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**

KENTUCKY POWER RESPONSES TO

KCTA'S

SECOND SET OF DATA REQUESTS

September 20, 2017

VERIFICATION

The undersigned, Jason A Cash, being duly sworn, deposes and says he is employed by American Electric Power as Accountant Policy and Research Staff that he has personal knowledge of the matters set forth in the forgoing data requests and the information contained therein is true and correct to the best of his information, knowledge and belief

Jason A Cash

STATE OF OHIO	)	
	)	2017-00179
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Jason A Cash, this the 20th day of September 2017.

Notary Public

Notary ID Number: 2014-RE-488323

SARAH SMITHHISLER - NOTARY PUBLIC
MY COMMISSION EXPIRES 04-29-19
STATE OF OHIO

My Commission Expires: 04/29/19

VERIFICATION

The undersigned, Tyler H Ross being duly sworn, deposes and says he is the Director Regulatory Accounting Services for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief

Tyler H Ross

Tyler H Ross

STATE OF OHIO	)	
	)	Case No. 2017-00179
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Tyler H Ross, this the 14th day of September 2017.

S. Smithhisler

Notary Public

SARAH SMITHHISLER - NOTARY PUBLIC
MY COMMISSION EXPIRES 04-29-19
STATE OF OHIO

My Commission Expires: 04/29/19

VERIFICATION

The undersigned, Stephen L. Sharp, being duly sworn, deposes and says he is a Regulatory Consultant, for Kentucky Power Company and that he has personal knowledge of the matters set forth in the data responses and the information contained therein is true and correct to the best of his information, knowledge and belief

Stephen L. Sharp

COMMONWEALTH OF KENTUCKY)
) 2017-00179
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Stephen L Sharp, this the 18th day of September 2017.

Judy K Rosquist
Notary Public

Notary ID Number: 571144

My Commission Expires: January 23, 2021

VERIFICATION

The undersigned, Alex E. Vaughan, being duly sworn, deposes and says he is the Manager, Regulatory Pricing and Analysis that he has personal knowledge of the matters set forth in the forgoing responses and the information contained therein is true and correct to the best of his information, knowledge and belief.

Alex E. Vaughan

STATE OF OHIO)
) Case No. 2017-00179
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Alex E. Vaughan, this the 14 day of September 2017.

NOTARIAL SEAL
STATE OF OHIO

Princess M. Brown
Notary Public, State of Ohio
My Commission Expires 04-19-2020

Notary Public

My Commission Expires: 4/19/2020

VERIFICATION

The undersigned, Ranie K. Wohnhas, being duly sworn, deposes and says he is the Managing Director Regulatory and Finance for Kentucky Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that 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 18th day of September 2017.

Judy K Rosquist #571144

Notary Public

My Commission

Expires January 23, 2021

DATA REQUEST

KCTA_2_001 Please provide a copy of the calculations used to derive the current CATV pole attachment charges of $7.21 for attachments on a two-user pole and $4.47 for attachments on a three-user pole.

RESPONSE

The current CATV pole attachment rates were developed as part of a unanimous settlement agreement in Case No. 2005-00341. No calculations were used to derive the agreed-upon rates. KCTA was an intervenor in that case and a signatory to the settlement agreement.

Witness: Stephen L. Sharp

DATA REQUEST

KCTA_2_002 Referring to KPCO Exhibit E, Pages 112-116, Tariff C.A.T.V Issued June 28, 2017, please provide a copy of the corresponding superseded tariff pages.

RESPONSE

Exhibit E is the version of the tariffs proposed by the Company in this case showing changes from the current version in strikethrough or italicized additions as required by 807 KAR 5:001, Section 16(b)(4)(b). The Company's current tariffs can be found on the Kentucky Public Service Commission's website at http://psc.ky.gov/Home/Library?type=Tariffs&folder=Electric.

Witness: Stephen L. Sharp

DATA REQUEST

KCTA_2_003 To the extent not otherwise clearly identified in your response to 2_002 above, identify any and all changes in tariff language included in the June 28, 2017 Tariff vis-à-vis the corresponding superseded tariff pages.

RESPONSE

Exhibit E is the version of the tariffs proposed by the Company in this case showing changes from the current version in strikethrough or italicized additions as required by 807 KAR 5:001, Section 16(b)(4)(b).

