Power will track, on a monthly basis, the amount of OATT LSE charges and credits above or below the base rate level using deferral accounting. Kentucky Power will recover and collect 80% of the annual over or under collection of PJM OATT LSE charges, as compared to the annual amount included in base rates, ("Annual PJM OATT LSE Recovery") through the operation of Tariff P.P.A.

(b) Kentucky Power will credit against the Annual PJM OATT LSE Recovery 100% of the difference between the return on its incremental transmission investments calculated using the FERC-approved PJM OATT return on equity and the return on its incremental transmission investments calculated using the 9.75% return on equity provided for in this settlement (the "Transmission Return Difference"). Kentucky Power shall calculate the Transmission Return Difference as shown in **EXHIBIT 3**.

(c) These changes to Tariff P.P.A. to allow for the Annual PJM OATT LSE Recovery will terminate on the effective date when base rates are reset in the next base rate proceeding unless otherwise specifically extended by the Commission. Nothing in this Paragraph 4(c) prohibits Kentucky Power or any other Signatory Party from taking any position regarding the extension of the Annual PJM OATT LSE Recovery mechanism or any other treatment of the Company's PJM OATT LSE expenses.

5. Rate Case Stay Out

(a) Kentucky Power will not file an application for a general adjustment of base rates for rates that would be effective prior to the first day of the January 2021 billing cycle. This rate case "stay out" is expressly conditioned on Commission approval of this Settlement Agreement without modification including the recovery of the Rockport Deferral Regulatory Asset as described in Section 3 above and the incremental PJM OATT LSE expense through Tariff P.P.A. as described in Section 4 above.

(b) This stay out will not apply if a change in law occurs that will result in a material adverse effect on the Company's financial condition.

(c) Nothing in this stay out provision should be interpreted as prohibiting the Commission from altering the Company's rates upon its own investigation, or upon complaint, including to reflect changes in the tax code, including the federal corporate income tax rate, depreciation provisions, or upon a request by the Company to seek leave to address an emergency that could adversely impact Kentucky Power or its customers. In the event the Commission initiates an investigation or a complaint is filed with the Commission regarding the Company's rates, the Company retains the right to defend the reasonableness of its rates in such proceedings.

6. Tariff P.P.A.

(a) Kentucky Power's proposed changes to Tariff P.P.A., as set forth in the testimony of Company Witness Vaughan and modified by Sections 2 and 3 above, are approved.

(b) A revised version of Tariff P.P.A. incorporating the modifications described in Sections 2 and 3 above is included as **EXHIBIT 4.**

7. Depreciation Rates

(a) Kentucky Power and the Settling Intervenors agree that Big Sandy Unit 1 has an expected life of 20 years following its conversion from a coal-fired to a natural gas-fired generating unit. The depreciation rates for Big Sandy Unit 1 have been adjusted to reflect the 20 year expected life. Kentucky Power and the Signatory Parties retain the right to propose updated depreciation rates for Big Sandy Unit 1 in future proceedings to reflect updates to the expected life.

(b) Kentucky Power has adjusted depreciation rates for Big Sandy Unit 1 and for the Mitchell Plant to remove terminal net salvage costs. Kentucky Power retains the right to propose updated depreciation rates for Big Sandy Unit 1 and for the Mitchell Plant in future proceedings to include terminal net salvage costs, and the Settling Intervenors retain the right to challenge the inclusion of such costs in future proceedings.

(c) Kentucky Power's updated depreciation rates are included as **EXHIBIT 5.**

8. Return on Equity, Capitalization, WACC, and GRCF

(a) Kentucky Power shall be authorized a 9.75% return on equity. The authorized return on equity of 9.75% will be used in the calculation of the Company's Environmental Surcharge factor (for non-Rockport environmental projects) and the carrying charges for the Rockport Deferral and Decommissioning Rider regulatory assets.

(b) Kentucky Power will update its capitalization to reflect short term debt as 1% of the Company's total capital structure. The annual interest rate for the short term debt will be set at 1.25%.

(c) Kentucky Power shall utilize a weighted average cost of capital ("WACC") of 9.11% including a gross revenue conversion factor ("GRCF") of 1.6433%. The GRCF does not include a Section 199 deduction. This WACC and GRCF shall remain constant (including for the riders and surcharges described in Paragraph 8(a) above) until such time as the Commission sets base rates in the Company's next base rate case proceeding. The calculations of the WACC and GRCF are shown on **EXHIBIT 6**.

9. Storm Damage Expense Amortization

(a) Kentucky Power will recover and amortize the remaining unamortized balance of its deferred storm expense regulatory asset authorized in Case No. 2012-00445 over a period of five years beginning January 1, 2018, consistent with the recommendation of KIUC. The unamortized balance of the regulatory asset authorized in Case No. 2012-00445 will total $6,087,000 on December 31, 2017 and will be amortized over five years at an annual amount of $1,217,400.

(b) Kentucky Power will recover and amortize the deferred storm expense regulatory asset authorized in Case No. 2016-00180 over a period of 5 years beginning January 1, 2018 consistent with the testimony of Company Witness Wohnhas. The balance of the regulatory asset authorized in Case No. 2016-00180 totals $4,377,336 and will be amortized over five years at an annual amount of $875,467.

(c) The combined balance of the Kentucky Power's deferred storm expense regulatory assets (the remaining unamortized balance authorized in Case No. 2012-00445 and the amount

authorized in Case No. 2016-00180) will total \$10,464,336 on December 31, 2017 and will be amortized over five years at an annual amount of \$2,092,867.

10. <u>Kentucky Economic Development Surcharge</u>

(a) Kentucky Power's new Kentucky Economic Development Surcharge Tariff ("Tariff K.E.D.S.") shall be approved with rates amended as follows:

(i) The KEDS rate for residential customers will be set at \$0.10 per meter instead of \$0.25 as proposed by the Company.

(ii) The KEDS rate for non-residential customers for which the KEDS applies will be set at \$1.00 per meter instead of \$0.25 as proposed by the Company.

(b) All KEDS funds collected by Kentucky Power shall be matched dollar-for-dollar by Kentucky Power from shareholder funds. The proceeds of KEDS and Kentucky Power's shareholder contribution shall be used by Kentucky Power for economic development projects, including the training of local economic development officials, in the Company's service territory. The KEDS, and the matching shareholder contribution, shall remain in effect until changed by order of the Commission.

(c) Kentucky Power will continue to file on or before March 31st of each year a report with the Commission describing: (i) the amount collected through the Economic Development Surcharge; and (ii) the matching amount contributed by Kentucky Power from shareholder funds. The annual report to be filed by the Company shall also describe the amount, recipients, and purposes of its expenditure of the funds collected through the Economic Development Surcharge and shareholder contribution.

(d) Kentucky Power shall serve a copy of the annual report to be filed with the Commission in accordance with subparagraph (c) on counsel for all parties to this proceeding.

11. Backup and Maintenance Service

(a) In order for Marathon Petroleum LP ("Marathon") to evaluate the economics of self or co-generation, Kentucky Power and Marathon will begin negotiations regarding the terms, conditions and pricing for backup and maintenance service within 30 days of a Commission Order approving this provision and will complete negotiations within the next 120 days. Prior to the start of the 120 day negotiation period, Marathon will provide Kentucky Power with specific information regarding the MW size of a potential self or co-generation facility and the type of generation technology being considered.

(b) If Kentucky Power and Marathon cannot reach an agreement on backup and maintenance service within 120 days, Kentucky Power and Marathon agree to submit the issue to the Commission for resolution.

12. School Energy Manager Program

(a) Kentucky Power shall seek leave from the Commission to include up to $200,000 for the School Energy Manager Program in its each of its 2018 and 2019 DSM Program offerings.

(b) Kentucky Power and KSBA both expressly acknowledge that there is in Case No. 2017-00097 a currently-pending Commission investigation of the Company's DSM programs and funding and that the outcome of that investigation could impact the School Energy Manager Program.

13. Tariff K-12 School

(a) Kentucky Power shall continue its current Pilot Tariff K-12 School but shall remove the Pilot designation as set forth in **Exhibit 7**. Tariff K-12 School shall be available for general service to all K-12 schools in the Company's service territory, public and private, with normal maximum demands greater than 100 kW. Tariff K-12 School shall reflect rates for

customers taking service under the tariff designed to produce annually in the aggregate $500,000 less from Tariff K-12 School customers than would be produced under the new L.G.S. rates to be established under this Settlement Agreement from customers eligible to take service under Tariff K-12 School. The aggregate total revenues to be produced by Tariff K-12 School and Tariff L.G.S. shall be equal to the revenues that would be produced in the aggregate by the new rates in the absence of Tariff K-12 School. Service under Tariff K-12 School shall be optional.

14. Bill Format Changes

(a) The bill formatting changes proposed by the Company in Case No. 2017-00231 and consolidated into this case by Commission Order dated July 17, 2017, to the extent not already approved, are approved.

(b) Within 180 days of a Commission Order approving this Settlement, Kentucky Power will conduct a training session with representatives from its municipal clients and KLC to explain the new bill format and tools available to clients to evaluate their electric usage.