Witness: Stephen L. Sharp

DATA REQUEST

KCTA_2_004 Please provide a copy of any narrative or Q. and A. testimony included in KPCO's rate case package on the subject of pole attachment charges, along with any supporting exhibits not otherwise provided in response to KCTA data requests.

RESPONSE

Kentucky Power objects to this request as unduly burdensome to the extent it requires the Company to categorize the extensive public record in this case. Without waiving this objection, the Company's proposed changes to Tariff C.A.T.V. can be found in Company Witness Sharp's Testimony.

Witness: Stephen L. Sharp

DATA REQUEST

KCTA_2_005 To the extent different from that authorized by the Commission in Final Order Case No. 2014-00396, identify the rate of return that KPCO is proposing in connection with this rate case corresponding to the currently authorized rate of return of 7.34% used by KPCO in the calculation of the CATV Attachment Fees as provided in KPCO_R_KCTA_1_3_Attachment1.xlsx and KPCO_R_KCTA_1_4_Attachment1.xlsx.

RESPONSE

As shown on Line 53 of Exhibit SLS-2 to the testimony of Company Witness Sharp, the Company utilized the rate of return authorized by the Commission in the Final Order in Case No. 2014-00396 in its calculation of the proposed CATV pole attachment fees.

Witness: Stephen L. Sharp

DATA REQUEST

KCTA_2_006 Please provide copies of any studies or documentation in support of the annual depreciation rate for poles used by KPCO in the calculation of the CATV Attachment Fees as provided in KPCO_R_KCTA_1_3_Attachment1.xlsx and KPCO_R_KCTA_1_4_Attachment1.xlsx.

RESPONSE

As shown on Line 35 of Exhibit SLS-2 to the testimony of Company Witness Sharp, under the Report Reference or Formula column, the annual depreciation rate used was the rate identified in Exhibit 11 of the Final Order in Case No. 2014-00396. Please refer to http://psc.ky.gov/pscscf/2014%20Cases/2014-00396//20150622_PSC_ORDER.pdf (Page 133 of 162) for the Commission's Final Order in Case No. 2014-00396. The Company's distribution plant depreciation rates have remained unchanged since Case No. 91-066.

Witness: Jason A. Cash

DATA REQUEST

KCTA_2_007	To the extent different from that authorized by the Commission in Final Order Case No. 2014-00396, identify the annual depreciation rate for poles that KPCO is proposing in connection with this rate case corresponding to the currently authorized annual rate of 3.52% used by KPCO in the calculation of the CATV Attachment Fees as provided in KPCO_R_KCTA_1_3_Attachment1.xlsx and KPCO_R_KCTA_1_4_Attachment1.xlsx.

RESPONSE

Kentucky Power is not proposing to amend the Company's distribution plant depreciation rates in this case.

Witness: Jason A. Cash

DATA REQUEST

KCTA_2_008 To the extent KPCO has proposed a depreciation rate for poles different from that authorized by the Commission in Final Order Case No. 2014-00396, provide copies of any studies or documentation in support of the new depreciation rate.

RESPONSE

Kentucky Power is not proposing to amend the Company's distribution plant depreciation rates in this case.

Witness: Jason A. Cash

DATA REQUEST

KCTA_2_009 Identify the plant specific average service life for pole plant investment booked to Account 364.

RESPONSE

The plant specific average service life for pole plant investment booked to Account 364 is 28 years as set forth in the most recent distribution plant depreciation study conducted by the Company. A copy of this depreciation study is included as Exhibit DAD-2 to the testimony of Company Witness Davis in Case No. 2014-00396, and is available at www.psc.ky.gov.

Witness: Jason A. Cash

DATA REQUEST

KCTA_2_010 Provide detail subaccount totals for Account 593 for years 2015 and 2016.

RESPONSE

Please refer to KPCO_R_KCTA_2_010_Attachment1.xls for the requested information.

Witness: Tyler H. Ross

DATA REQUEST

KCTA_2_011 Please provide the information requested in the previous request (KCTA_2_0010) for each of the preceding five years 2010 – 2014.

RESPONSE

Please refer to KPCO_R_KCTA_2_011_Attachment1.xls for the requested information.

Witness: Tyler H. Ross

DATA REQUEST

KCTA_2_012 Provide the underlying general ledger accounting data in native electronic format to support the subaccount summary detail data provided in your response to KCTA_2_0010 for years 2015 and 2016.

RESPONSE

Please refer to KPCO_R_KCTA_2_012_Attachment1.xls and KPCO_R_KCTA_2_012_Attachment2.xls for the requested information for 2015 and 2016, respectively.

Witness: Tyler H. Ross

DATA REQUEST

KCTA_2_013 To the extent not otherwise clearly identified in the subaccount summary detail or the general ledger data for Account 593 provided in response to requests 2_0010 and 2_012, identify all expenses booked to Account 593 for years 2015 and 2016 that are associated with a regulatory asset, including but not limited to the Storm Related Costs of $4,377,336 and $ 10,931,400 identified in KYPO's 2016 FERC Form 1 at Pages 123.26 and 232.

RESPONSE

For 2015, the expenses that are associated with a regulatory asset were $3,563,821.98 recorded in Account 5930010 with a journal id of STORMAMORT as included in KPCO_R_KCTA_2_012_Attachment1.xls that is provided in the Company's response to KCTA 2-012. The $3,563,821.98 in storm expense amortization includes $2,349,222 of expense related to 2009 major storm damage which was amortized from July 2010 through June 2015 and $1,214,599.98 of expense related to 2012 major storm damage which is being amortized from July 2015 through June 2020.

For 2016, the expenses that are associated with a regulatory asset were $2,429,199.96 recorded in Account 5930010 with a journal id of STORMAMORT as included in KPCO_R_KCTA_2_012_Attachment2.xls that is provided in the Company's response to KCTA 2-012. The $2,429,199.96 in storm expense amortization is related to 2012 major storm damage which is being amortized from July 2015 through June 2020.

Witness: Tyler H. Ross

DATA REQUEST

KCTA_2_014 To the extent not otherwise clearly identified in the subaccount summary detail or the general ledger data for Account 593 provided in response to requests 2_0010 and 2_012, identify each and every credit item (i.e., reversal of expenses) associated with a regulatory asset for years 2015 and 2016, including, but not limited to the Storm Related Costs identified in KYPO’s 2016 FERC Form 1 at Pages 123.26 and 232.

RESPONSE

For 2015, the credits (deferral of expenses) that are associated with a regulatory asset were $4,377,336 recorded in Account 5930000 with a Journal ID of STORMDEFER as included in KPCO_R_KCTA_2_012_Attachment1.xls provided in the Company's response to KCTA 2-012. The $4,377,336 credit is to defer 2015 major storm damage expenses.

For 2016, there were no credits (deferral of expenses) that are associated with a regulatory asset for Account 593.

Witness: Tyler H. Ross

DATA REQUEST

KCTA_2_015 Please provide a detailed narrative explanation of the manner in which KPCO has accounted for the Storm Related Costs identified in request 2_013 relating to KPCO Account 593 maintenance expense and how that accounting has impacted KYPO's pole attachment rate calculations for 2015 and 2016.

RESPONSE

Kentucky Power's distribution business unit establishes specific work orders to track major storm costs. The 2016 Commission Order in Case No. 2016-00180 requires utilities to seek and receive Commission approval prior to deferring eligible major storm expenses and recording a regulatory asset for incremental storm damage expense not currently recovered in base rates. This Commission Order also allows utilities to defer major storm expenses occurring in the fourth quarter of the fiscal year for accounting purposes only, subject to providing the Commission with notice within five days of the establishment of the deferred asset, and also subject to the utility's filing of an application within 90 days of the occurrence of the major storm seeking Commission approval for such authority. Following Commission approval to defer major storm expenses, Kentucky Power must seek Commission approval to recover such major storm expenses in a future base rate case.

Management determines when to defer major storm expenses upon: a) receiving Commission approval to defer major storm expenses and b) the Company's evaluation of the probability of future regulatory recovery in accordance with Generally Accepted Accounting Principles (GAAP).