15. Renewable Power Option Rider

(a) The proposed changes to the Company's Green Pricing Option Rider, including renaming the rider to the Renewable Power Option Rider ("Rider R.P.O."), are approved except that the availability of service provision for Option B will state the following:

> "Customers who wish to directly purchase the electrical output and all associated environmental attributes from a renewable energy generator may contract bilaterally with the Company under Option B. Option B is available to customers taking metered service under the Company's I.G.S., and C.S.-I.R.P. tariffs, or multiple L.G.S. tariff accounts with common ownership under a single parent company that can aggregate multiple accounts to exceed 1000 kW of peak demand."

A revised version of Rider R.P.O. incorporating the modifications described above is included as **EXHIBIT 8**. Bills for customers receiving service under Rider R.P.O. will include a separate line item for Rider R.P.O. charges.

(b) Beginning no later than March 31, 2018, and no later than each March 31 thereafter, Kentucky Power will file a report with the Commission describing the previous year's activity under Rider R.P.O. This annual report will replace the semi-annual reports filed in Case No. 2008-00151.

16. Modifications To Kentucky Power's Rate Tariffs

In addition to the rate and tariff changes described and agreed to above, Kentucky Power and the Settling Intervenors agree that the following tariffs shall be modified or implemented as described below:

(a) The Customer charge for the Residential Class ("Tariff R.S.") shall be increased to $14.00 per month instead of the $17.50 per month proposed by the Company in its filing in this case.

(b) The Company is extending the termination date for Tariff C.S. – Coal and the amendments to Tariff C.S. – I.R.P. and Tariff E.D.R. approved in Case No. 2017-00099 from December 31, 2017 to December 31, 2018.

(c) The pole attachment rate for all users under Tariff C.A.T.V. shall be $8.52 for all attachments instead of the $11.97 for attachments on two-user poles and $7.42 for attachments on three-user poles proposed by the Company in its filing in this case.

17. Filing Of Settlement Agreement With The Commission And Request For Approval

Following the execution of this Settlement Agreement, Kentucky Power and the Settling Intervenors shall file this Settlement Agreement with the Commission along with a joint request to the Commission for consideration and approval of this Settlement Agreement so that Kentucky Power may begin billing under the approved adjusted rates for service rendered on or before January 19, 2018.

18. Good Faith And Best Efforts To Seek Approval

(a) This Settlement Agreement is subject to approval by the Public Service Commission.

(b) Kentucky Power and the Settling Intervenors shall act in good faith and use their best efforts to recommend to the Commission that this Settlement Agreement be approved in its entirety and without modification and that the rates and charges set forth herein be implemented.

(c) Kentucky Power and the Settling Intervenors filed testimony in this case. Kentucky Power also filed testimony in support of the Settlement Agreement. For purposes of any hearing, the Settling Intervenors and Kentucky Power waive all cross-examination of the other Signatory Parties' witnesses except for purposes of supporting this Settlement Agreement unless the Commission disapproves this Settlement Agreement. Each further stipulates and recommends that the Notice of Intent, Application, testimony, pleadings, and responses to data requests filed in this proceeding be admitted into the record.

(d) The Signatory Parties further agree to support the reasonableness of this Settlement Agreement before the Commission, and to cause their counsel to do the same, including in connection with any appeal from the Commission's adoption or enforcement of this Settlement Agreement.

(e) No party to this Settlement Agreement shall challenge any Order of the Commission approving the Settlement Agreement in its entirety and without modification.

19. Failure Of Commission To Approve Settlement Agreement

If the Commission does not accept and approve this Stipulation in its entirety, then any adversely affected Party may withdraw from the Stipulation within the statutory periods provided for rehearing and appeal of the Commission's order by (1) giving notice of withdrawal to all other

Parties and (2) timely filing for rehearing or appeal. Upon the latter of (1) the expiration of the statutory periods provided for rehearing and appeal of the Commission's order and (2) the conclusion of all rehearing's and appeals, all Parties that have not withdrawn will continue to be bound by the terms of the Stipulation as modified by the Commission's order.

20. Continuing Commission Jurisdiction

This Settlement Agreement shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

21. Effect of Settlement Agreement

This Settlement Agreement shall inure to the benefit of, and be binding upon, the parties to this Settlement Agreement, their successors, and assigns.

22. Complete Agreement

This Settlement Agreement constitutes the complete agreement and understanding among the parties to this Settlement Agreement, and any and all oral statements, representations, or agreements. Any and all such oral statements, representations, or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into this Settlement Agreement.

23. Independent Analysis

The terms of this Settlement Agreement are based upon the independent analysis of the parties to this Settlement Agreement, are the product of compromise and negotiation, and reflect a fair, just, and reasonable resolution of the issues herein. Notwithstanding anything contained in this Settlement Agreement, Kentucky Power and the Settling Intervenors recognize and agree that the effects, if any, of any future events upon the income of Kentucky Power are unknown and this Settlement Agreement shall be implemented as written.

24. Settlement Agreement And Negotiations Are Not An Admission

(a) This Settlement Agreement shall not be deemed to constitute an admission by any party to this Settlement Agreement that any computation, formula, allegation, assertion, or contention made by any other party in these proceedings is true or valid. Nothing in this Settlement Agreement shall be used or construed for any purpose to imply, suggest or otherwise indicate that the results produced through the compromise reflected herein represent fully the objectives of the Signatory Parties.

(b) Neither the terms of this Settlement Agreement nor any statements made or matters raised during the settlement negotiations shall be admissible in any proceeding, or binding on any of the parties to this Settlement Agreement, or be construed against any of the parties to this Settlement Agreement, **except that** in the event of litigation or proceedings involving the approval, implementation or enforcement of this Agreement, the terms of this Settlement Agreement shall be admissible. This Settlement Agreement shall not have any precedential value in this or any other jurisdiction.

25. Consultation With Counsel

The parties to this Settlement Agreement warrant that they have informed, advised, and consulted with their respective counsel with regard to the contents and significance of this Settlement Agreement and are relying upon such advice in entering into this agreement.

26. Authority To Bind

Each of the signatories to this Settlement Agreement hereby warrant they are authorized to sign this agreement upon behalf of, and bind, their respective parties.

27. Construction Of Agreement

This Settlement Agreement is a product of negotiation among all parties to this Settlement Agreement, and no provision of this Settlement Agreement shall be construed in favor of or against any party hereto. This Settlement Agreement is submitted for purposes of this case only and is not to be deemed binding upon the parties hereto in any other proceeding, nor is it to be offered or relied upon in any other proceeding involving Kentucky Power or any other utility.

28. Counterparts

This Settlement Agreement may be executed in multiple counterparts.

29. Future Rate Proceedings

Nothing in this Settlement Agreement shall preclude, prevent, or prejudice any party to this Settlement Agreement from raising any argument or issue, or challenging any adjustment, in any future rate proceeding of Kentucky Power.

IN WITNESS WHEREOF, this Settlement Agreement has been agreed to as of this 22nd day of November 2017.

KENTUCKY POWER COMPANY

By: ______________________

Its: Counsel

KENTUCKY INDUSTRIAL UTILITY
CUSTOMERS, INC.

By: Michael Kurtz

Its: Counsel

KENTUCKY SCHOOL BOARDS
ASSOCIATION, INC.

By: Matthew Malone

Its: Legal Counsel

KENTUCKY LEAGUE OF CITIES

By: [signature]

Its: Director of Municipal Law & Training

KENTUCKY CABLE
TELECOMMUNICATION
ASSOCIATION, INC.

By: ______________________________

Its: ______________________________

WAL-MART STORES EAST, LP AND
SAM'S EAST, INC.

By: ______________________

Its: Counsel

CASE NO. 2017-00179
SETTLEMENT AGREEMENT
EXHIBIT LIST

1. Revenue Allocation
2. Rockport Offset Calculation
3. Transmission Return Difference Calculation
4. Revised Tariff P.P.A.
5. Depreciation Rates
6. Calculation of WACC and GRCF
7. Revised Tariff K-12 School
8. Revised R.P.O. Rider

EXHIBIT 1

Kentucky Power Company
Settlement Agreement Exhibit-1
Case No. 2017-00179
Settlement Revenue Allocation