For the calculation of Kentucky Power pole attachment rates, storm expense/pole maintenance expenses recorded to Account 593 is a component in the calculation of Kentucky Power's annual net pole cost that is billed to pole users based on the percentage of pole used.

Witness: Tyler H. Ross

DATA REQUEST

KCTA_2_016 Please provide copies of Final Order Case No. 2014-00396 and Final Order Case No. 2016-00180 pertaining to Storm Related Costs relating to KPCO Account 593 maintenance expense.

RESPONSE

Please refer to KPCO_R_KCTA_002_016_Attachment1.pdf and KPCO_R_KCTA_002_016_Attachment2.pdf for the requested information.

Witness: Ranie K. Wohnhas

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of

APPLICATION OF KENTUCKY POWER COMPANY FOR AN ORDER APPROVING ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES RELATED TO THE EXTRAORDINARY EXPENSES INCURRED BY KENTUCKY POWER COMPANY IN CONNECTION WITH TWO 2015 MAJOR STORM EVENTS	))))))	CASE NO. 2016-00180

ORDER

On May 31, 2016, Kentucky Power Company ("Kentucky Power") filed an application seeking authority to establish a regulatory asset for incremental operation and maintenance costs it incurred in connection with repairing damages and restoring electric service to customers following two 2015 Major Event[1] storms in its service area.[2] The two storms were a snowstorm on March 4, 2015, and three waves of thunderstorms beginning on July 13, 2015, that passed through Kentucky Power's service territory by the evening of July 14, 2015. Kentucky Power seeks approval for a regulatory asset in the amount of $4,694,230.

[1] Under Institute of Electrical and Electronic Engineers ("IEEE") Standard 1366, a Major Event is one that exceeds reasonable design and/or operational limits of the electric power system. A Major Event Day is defined by IEEE Standard 1366 as any day in which the System Average Interruption Duration Index ("SAIDI") exceeds the threshold value of $T_{med.}$ The T_{med} threshold value in turn is calculated at the end of each reporting period, typically a calendar year, using data from the previous five years. It is calculated by taking the average of natural logarithm of each daily SAIDA during the previous five-year period. The standard deviation of the five-year data set is then determined and the threshold value of T_{med} is set at 2.5 standard deviations. Any day in the subsequent reporting period that exceeds the T_{med} is classified as a Major Event Day.

[2] Kentucky Power is not proposing to establish a regulatory liability in this case, even though the case style states otherwise. *See* Kentucky Power's response to Commission Staff's Second Request for Information ("Staff's Second Request"), Item 9.

Kentucky Power states that at the peak of the March snowstorm, there were 190 active outage cases affecting 6,326 of its customers. In total, there were 691 outage cases experienced on Kentucky Power's distribution system caused by heavy snow and ice on, and mudslides and flooding near, its distribution system.

Throughout the course of the thunderstorms that began on the afternoon of July 13, 2015, 2,204 outage cases were recorded on Kentucky Power's system. At the height of the outages, there were 883 active outage cases, and 30,707 Kentucky Power customers were without power. As a result of the July thunderstorms, five counties in Kentucky Power's service territory, Johnson, Rowan, Breathitt, Carter, and Perry, were declared federal disaster areas.

Kentucky Industrial Utility Customers, Inc. ("KIUC") is the only intervenor in this proceeding. A procedural schedule was established on June 17, 2016, for the processing of this matter. Commission Staff ("Staff") issued two rounds of information requests, and KIUC issued one round of information requests, to which Kentucky Power responded. Kentucky Power also filed responses to questions posed during a September 23, 2016 informal conference. The record is complete and the case now stands submitted for decision.

KENTUCKY POWER'S REQUEST

Kentucky Power is requesting a deferral of $4,694,230 in incremental Major Event storm-related expenses. The deferral consists of $285,609 for the March 2015 storm and $4,408,621 for the July 2015 storms.[3] Kentucky Power states that the amount of its requested deferral is 3.77 times the $1,243,763 in operation and

[3] Response to Staff's Second Request, Item 1.

maintenance major storm-related expenses currently included in its base rates.[4] Additionally, Kentucky Power states that if the costs for which it is now seeking authority to establish a regulatory asset had been expensed in 2015, its return on equity ("ROE") for 2015 would have been reduced from 4.21 percent to approximately 3.78 percent.[5] Kentucky Power seeks to accumulate and defer for review and recovery in its next base rate proceeding the $4,694,230 in incremental and extraordinary costs it incurred in repairing damage and restoring service in connection with the two 2015 Major Event storms.[6]