Customer Class	Base Rate Case Settlement Increase							Increase Incorporating Surcharge Changes			Return on Rate Base		Settlement
		Settlement Base Rate Increase	ECP	HEAP KEDS	Total Increase	Test Year Rev	% Increase	Carrying Charge Savings in ES	Net Increase	Total Bill % Increase	Current ROR	Proposed ROR	Proposed Non-Fuel Base Revenue Increase
		a	b	c	d = a+b+c	e	= d/e	f	g = d+f	= g/e			
RS	$	20,076,436	$1,734,600	594	21,811,630	$232,952,481	9.36%	($835,019)	$20,976,611	**9.00%**	1.90%	3.77%	14.15%
SGS	$	984,981	$184,183	247,506	1,416,670	$21,371,729	6.63%	($88,664)	$1,328,006	**6.21%**	11.30%	12.90%	7.19%
MGS	$	3,421,623	$500,403	69,324	3,991,350	$60,245,787	6.63%	($240,889)	$3,750,461	**6.23%**	9.14%	10.96%	9.24%
GS*	$	4,406,604	$ 684,586	$ 316,830	$ 5,408,020	$ 81,617,516	6.63%	($329,553)	$5,078,467	**6.22%**	9.67%	11.43%	8.68%
LGS/PS	$	3,520,149	$549,861	8,467	4,078,477	$70,567,216	5.78%	($264,698)	$3,813,779	**5.40%**	8.78%	10.46%	8.61%
IGS	$	3,534,466	$836,950	694	4,372,110	$157,911,866	2.77%	($402,899)	$3,969,211	**2.51%**	6.82%	7.71%	5.85%
MW	$	4,956	$1,620	102	6,678	$221,405	3.02%	($780)	$5,898	**2.66%**	12.12%	13.02%	3.94%
OL	$	201,254	$82,080	0	283,334	$8,984,564	3.15%	($39,512)	$243,822	**2.71%**	15.03%	15.68%	2.87%
SL	$	36,869	$13,751	0	50,620	$1,645,931	3.08%	($6,620)	$44,000	**2.67%**	15.92%	16.84%	3.29%
Total	$	31,780,734	$ 3,903,448	$ 326,687	$ 36,010,869	$ 553,900,979	6.50%	($1,879,080)	$34,131,789	**6.16%**	4.85%	6.48%	9.47%

* GS is the combination of the SGS and MGS classes

EXHIBIT 2

Kentucky Power Company
Exhibit 2 - Rockport Offset Calculation Example
Case No. 2017-00179

	*Calculation**			*Source*
a	12 Month GAAP Net Income	$	97,000,000	Q4 2023 Per Books as Reported SEC Kentucky Power Company
b	13 Month Average Common Equity	$	1,000,000,000	Q4 2023 Per Books as Reported SEC Kentucky Power Company
c = a/b	Return on Common Equity		9.70%	Calculation
d	Kentucky Power Allowed Retail ROE		9.75% **	Commission Order
	If D < C, Stop If D > C, Continue to Part e			
e = (b*d)-a	Net GAAP Income Increase Required to Earn Allowed Retail ROE	$	500,000	Calculation
f	Gross Revenue Conversion Factor		1.6433 **	Commission Order
g = e*f	Rockport Earnings Retainer Revenue	$	821,670	Calculation
= g	***Amount to Be Recovered Through Tariff PPA***	***$***	***821,670***	

*These numbers are illustrative
** Or as updated in a future Commission proceeding

EXHIBIT 3

Kentucky Power Company
Settlement Exhibit 3 - Transmission Return Difference Calculation
Case No. 2017-00179

	Calculation*			***Source***	***Frequency***
a	TO Transmission Rate Base	$	319,471,085	2018 OATT TCOS	Update Annually
b	KY Juris Retail Demand Factor		0.985	2017-00179 Section V, Allocation Factors	Remains Static
c = a*b	KY Retail TO Trans Rate Base	$	314,679,018	calculation	
d	Base Rate KY Retail Trans Rate Base	$	266,193,980	2017-00179 Class Cost of Service	Remains Static
e = c-d	Difference	$	48,485,038	calculation	
f	TO WACC @ 11.49 ROE		7.55%	2018 OATT TCOS	Update Annually
g	TO WACC @ 9.75 ROE		6.78%	2018 OATT TCOS	Update Annually
h = f-g	Difference		0.77%	calculation	
j = e*h	TO Return Delta	$	371,431	calculation	
k	GRCF		1.6351	2018 OATT TCOS	Update Annually
= j*k	***2018 Tariff PPA Revenue Credit***	***$***	***607,326***	calculation	Update Annually

*These numbers are illustrative

EXHIBIT 4

KENTUCKY POWER COMPANY P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 35-1
CANCELLING P.S.C. KY. NO. 11 ________ SHEET NO. 35-1

TARIFF P.P.A.
(Purchase Power Adjustment) T

APPLICABLE.

To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., K-12 School, L.G.S., L.G.S.-T.O.D., I.G.S., C.S. – I.R.P., M.W., O.L. and S.L.

RATE.

The annual purchase power adjustment factor will be computed using the following formula:

1. Annual Purchase Power Net Costs (PPANC)

   PPANC = N+RP+CSIRP+G+OATT+RKP-BPP

   Where:

   BPP = The annual amount of purchase power costs included in base rates, $78,737,938.

   a. N = The annual cost of power purchased by the Company through new Purchase Power Agreements. All new purchase power agreements shall be approved by the Commission to the extent required by KRS 278.300.
   b. RP = The annual purchased power costs not otherwise recoverable in the Fuel Adjustment Clause including but not limited to the cost of fuel related substitute generation less the cost of fuel which would have been used in plants suffering forced generation or transmission outages and the cost of purchases in excess of the highest cost owned or leased unit.
   c. CSIRP = The net annual cost of any credits provided to customers under Tariff C.S.-I.R.P. for interruptible service.
   d. G = The annual gains and losses on incidental gas sales; and
   e. OATT = 80% The net annual PJM load-serving entity Open Access Transmission Tariff Charges above or below the $74,038,517 included in BPP, less the transmission return difference pursuant to the Commission approved Settlement agreement in Case No. 2017-00179.
   f. RKP = Rockport related items includable in Tariff PPA pursuant to the Commission approved Settlement agreement in Case No. 2017-00179:
      i. Increase in Rockport collection resulting from reduction in base rate deferral;
      ii. Rockport deferral amount to be recovered;
      iii. Rockport fixed cost savings; and T
      iv. Rockport offset estimate and true-up.
      v. Final (over)/under recovery associated with tariff CC following its expiration

(Cont'd on Sheet No. 35-2)

DATE OF ISSUE:

DATE EFFECTIVE: Service Rendered On And After January 19, 2018

ISSUED BY: Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated XXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 35-2**
CANCELLING P.S.C. KY. NO. 11 _________ SHEET NO. 35-2

TARIFF P.P.A. (Cont'd)
(Purchase Power Adjustment)

N

RATES.

Tariff Class	\$/kWh	\$/kW
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.	\$0.00000	--
S.G.S.-T.O.D.	\$0.00000	--
M.G.S.-T.O.D.	\$0.00000	--
G.S.	\$0.00000	--
L.G.S., P.S, L.G.S.-T.O.D.	\$0.00000	\$0.00
L.G.S.-L.M.-T.O.D.	\$0.00000	--
I.G.S. and C.S.-I.R.P.	\$0.00000	\$0.00
M.W.	\$0.00000	--
O.L.	\$0.00000	--
S.L.	\$0.00000	--

The kWh factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW factor as calculated above will be applied to all on-peak and minimum billing demand kW for the LGS and IGS tariff classes.

The Purchase Power Adjustment factors shall be modified annually using the following formula:

The Purchase Power Adjustment factors shall be determined as follows:
For all tariff classes without demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total}) + PPA(D) \times (CP_{Class} / CP_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = 0$$

For all tariff classes with demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = \frac{PPA(D) \times (CP_{Class} / CP_{Total})}{BD_{Class}}$$

N

(Cont'd on Sheet No. 35-3)

DATE OF ISSUE:

DATE EFFECTIVE: Service Rendered On And After January 19, 2018

ISSUED BY: Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated XXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 35-3**
CANCELLING P.S.C. KY. NO. 11 ________ SHEET NO. 35-3

TARIFF P.P.A. (Cont'd)
(Purchase Power Adjustment)

N

RATES. (Cont'd)

Where:

1. "PPA(D)" is the actual annual retail PPA demand-related costs, plus any prior review period (over)/under recovery.

2. "PPA(E) is the actual annual retail PPA energy-related costs, plus any prior review period (over)/under recovery.

3. "BE_{Class}" is the historic annual retail jurisdictional billing kWh for each tariff class for the current year.

4. "BD_{Class}" is the historic annual retail jurisdictional billing kW for each applicable tariff class for the current year.

5. "CP_{Class}" is the coincident peak demand for each tariff class estimated as follows:

Tariff Class	BE_{Class}	CP/kWh Ratio	CP_{Class}
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.		0.0240909%	
S.G.S.-T.O.D.		0.0196553%	
M.G.S.-T.O.D.		0.0196553%	
G.S.		0.0196553%	
L.G.S., P.S, L.G.S.-T.O.D		0.0170480%	
L.G.S.-L.M.-T.O.D.		0.0170480%	
I.G.S. and C.S.-I.R.P.		0.0118222%	
M.W.		0.0135480%	
O.L.		0.0000000%	
S.L.		0.0000000%	

6. "BE_{Total}" is the sum of the BE_{Class} for all tariff classes.

7. "CP_{Total}" is the sum of the CP_{Class} for all tariff classes.

8. The factors as computed above are calculated to allow the recovery of Uncollectible Accounts Expense of 0.34% and the KPSC Maintenance Fee of 0.1996% and other similar revenue based taxes or assessments occasioned by the Purchase Power Adjustment revenues.

9. The annual PPA factors shall be filed with the Commission by August 15 of each year with the exception of the Rockport items includable in Tariff PPA pursuant to the Commission approved Settlement agreement in Case No. 2017-00179, with rates to begin with the October billing period, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

   Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884. N

DATE OF ISSUE:

DATE EFFECTIVE: Service Rendered On And After January 19, 2018

ISSUED BY: Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated XXXXXXX

EXHIBIT 5

Exhibit 5 - Depreciation Rates
Case No. 2017-00179

KENTUCKY POWER COMPANY
BIG SANDY UNIT 1 AND MITCHELL PLANT SETTLEMENT DEPRECIATION RATES CALCULATION
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2013 (MITCHELL) AND AT DECEMBER 31, 2016 (BIG SANDY UNIT 1)
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

Acct.	Title	Original Cost	Net Salvg. Ratio	Total to be Recovered	Calculated Depreciation Requirement	Accumulated Depreciation	Remaining to Be Recovered	Avg. Remain Life	Annual Accrual Amount	Annual Accrual Percent
(I)	(II)	(III)	(IV)	(V)	(VI)	(VII)	(VIII)	(IX)	(X)	(XI)
STEAM PRODUCTION PLANT										
Big Sandy Unit 1										
311.0	Structures & Improvements	11,756,127	1.02	11,991,250	7,526,502	4,805,397	7,185,853	20.00	359,293	3.06%
312.0	Boiler Plant Equipment	75,388,722	1.02	76,896,496	22,552,265	9,774,280	67,122,216	20.00	3,356,111	4.45%
314.0	Turbogenerator Units	61,392,346	1.02	62,620,193	36,338,075	28,424,981	34,195,212	20.00	1,709,761	2.78%
315.0	Accessory Electrical Equip.	3,877,136	1.02	3,954,679	2,964,549	2,578,951	1,375,728	20.00	68,786	1.77%
316.0	Misc. Power Plant Equip.	3,321,344	1.02	3,387,771	2,153,127	1,512,867	1,874,904	20.00	93,745	2.82%
	Total	155,735,675		**158,850,389**	**71,534,518**	**47,096,476**	**111,753,913**		**5,587,696**	**3.59%**
Mitchell Plant										
311	Structures & Improvements	42,000,197	1.03	43,260,203	18,282,178	16,183,402	27,076,801	25.01	1,082,639	2.58%
312	Boiler Plant Equipment	765,644,984	1.03	788,614,334	245,324,500	238,518,432	550,095,902	24.25	22,684,367	2.96%
312	Boiler Plant Equip SCR Catalyst	8,190,115	1.00	8,190,115	4,023,394	2,378,493	5,811,622	4.07	1,023,764	12.50%
314	Turbogenerator Units	53,295,697	1.03	54,894,568	29,106,660	33,613,523	21,281,045	23.84	892,661	1.67%
315	Accessory Electrical Equip.	17,080,672	1.03	17,593,092	9,466,086	11,043,285	6,549,807	25.81	253,770	1.49%
316	Misc. Power Plant Equip.	7,693,412	1.03	7,924,214	3,289,590	3,072,520	4,851,694	23.96	202,491	2.63%
	Total	893,905,077	1.03	920,476,526	309,492,408	304,809,655	**615,666,871**	23.55	**26,139,693**	2.92%

Notes:
1.) Terminal net salvage removed as a component of net salvage ratio for both plants (column IV).
2.) Average remaining life adjusted to reflect a 20 year useful life of BS1 (column IX).
3.) Mitchell Plant information from schedule used to calculate depreciation rates in settlement of Case No. 2014-00396.

EXHIBIT 6

Kentucky Power Company
Exhibit 6a - Calculation of Weighted Average Cost of Capital
Case No. 2017-00179

KENTUCKY POWER COMPANY
COST OF CAPITAL
TEST YEAR ENDED FEBRUARY 28, 2017

Line No.	Description	Reapportioned Kentucky Jurisdictional Capital 1/	Percentage of Total	Annual Cost Percentage Rate		Weighted Average Cost Percent	Gross Up	Pre-Tax Weighted Average Cost Percent
(1)	(2)	(3)	(4)	(5)		(6) = (4) X (5)	(7)	(8) = (6) X (7)
1	Long Term Debt	$636,995,903	53.45%	4.36%	2/	2.33%	1.00540	2.34%
2	Short Term Debt	11,917,855	1.00%	1.25%	3/	0.01%	1.00540	0.01%
3	Accounts Receivable F	46,105,009	3.87%	1.95%	5/	0.08%	1.00540	0.08%
4	Common Equity	496,766,726	41.68%	**9.75%**	6/	4.06%	1.64334	6.67%
5	Total	$1,191,785,493	100.00%			**6.48%**		**9.11%**

Kentucky Power Company
Exhibit 6b - Calculation of Gross Revenue Conversion Factor
Case No. 2017-00179

KENTUCKY POWER COMPANY
COMPUTATION OF THE GROSS REVENUE
CONVERSION FACTOR
TEST YEAR ENDED FEBRUARY 28,2017

Line No. (1)	Description (2)		Percent of Incremental Gross Revenues (3)
1	Operating Revenues		100.00%
2	Less: Uncollectible Accounts Expense 1/		0.3400%
3	KPSC Maintenance Fee		0.1996%
4	Income Before income Taxes		99.4604%
5	Less: State Income Taxes (L4 X 5.8742%) 2/	5.87%	5.843%
6	Income Before Federal Income Taxes		93.6179%
7	Less: Federal income Taxes (L6 X 35.00%)	35.00%	32.7663%
8	Operating Income Percentage		60.8516%
9	Gross Revenue Conversion Factor (100% / L8)		**1.6433**

EXHIBIT 7

KENTUCKY POWER COMPANY — P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 9-9
CANCELLING P.S.C. KY. NO. 11 ________ SHEET NO. 9-9

TARIFF K-12 SCHOOL
(Public and Private School)

AVAILABILITY OF SERVICE.

Available for general service to K-12 School customers subject to KRS 160.325 with normal maximum demands greater than 100 KW but not more than 1,000 KW.

RATE.

	Service Voltage			
	Secondary	Primary	Subtransmission	Transmission
Tariff Code	260	264	268	270
Service Charge per Month	$ 85.00	$ 127.50	$ 660.00	$ 660.00
Demand Charge per KW	$ 7.97	$ 7.18	$ 5.74	$ 5.60
Excess Reactive Charge per KVA	$ 3.46	$ 3.46	$ 3.46	$ 3.46
Energy Charge per KWH	7.671¢	6.709¢	5.535¢	5.429¢

MINIMUM CHARGE.

Bills computed under the above rate are subject to a monthly minimum charge comprised of the sum of the service charge and the minimum demand charge. The minimum demand charge is the product of the demand charge per KW and the monthly billing demand.

ADJUSTMENT CLAUSES.

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 5
System Sales Clause	Sheet No. 19
Franchise Tariff	Sheet No. 20
Demand-Side Management Adjustment Clause	Sheet No. 22
Kentucky Economic Development Surcharge	Sheet No. 24
Capacity Charge	Sheet No. 28
Environmental Surcharge	Sheet No. 29
School Tax	Sheet No. 33
Purchase Power Adjustment	Sheet No. 35
Decommissioning Rider	Sheet No. 38

(Cont'd on Sheet No. 9-10)

DATE OF ISSUE:

DATE EFFECTIVE: Service Rendered On And After January 19, 2018

ISSUED BY: Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated XXXXXXX

TARIFF K-12 SCHOOL (Cont'd)
(Public and Private School)

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

(1) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.

(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

MONTHLY BILLING DEMAND.

Billing demand in KW shall be taken each month as the highest 15-minute integrated peak in kilowatts as registered during the month by a 15-minute integrating demand meter or indicator, or at the Company's option as the highest registration of a thermal type demand meter or indicator. The monthly billing demand so established shall in no event be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

DETERMINATION OF EXCESS KILOVOLT-AMPERE (KVA) DEMAND.

The maximum KVA demand shall be determined by the use of a multiplier equal to the reciprocal of the average power factor recorded during the billing month, leading or lagging, applied to the metered demand. The excess KVA demand, if any, shall be the amount by which the maximum KVA demand established during the billing period exceeds 115% of the kilowatts of metered demand.

(Cont'd on Sheet No. 9-11)

TARIFF K-12 SCHOOL (Cont'd)
(Public and Private School)

TERM OF CONTRACT.

Contracts under this tariff will be made for customers requiring a normal maximum monthly demand between 500 KW and 1,000 KW and be made for an initial period of not less than 1 (one) year and shall remain in effect thereafter until either party shall give at least 6 months written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts or periods greater than 1 (one) year. For customers with demands less than 500 KW, a contract may, at the Company's option, be required.

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods greater than one year for all customers served under this tariff.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

CONTRACT CAPACITY.

The Customer shall set forth the amount of capacity contracted for (the "contract capacity") in an amount up to 1,000 KW. Contracts will be made in multiples of 25 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to Customers having other sources of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the customer shall contract for the maximum amount of demand in KW, which the Company might be required to furnish, but not less than 100 KW nor more than 1,000 KW. The Company shall not be obligated to supply demands in excess of the contract capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billings periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or II or by special agreement with the Company.

EXHIBIT 8

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 31-1**
CANCELLING P.S.C. KY. NO. 11 ________ SHEET NO. 31-1

RIDER R.P.O.
(Renewable Power Option Rider)

AVAILABILITY OF SERVICE.

Available to customers taking metered service under the Company's R.S., R.S.D. , R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., K-12 School, L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P. and M.W. tariffs. T T

Participation in this program under Option A may be limited by the ability of the Company to procure renewable energy certificates (RECs) from Renewable Resources. If the total of all kWh under contract under this Rider equals or exceeds the Company's ability to procure RECs, the Company may suspend the availability of this Rider to new participants. T

Customers who wish to directly purchase the electrical output and all associated environmental attributes from a renewable energy generator may contract bilaterally with the Company under Option B. Option B is available to customers taking metered service under the Company's I.G.S., and C.S.-I.R.P. tariffs, or multiple L.G.S. tariff accounts with common ownership under a single parent company that can aggregate multiple accounts to exceed 1000 kW of peak demand. N N

CONDITIONS OF SERVICE.

Customers who wish to support the development of electricity generated by Renewable Resources may under Option A contract to purchase each month a specific number of fixed kWh blocks, or choose to cover all of their monthly usage. T T

Renewable Resources shall be defined as Wind, Solar Photovoltaic, Biomass Co-Firing of Agricultural crops and all energy crops, Hydro (as certified by the Low Impact Hydro Institute), Incremental Improvements in Large Scale Hydro, Coal Mine Methane, Landfill Gas, Biogas Digesters, Biomass Co-Firing of All Woody Waste including mill residue, but excluding painted or treated lumber. All REC's purchased under Option A of this tariff shall be retained or retired by the Company on behalf of customers. T T T

RATES. N

Option A:

In addition to the monthly charges determined according to the Company's tariff under which the customer takes metered service, the customer shall also pay the following rate for the REC option of their choosing. The charge will be applied to the customer's bill as a separate line item. T

The Company will provide customers at least 30-days' advance notice of any change in the Rate. At such time, the customer may modify or cancel their automatic monthly purchase agreement. Any cancellation will be effective at the end of the current billing period when notice is provided.

A1. Solar RECs:

Block Purchase:	Charge ($ per 100 kWh block): $ 1.00/month N
All Usage Purchase:	Charge: $0.010/kWh consumed N

(Cont'd on Sheet 31-2)

DATE OF ISSUE:

DATE EFFECTIVE: Service Rendered On And After January 19, 2018

ISSUED BY: Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated XXXXXXX

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 31-2
CANCELLING P.S.C. KY. NO. 11 _________ SHEET NO. 31-2

RIDER R.P.O. T
(Renewable Power Option Rider) T

RATES. (Cont'd)

N

A2. Wind RECs:

Block Purchase:	Charge ($ per 100 kWh block): $ 1.00/month
All Usage Purchase:	Charge: $0.010/kWh consumed

A3. Hydro & Other RECs:

Block Purchase:	Charge ($ per 100 kWh block): $ 0.30/month
All Usage Purchase:	Charge: $0.003/kWh consumed

Option B:

Charges for service under option B of this Tariff will be set forth in the written agreement between the Company and the Customer and will reflect a combination of the firm service rates otherwise available to the Customer and the cost of the renewable energy resource being directly contracted for by the Customer. N

TERM.

This is a voluntary program.

Under Option A Customers may participate through a one-time purchase, or establish an automatic monthly purchase agreement. Any payments under this program are nonrefundable. Customers participating under Option A may terminate service under this Rider by notifying the Company with at least thirty (30) days prior notice. T T T

Under Option B, the term of the agreement will be determined in the written agreement between the Company and the Customer. T

SPECIAL TERMS AND CONDITIONS.

This Rider is subject to the Company's Terms and Conditions of Service and all provisions of the tariff under which the customer takes service, including all payment provisions. The Company may deny or terminate service under this Rider to customers who are delinquent in payment to the Company.

Funds collected under this Renewable Power Option Rider will be used solely to purchase RECs for the program. T

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TITLE: Managing Director, Regulatory & Finance

By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated XXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 31-3**
CANCELLING P.S.C. KY. NO. 11 _________ SHEET NO. 31-3

DATE OF ISSUE:

DATE EFFECTIVE: Service Rendered On And After January 19, 2018

ISSUED BY: Ranie K. Wohnhas

TITLE: Managing Director, Regulatory & Finance

By Authority Of an Order of the Public Service Commission

In Case No. 2017-00179 Dated XXXXXXX

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)	Case No. 2017-00179

REBUTTAL TESTIMONY OF

RANIE K. WOHNHAS

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Ranie K. Wohnhas being duly sworn, deposes and says he is the Managing Director Regulatory and Finance for Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Ranie K. Wohnhas

Ranie K. Wohnhas

COMMONWEALTH OF KENTUCKY)
) Case No. 2017-00179
COUNTY OF BOYD)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Ranie K. Wohnhas, this the 3rd day of November, 2017.

Trisha M. Young Blum

Notary Public

Notary ID Number: 530202

My Commission Expires: 3-18-19

TRISHA M. YOUNG
NOTARY ID 530202
COMMISSION EXPIRES 3-18-19

REBUTTAL TESTIMONY OF
RANIE K. WOHNHAS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

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REBUTTAL TESTIMONY OF
RANIE K. WOHNHAS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

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

A. My name is Ranie K. Wohnhas. My position is Managing Director, Regulatory and Finance, Kentucky Power Company ("Kentucky Power" or "Company"). My business address is 855 Central Ave., Ashland, Kentucky 41101.

Q. ARE YOU THE SAME RANIE K. WOHNHAS WHO PREVIOUSLY FILED DIRECT TESTIMONY IN THIS PROCEEDING ON BEHALF OF KENTUCKY POWER COMPANY?

A. Yes, I am.

II. PURPOSE OF REBUTTAL TESTIMONY

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

A. The purpose of my rebuttal testimony is to respond to the testimony of Attorney General Witness Smith and KIUC Witness Kollen. Specifically, I will respond to Intervenor testimony relating to (1) capitalization adjustments; (2) capital structure; (3) deferral of Rockport UPA expenses; (4) recommendation that the Commission write-down the Big Sandy Retirement regulatory asset; (5) the Mitchell ponds remediation liabilities; (6) recovery of expenses relating to the Company's life insurance policies; (7) recovery of aviation expenses; (8) recovery of storm damage expense; (9) recovery of the Company's relocation expense; (10)

treatment of the gain on the sale of non-utility property; (11) the Company's rate case expense; (12) the post-test year increase in the Company's employee complement; and (13) the Company's additional revenue requirement.

III. CAPITALIZATION ADJUSTMENTS

Q. ON PAGE 42 OF HIS TESTIMONY, KIUC WITNESS KOLLEN RECOMMENDS THE INCLUSION AND EXCLUSION OF CERTAIN ACCOUNTS FROM THE COMPANY'S CAPITALIZATION. DO YOU AGREE WITH HIS RECOMMENDATIONS?

A. No. It is entirely inappropriate to exclude the regulatory assets identified by Mr. Kollen (recorded in account 182.3xxx) from capitalization. The Company must finance these amounts that are owed but have not been paid. The one-sided nature of Mr. Kollen's position is evident by his focus only on regulatory assets and not on regulatory liabilities in account 254.xxxx.

Q. ARE THERE INSTANCES WHEN IT WOULD BE APPROPRIATE TO REMOVE REGULATORY ASSETS FROM CAPITALIZATION?

A. Yes. And the Company's proposed capitalization, unlike the selective adjustments proposed by Mr. Kollen, does so. It is appropriate to remove a specific regulatory asset from the Company's capitalization when the carrying cost associated with the asset is being recovered. For example, the Company appropriately removed from capitalization the amounts related to Big Sandy Decommissioning Rider as shown in Section V, Schedule 3, Column (5).

Q. DOES MR. KOLLEN PROPOSE ANY OTHER "HEADS I WIN; TAILS YOU LOSE" ADJUSTMENTS TO CAPITALIZATION?

A. Yes. A further example of Mr. Kollen's one-sided approach to adjustments is his selection of only the unrealized gains in account 175.xxxx and not also the unrealized losses in account 244.xxxx. Compounding Mr. Kollen's error is that Account 175.xxxx is a non-cash derivative balance sheet account that does not affect the Company's capitalization. For all of these reasons, Mr. Kollen's recommended adjustments to capitalization listed on page 42 of his testimony should be rejected.

Q. WHAT OTHER ADJUSTMENT TO CAPITALIZATION DOES MR. KOLLEN PROPOSE?

A. Mr. Kollen proposes to adjust capitalization by eliminating the coal inventory adjustment for low sulfur coal to reflect the target level for low sulfur coal at the Mitchell Plant.

Q. DO YOU AGREE WITH THIS RECOMMENDED REDUCTION TO CAPITALIZATION?

A. No. The Company's proposed capitalization adjustment to reflect target coal inventory level is consistent with Kentucky Power's treatment of the issue in all prior base rate cases, including most recently Case No. 2014-00396. Sometimes the adjustment requires, as is the case here, an increase in capitalization. Other times, capitalization is reduced. What is important is that the adjustments be made even-handedly and without regard to some hoped-for result. In addition, Kentucky Power recovers the cost of the coal it purchases only when it is burned. While it sits in the pile, an important benefit to customers to ensure adequate coal is available to meet the Company's generation needs, Kentucky Power incurs carrying costs. The Company is entitled to recover these carrying costs. Target coal levels serve as a reasonable proxy for the appropriate level of capitalization required to finance the Company's coal piles so as to provide reasonable and adequate service. Mr. Kollen's recommendation should be rejected.

IV. CAPITAL STRUCTURE

Q. WHAT IS MR. KOLLEN'S PROPOSED ADJUSTMENT TO THE SHORT-TERM DEBT COMPONENT OF THE COMPANY'S END OF TEST YEAR CAPITAL STRUCTURE?

A. Mr. Kollen recommends that Kentucky Power's actual end of test year capital structure be adjusted to increase the amount of short-term debt from approximately 0.06% ($1,022,872) (0.00% after the coal pile adjustment I discuss above) to 2.0%, and that long-term debt be reduced by an offsetting 200 basis points.

Q. DO YOU AGREE WITH MR. KOLLEN'S ADJUSTMENT TO CHANGE THE OVERALL CAPITAL STRUCTURE BY INCLUDING AN AMOUNT FOR SHORT TERM DEBT THAT IS NOT ON THE COMPANY'S BOOKS AS OF FEBRUARY 28, 2017?

A. No. The end of test year per books balance of short-term debt of $1,022,872 shown in Section V, Workpaper S-3, Column 3, Line 2 that the Company proposes as its level of short-term capitalization prior to the coal pile adjustment comports with the Commission's regulations.

Q. IS THIS THE ONLY REASON MR. KOLLEN'S ADJUSTMENT SHOULD BE REJECTED?

A. No. Mr. Kollen is correct that Kentucky Power's short-term debt level varied throughout the test year. What he omits from his discussion is that the amount of short-term debt varied on a daily basis through the Company's participation in the AEP Utility Money Pool ("Money Pool"). Some days the Company used short-term debt. Other days, it not only lacked short-term debt, but was in an "invested" short-term position. The Company's response to KIUC 1-50 provides its daily test-year short term debt position.

Q. HOW DOES KENTUCKY POWER ACCESS SHORT-TERM DEBT FINANCING?

A. The Money Pool is the only form of short-term debt available to the Company. The Money Pool is the portion of the Corporate Borrowing Program that is the short-term funding mechanism for all AEP's regulated utilities, including Kentucky Power. It is structured to meet the combined short-term cash management needs of those companies. The Money Pool meets the short-term cash needs of its participants by providing for short-term borrowings from the Money Pool by its participants and short-term investment of surplus funds by the same participants. The Money Pool is governed by the AEP System Amended and Restated Utility Money Pool Agreement dated as of December 9, 2004, a copy of which has been filed with FERC, and which was provided by the Company in response to KIUC 1-48.

Q. HOW DOES KENTUCKY POWER PARTICIPATE IN MONEY POOL?

A. American Electric Power Service Corporation ("AEPSC") acts as the administrative agent of the Corporate Borrowing Program, including the Money

Pool. Those members with surplus short-term funds pool their available short-term monies on a daily basis to fund the daily short-term borrowing needs of the other members. Those members requiring short-term debt to finance their operations on that day borrow from the Money Pool. The important point for the purposes of Mr. Kollen's adjustment is that the Company's invested/borrowed position changes daily. For example, during January 2017, Kentucky Power was in an invested position for 25 of the 31 days of the month. The remaining six days of January 2017 the Company was in a borrowed position. Other months, the balance was reversed, and Kentucky Power was principally in a borrowed position on a daily basis. To ascribe a 2.0% short-term capitalization to the Company is inconsistent with these facts.

Q. PUTTING ASIDE MR. KOLLEN'S FAILURE TO ADDRESS THE DAILY FLUCTUATION IN THE COMPANY'S SHORT-TERM DEBT POSITION, AND THAT ON MANY DAYS IT IS ACTUALLY INVESTED ON A DAILY SHORT-TERM BASIS, WHAT IS THE BASIS FOR MR. KOLLEN'S RECOMMENDATION THAT THE COMPANY'S ACTUAL END OF TEST YEAR LEVEL OF SHORT-TERM DEBT, PRIOR TO ADJUSTMENTS, BE REJECTED IN FAVOR OF A 2.0% LEVEL OF SHORT-TERM CAPITALIZATION?

A. He offers none in his testimony. Couching it only as a recommendation, the only evidence Mr. Kollen offers is that "at some dates" during the twelve months ended September 30, 2009, ***almost six and one-half years*** prior to the start of the test year in this case, the Company's "short-term debt was nearly 17% of capitalization." Mr. Kollen never explains, nor can he, how the Company's level of short-term on unspecified and cherry-picked dates years prior to the test year supports his recommendation. Nor does he explain why the Commission should not instead look to the Company's invested position on "some dates" during the same twelve months ended September 30, 2009 to "zero-out" the Company's short-term debt in this case.

Q. SINCE FILING HIS TESTIMONY HAS MR. KOLLEN PROVIDED AN EXPLANATION FOR HIS PROPOSED 2% SHORT-TERM DEBT LEVEL?

A. In discovery, the Company asked Mr. Kollen the basis for his recommendation of 2%. In response he stated that some month-end test year balances "were as much" as 1.1%, or slightly more than one-half of his recommended amount. He also ignores that fact that in other months the Company's level of short-term debt at month end was less than 1.1%, and that in at least one month (January 2017) the Company was in an invested position at month's end. Mr. Kollen's recommendation is without a test-year evidentiary basis, and Kentucky Power properly utilized the end-of-test year level of short-term debt, prior to adjustments, in its proposed capital structure.

V. DEFERRAL OF ROCKPORT UPA EXPENSES

Q. WHAT DOES MR. KOLLEN RECOMMEND WITH RESPECT TO ROCKPORT UNIT 2 UPA EXPENSES?

A. Mr. Kollen recommends deferring the non-fuel UPA costs from the effective date when rates are established in this proceeding through December 2022 when the

Rockport Unit 2 lease expires. The amount deferred would be established as a regulatory asset. He also recommends recovery of the regulatory asset starting in December 2022 over ten years on an annuitized basis. The recovery would include a carrying charge on the balance of the regulatory asset at the Company's weighted average cost of capital.

Q. DO YOU AGREE WITH MR. KOLLEN'S RECOMMENDATION?

A. No. The UPA expenses are incurred in connection with a FERC-approved agreement and Kentucky Power is entitled as a matter of law to their concurrent recovery. Although the WACC return that Mr. Kollen proposes would help to mitigate the financial impact on the Company, it does not fully address the impact. In particular, at the level of deferral that Mr. Kollen recommends, Kentucky Power's credit metrics would be negatively affected. The deterioration of the Company's credit metrics could potentially lead to higher financing costs for the Company.

Q. BEFORE EXPLAINING HOW KENTUCKY POWER'S CREDIT METRICS WOULD BE NEGATIVELY AFFECTED, WHAT ARE THE COMPANY'S CURRENT CREDIT RATINGS?

A. Kentucky Power currently has investment grade credit ratings of A- (Stable) and Baa2 (Stable) with S&P and Moody's, respectively.

Q. GENERALLY DESCRIBE THE METHODOLOGY USED BY EACH RATING AGENCY FOR ASSIGNING CREDIT RATINGS.

A. S&P evaluates the credit of each operating company utilizing a family approach, factoring in the ratings of all AEP system subsidiaries. S&P's family approach to bond ratings for individual operating companies stresses the inherent benefits and risks associated with having a diversified family of operating companies across AEP's eleven-state service territory.

Unlike S&P's family methodology, Moody's rates each individual operating company based on the merits of the underlying operations and credit profile of that individual operating company. Therefore, Moody's will be my primary focus when discussing Kentucky Power's credit rating.

Q. HOW DOES MOODY'S MEASURE FINANCIAL STRENGTH?

A. Financial strength accounts for 40% of Moody's rating methodology. Moody's financial measures and scores are based on ratios including interest coverage, cash flow to debt and debt to capitalization. All ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations published December 2013.

Q. WHAT IMPACT COULD THE DECREASED CASH FLOWS RESULTING FROM MR. KOLLEN'S PROPOSAL REGARDING A DEFERRAL OF ROCKPORT UPA EXPENSES HAVE ON KENTUCKY POWER'S CREDIT RATING?

A. Should further deterioration of Kentucky Power's cash flows continue, the Company could face ratings downgrade pressure and increased borrowing costs associated with future financing activity.

Cash flows from operations are a key component of the ratios utilized to score a company's financial strength. According to Moody's credit opinion published February 2017, Kentucky Power's stable rating outlook is primarily based on the expectation that Kentucky Power will maintain a constructive relationship with the KPSC and that the combination of rate actions and prudent financial policy will enable the utility to preserve financial credit metrics that support the rating. These metrics include a ratio of cash flow excluding working capital changes (CFO pre-WC) to debt in the mid-teens range. In addition, the opinion states a ratio of CFO pre-W/C to debt falling below 13% for a sustained period of time could lead to a downgrade. As of December 31, 2016, the CFO pre-WC to debt ratio for Kentucky Power was 11.8%.

Q. BRIEFLY SUMMARIZE THE IMPORTANCE OF KENTUCKY POWER'S INVESTMENT GRADE CREDIT RATINGS.

A. Timely and sufficient cost recovery is required to maintain the cash flows necessary to support a stable investment grade credit. Having investment grade credit assures the investment community the Company can service its current and future debt obligations and creates the ability to source capital at attractive rates for its customers.

Q. DOES THIS MEAN THAT THE IDEA OF A DEFERRAL AND THE ESTABLISHMENT OF A REGULATORY ASSET IS WITHOUT MERIT?

A. No. The deferral and creation of a regulatory asset at an appropriate level, and recovered over a reasonable period, if agreed to by Kentucky Power, could mitigate the impact on customer rates.

VI. BIG-SANDY REGULATORY ASSET WRITE-DOWN

Q. WHAT IS YOUR UNDERSTANDING OF MR. SMITH'S PROPOSAL REGARDING THE BIG SANDY REGULATORY ASSET.

A. Mr. Smith recommends at pages 64 and 65 of his testimony that the Commission examine a write down of some portion of the regulatory asset approved by the Commission in its October 7, 2013 Order in Case No. 2012-00578 ("Mitchell Transfer Case"). The regulatory asset currently is being recovered through the Decommissioning Rider (currently called the Big Sandy Retirement Rider). His recommendation, in which he seemingly argues both for disallowing expenses being recovered through the Big Sandy Retirement Rider and writing down some or all of the regulatory asset being recovered through the rider, is premised upon AEP's write down of approximately $2.3 billion in 2016 in connection with its subsidiaries' operations in the unregulated markets.

Q. DO YOU AGREE WITH MR. SMITH'S PROPOSAL?

A. No. The circumstances surrounding AEP's decision to record a write down in connection with unregulated operations have no bearing on Kentucky Power. Unregulated entities lack cost-based rates, and have different accounting requirements than Kentucky Power with respect to the impairment of long-lived assets. More fundamentally, Mr. Smith's premises his conclusion on the financial impact of such a write-down on "AEP" – an entity that is not regulated by this Commission, and not Kentucky Power.

Q. ARE THESE THE ONLY REASONS FOR REJECTING MR. SMITH'S SUGGESTION?

A. Far from it. Mr. Smith's recommendation is a reckless effort to rewrite history and tear up the regulatory compact that has guided the Commission's regulation of the Company, and the Company's investment of capital to provide electric service in the Commonwealth, for much of the last century.

Q. WHAT IS THE REGULATORY ASSET THAT MR. SMITH SUGGESTS THE COMMISSION CONSIDER WRITING DOWN?

A. The Commission's Order in the Mitchell Transfer Case approved, as the least cost alternative, the transfer of a fifty percent undivided interest in the Mitchell generating station to Kentucky Power and the retirement of Big Sandy Unit 2. At the time Big Sandy Unit 2 retired the following year, Kentucky Power had not recovered its investment in the unit, or the other coal-related assets at the Big Sandy Plant that were being retired, or that would be retired in connection with the Mitchell Transfer and subsequent conversion of Big Sandy Unit 1 to a gas-fired unit. Kentucky Power's investment in Big Sandy Unit 2, and the other coal-related assets at the Big Sandy generating station, were used by the Company to provide reliable and adequate electric service to the Company's customers for nearly 50 years (and more than 50 years in the case of the Big Sandy Unit 1 coal-related assets). Under well-recognized regulatory principles, as I understand them, Kentucky Power is entitled to recover the investment used to provide that service, as well as the reasonable costs associated with the demolition of the coal-related assets. The amount of this investment and the demolition costs, as well as the accompanying WACC-based carrying charge, comprise the regulatory asset being recovered through the Big Sandy Retirement Rider.

Q. WERE THE ESTABLISHMENT OF THE REGULATORY ASSET AND ITS RECOVERY MECHANISM THROUGH THE BIG SANDY RETIREMENT RIDER APPROVED BY THE COMMISSION?

A. Yes. The establishment of the regulatory asset and its recovery through a rider were presented to the Commission as part of the non-unanimous settlement agreement among all parties to the Mitchell Transfer Case other than the Attorney General. In its October 7, 2013 Order approving the Mitchell Transfer, the Commission also approved, with changes not relevant to the Big Sandy regulatory asset, the settlement agreement. In its June 22, 2015 Order in the Company's last rate case, the Commission approved the establishment of the Big Sandy Retirement Rider.

Q. DID THE ATTORNEY GENERAL APPEAL THE COMMISSION'S OCTOBER 7, 2013 ORDER IN THE MITCHELL TRANSFER CASE?

A. Yes, but on appeal the Attorney General did not challenge that portion of the October 7, 2013 Order creating the regulatory asset or providing for its recovery through a rider. In any event, the Franklin Circuit Court affirmed the Commission's October 7, 2013 Order. The Attorney General next appealed the Franklin Circuit Court's order, but he subsequently dismissed that appeal as part of an agreement with Kentucky Power and the Commission to dismiss their cross-appeals of certain procedural orders entered by the court.

Q. DID COMMISSION'S APPROVAL OF THE RECOVERY OF THE BIG SANDY REGULATORY ASSET THROUGH THE BIG SANDY

RETIREMENT RIDER PROVIDE IMPORTANT BENEFITS TO THE COMPANY'S CUSTOMERS?

A. Most certainly. The Big Sandy Retirement Rider spreads the recovery of the regulatory asset over a 25-year period. This helps spread the related expense over an extended period and mitigate the rate effect. In addition, as KIUC witness Kollen testified in explaining the rider mechanism in the Mitchell Transfer Case, the annual amount to be recovered each year is recalculated yearly based on the current year's balance. This provides a benefit that would not be available if the expense was established as part of base rates. In particular, customers automatically receive the benefits of a declining regulatory asset balance (when that occurs) instead of locking in the expense level based on the test year amount.

Q. WHAT WOULD BE THE EFFECT OF THE ADOPTION OF MR. SMITH'S SUGGESTION THAT THE COMPANY BE REQUIRED TO WRITE DOWN SOME OR ALL OF THE PREVIOUSLY-APPROVED BIG SANDY RETIREMENT RIDER?

A. I believe it would fundamentally upend the regulatory compact that exists between the Company, its customers, and the Commission. Kentucky Power is required to invest the capital necessary to provide reasonable and adequate service to its customers. In return, it is entitled to the opportunity to receive the return on and of that capital. Based upon that understanding, Kentucky Power has invested hundreds of millions of dollars of capital in its service territory, which has been used to bring electric service to tens of thousands of customers. Mr. Smith's proposal would tear up that understanding, and toss to the side a mutually beneficial arrangement that has benefitted Company and its customers since the beginning of the 20th century.

I can only speak for Kentucky Power, but in my opinion the retroactive rewriting of the regulatory compact to deny the Company the opportunity to recover its investment would cast a pall over the willingness of any regulated company to invest its capital in the Commonwealth.

Q. MESSRS. SMITH AND DISMUKES ARGUE THE WRITE-OFF IS REQUIRED TO FURTHER ECONOMIC DEVELOPMENT IN THE COMPANY'S SERVICE TERRITORY. ARE THEY CORRECT?

A. No. Economic development requires an infrastructure to support new and expanded business and an economic and regulatory climate that provides businesses – both regulated and unregulated – the opportunity to receive a return on and of their invested capital. Mr. Smith's proposal is a direct attack on the Company's ability to attract the capital to provide the required infrastructure, and the economic climate conductive to attracting new and expanded industry.

Kentucky Power has taken the lead in the promotion of new and expanded industry in its service territory. It, along the Governor's office and state and local economic development officials, coupled with actions by the General Assembly, was successful in attracting Braidy Industries to the Company's service territory. It has contributed its own funds, both in the form of grants and dollar-for-dollar matches of customer payments to the K-PEGG fund, to provide eastern Kentucky economic development officials the resources required to do their jobs. Messrs.

Smith and Dismukes would have the Commission undo these efforts, and to undermine their accomplishments.

VII. MITCHELL PONDS REMEDIATION LIABILITIES

Q. WHAT IS MR. SMITH'S CONCERN REGARDING THE LIABILITIES ASSOCIATED WITH THE REMEDIATION OF THE FOUR MITCHELL PONDS?

A. Mr. Smith suggests there is confusion regarding the ownership of the Mitchell generating station ponds and their accompanying environmental remediation liability. He also argues that the Company should not be liable for any environmental remediation liability associated with its proportionate ownership of the Mitchell generating station prior to December 31, 2013 when the Company acquired a 50% undivided interest in the station.

Q. IS THERE ANY REASONABLE BASIS FOR THAT ASSERTION?

A. No.

Q. HAS THE COMMISSION ADDRESSED KENTUCKY POWER'S LIABILITY AND REMEDIATION EXPENSE ASSOCIATED WITH THE OPERATION OF THE MITCHELL PLANT PRIOR TO ITS TRANSFER EFFECTIVE DECEMBER 31, 2013?

A. Yes. In connection with its October 7, 2013 approval of the Mitchell Transfer, the Commission also approved the Company's assumption of a 50% undivided share of the Mitchell generating station's existing liabilities. Those liabilities, which were net against the value of the transferred assets and used to determine the net book value at which the transfer was made, included a 50% share of environmental liabilities associated with past operation of the plant. Company Witness Osborne provides more detail on the Company's liability for the remediation costs associated with Mitchell generating station ponds.

VIII. CASH SURRENDER VALUE OF LIFE INSURANCE POLICIES

Q. DO YOU AGREE WITH MR. SMITH RECOMMENDATION (C-13) TO REMOVE $26,941 IN KENTUCKY JURISDICTIONAL EXPENSES ASSOCIATED WITH THE CASH SURRENDER VALUE OF LIFE INSURANCE POLICIES FOR FORMER EXECUTIVES?

A. No. Mr. Smith gives no explanation supporting his recommendation other than ratepayers should not be responsible for paying for expenses for former executives. But the expense is part of the total compensation/benefit package given to executives (current or former) and is a prudent expense and should be recovered. The issue of whether the executive is current or former has no bearing on whether the cost should be recovered.

IX. CORPORATE AVIATION

Q. WHAT SPECIFIC CORPORATE AVIATION EXPENSES DOES MR. SMITH RECOMMEND TO DISALLOW FROM THE COMPANY'S FILING?

A. Mr. Smith recommends a disallowance of all corporate aviation expenses charged from the service corporation AEPSC.

Q. WHAT REASONS DOES HE GIVE TO SUPPORT THIS DISALLOWANCE?

A. None. In his testimony he only states that affiliate charges require increased scrutiny. Commission Data Request 7(b) directs the Attorney General to explain the basis for rendering all aviation expense unallowable for ratemaking purposes. Mr. Smith was unable to do so other than to refer to the Commission back to his unsupported and insupportable testimony.

Q. SHOULD THESE CORPORATE AVIATION COST BE DISALLOWED?

A. No. These are prudently incurred and reasonable costs of doing business, and Kentucky Power Company has been allocated its appropriate share.

X. STORM DAMAGE EXPENSE

Q. DO YOU AGREE WITH MR. SMITH'S PROPOSAL TO ELIMINATE THE COMPANY'S ADJUSTMENT TO INCREASE STORM DAMAGE EXPENSE?

A. No. Again, Mr. Smith fails to provide any evidentiary basis for his recommendation. His only comment is "The Company has not demonstrated a compelling reason to increase test year storm damage expense." The uncertainty of when and for how much a major storm will impact the Company is the reason for using a three-year average. Using a three-year average creates a normalized level of costs for both the customer and the Company. Over the past eight years the Company has incurred incremental major storm costs of between $23.1M and

$0.8M. There were 23 storms during this 8-year period totaling $50.8M for an average of $6.4M per year. Using only the test year amount in any base rate filing can lead to major swings in adjustments that are neither helpful to the customers nor the Company. Mr. Smith's proposal to eliminate the adjustment to normalize storm damage expense should be rejected.

XI. RELOCATION EXPENSES

Q. DO YOU AGREE WITH MR. SMITH'S PROPOSAL TO AVERAGE RELOCATION EXPENSES OVER A THREE-YEAR PERIOD?

A. No. Kentucky Power properly included the full test year amount of relocation expense in its revenue requirement. Utilizing a three year average, as Mr. Smith recommends, is appropriate only where there exists significant yearly volatility and the financial impact of the expense is significant. For those expenses, a longer view of the expense is necessary to properly determine a going level amount. Unlike steam maintenance or storm damage expense, relocation expense is not significant and does not vary materially from year to year. Accordingly, a three-year average is not necessary for relocation expense.

Moreover, Mr. Smith's recommendations regarding when a three-year average should be used for expenses are inconsistent. He recommends that the Commission reject a three-year average for the significant and variable storm damage expense, but proposes a three-year average for relocation expenses which is much less volatile and results in a far lower financial impact.

XII. GAIN ON SALE OF NON-UTILITY PROPERTY

Q. DO YOU AGREE WITH MR. SMITH'S ADJUSTMENT TO AMORTIZE THE GAIN ON THE SALE OF THE CARRS SITE OVER THREE YEARS?

A. No. As indicated in the Company's response to AG_D_WP_7 e, for the last 33 years, the Company has not included the Carrs Site in rate base and therefore has not received a return on this property. With respect to property taxes on the Carrs Site, the Company removed $60,539 from Taxes Other than Income Taxes in the Cost of Service. See the Company's supplemental response to AG_D_WP_7 e. Therefore, there is no basis to assign any of the gain realized on the sale of the Carrs Site to ratepayers.

XIII. RATE CASE EXPENSE

Q. DO YOU AGREE WITH MR. SMITH'S EXCLUSION OF CERTAIN RATE CASE EXPENSE ITEMS?

A. No. Mr. Smith recommends rejecting the Company's expenses paid to the Communication Counsel of America, Inc. ("CCA"). The Company utilizes CCA for witness training and hearing preparation. Witness preparation is a necessary part of preparing and litigating a base rate case and regardless of who performs this function the cost should be recovered. Had the Company elected to use its legal team to perform this function, the estimated legal expense of $510,000 would have been higher. The expense is both prudently incurred and reasonable in amount.

Q. MR. SMITH ALSO ARGUES THAT THE COMMISSION SHOULD DISALLOW THE COMPANY'S RATE CASE EXPENSE IN THE

CURRENT PROCEEDING AND DIRECT KENTUCKY POWER NOT TO FILE ANOTHER KENTUCKY RATE CASE UNTIL THE COMPANY FILES AN ACTION TO REDUCE THE RETURN ON EQUITY COMPONENT OF THE CHARGES PAID IN CONNECTION WITH THE ROCKPORT UPA. DO YOU AGREE?

A. Absolutely not. This is another example of Mr. Smith's reckless approach to utility regulation and the law. Kentucky Power has a right under the Constitution of the United States, and Kentucky statutory law, to receive fair, just, and reasonable rates. Mr. Smith asks the Commission to strip the Company of both rights. In addition, the Rockport UPA is a FERC-approved agreement and the Company is entitled under law to the concurrent recovery of all expenses related to the agreement.

The determination of whether the ROE component of the rates and charges paid by Kentucky Power under the Rockport UPA is fair, just, and reasonable lies exclusively with FERC. Kentucky Power has explained in discovery requests that an action before FERC to re-open the ROE component of the Rockport UPA could lead to the re-opening other UPA provisions, and that on-balance the Company has concluded that risks of filing a FERC action outweigh any benefits. The Commission should not allow itself to be party to the Attorney General's invitation to employ unlawful and unconstitutional means to overturn this judgment.

<u>XIV. POST-TEST YEAR INCREASE IN EMPLOYEE COMPLEMENT</u>

Q. WHAT IS MR. KOLLEN'S RECOMMENDATION CONCERNING THE EXPENSE ASSOCIATED WITH THE KNOWN AND MEASURABLE CHANGES RESULTING FROM THE COMPANY'S ADDITION OF FIVE ADDITIONAL EMPLOYEES?

A. Mr. Kollen proposes that the Commission disallow the expense in its entirety. He contends that the staffing is contingent upon Commission approval and constitutes a selective post-year adjustment.

Q. DO YOU AGREE WITH MR. KOLLEN'S ASSESSMENT?

A. No. The five employees have been hired. In the Company's response to AG 1-069 it indicated that four of the five positions had been filled. Subsequent to that response, the Company hired the fifth person. Contrary to Mr. Kollen's understanding, the Company was not seeking Commission approval to increase its employee complement and the Commission likely would be extremely wary of managing the day-to-day operations of the Company. Witness Satterwhite in his direct testimony explains the additional staffing is both required and will improve safety, customer service, reliability, and revenue protection. The adjustment is known and reasonable and should be approved.

Q. DOES MR. SMITH PROPOSE TO DISALLOW THE PROPOSED ADJUSTMENT?

A. No. Mr. Smith instead proposes to increase the Company's operating revenues related to estimated energy theft recoveries by adding administrative associate for the revenue protection group. Mr. Kollen, in a somewhat similar fashion, argues the Company's proposed adjustment is selective because it does reflect anticipated revenues.

Q. ARE THESE POSITIONS SUPPORTABLE?

A. No. In my direct testimony, I state that the Company estimates it can increase its annual energy theft recoveries by up to 50%. It is just an estimate. Mr. Smith's adjustment of $166,698 assumes that the Company will have increased recoveries of 50%. The actual recoveries are not known and measurable at this time and as such Mr. Smith's adjustment should be rejected.

XV. THE COMPANY'S REVENUE REQUIREMENT

Q. KIUC AND THE ATTORNEY GENERAL HAVE RECOMMENDED ADDITIONAL REVENUE REQUIREMENTS FOR KENTUCKY POWER OF APPROXIMATELY $13.4 MILLION AND $40 MILLION RESPECTIVELY. HAVE THEY SUPPORTED THESE RECOMMENDATIONS?

A. No. The Company's evidence, including its direct and rebuttal testimony, as well as its responses to data requests, demonstrate that Kentucky Power is entitled under the law to additional annual revenues of $60.4 million. The adjustments and other recommendations relied upon by KIUC and the Attorney General to support their recommended additional revenue requirements do not bear scrutiny and would deny the Company the revenues required to permit it to provide reasonable, adequate, and efficient service.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.