Kentucky Power relies on Financial Accounting Standards Board Standards Codification 980-340-25-1 ("FASB Codification 980-340-25-1") as authority for the creation under prescribed circumstances of a regulatory asset.[7] FASB Codification 980-340-25-1 states, in relevant part, as follows:

> Rate actions of a regulator can provide reasonable assurance of the existence of an asset. **An enterprise shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met:**

[4] Kentucky Power's base rates changed on June 30, 2015. The $1,243,763 referenced by Kentucky Power is the average of $904,953, the amount included in base rates in the first half of 2015, and $1,608,410, the amount included in base rates in the second half of 2015, after adjusting for the retail jurisdictional percentage.

[5] Application at 13.

[6] *Id.*

[7] Application at 11, paragraph 29.

> a. It is probable (as defined in Topic 450) that future revenue in an amount at least equal to the capitalized cost will result from the inclusion of that cost in the allowable cost for ratemaking purposes.
>
> b. Based on the available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs . . . .

(Emphasis in original)

Kentucky Power also relies upon prior Commission decisions granting Kentucky Power and other utilities similar accounting treatment for extraordinary and significant storm damage costs. In Case Nos. 2012-00445[8] and 2009-00352,[9] Kentucky Power was authorized to establish regulatory assets for extraordinary and significant costs incurred associated with restoration efforts resulting from storm damages occurring in 2012 and 2009, respectively. Kentucky Power claims that, relying on the accounting treatment authorized in those cases and on FASB Codification 980-340-25-1, it was allowed to make the appropriate adjustments on its books of account and was permitted to remove its 2015 extraordinary storm-related costs from its income statement for calendar year 2015. Accordingly, Kentucky Power made two entries to record the regulatory asset in Federal Energy Regulatory Commission Account 182, one in July 2015 for $4,377,336 and one in March 2016 for $381,439.90.[10] Kentucky Power's

[8] Case No. 2012-00445, *Application of Kentucky Power Company for an Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities Related to the Extraordinary Expenses Incurred by Kentucky Power Company in Connection with Four 2012 Major Storm Events* (Ky. PSC Jan. 7, 2013).

[9] Case No. 2009-00352, *Application of Kentucky Power Company for an Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities Related to the Extraordinary Expenses Incurred by Kentucky Power Company in Connection with Three Major Event Storms in 2009* (Ky. PSC Dec. 22, 2009).

[10] Kentucky Power later corrected the amount of the March 2016 journal entry, stating that it should have been for $316,894. *See* September 23, 2016 Informal Conference Memorandum handout.

request for a regulatory asset is for accounting purposes only, with ratemaking treatment deferred for consideration in its next base rate proceeding.[11]

DISCUSSION

Having reviewed the record and being otherwise sufficiently advised, the Commission finds that Kentucky Power's total 2015 storm-related damage and service-restoration costs at issue herein are extraordinary and significant in nature based on their magnitude and the amount of storm damage expenses built into its base rates. Reflecting the entire 2015 storm costs as expenses on Kentucky Power's 2015 books would have a significant impact on its 2015 financial results. The number of customers without service dictated an extraordinary effort on the part of Kentucky Power to restore service, an effort from which it incurred an extraordinarily high level of costs.

The Commission has previously approved regulatory assets for Kentucky Power and other jurisdictional utilities.[12] Such approval has been granted when a utility has incurred (a) an extraordinary, nonrecurring expense which could not have reasonably been anticipated or included in the utility's planning; (b) an expense resulting from a statutory or administrative directive; (c) an expense in relation to an industry-sponsored

[11] *Id*. at 6.

[12] The Commission approved the establishment of regulatory assets for Asset Retirement Obligation-related depreciation and accretion expenses for Louisville Gas and Electric Company and Kentucky Utilities Company when those utilities adopted Statement of Financial Standards No. 143, *Accounting for Asset Retirement Obligations*, respectively, in Case No. 2003-00426, *Application of Louisville Gas and Electric Company for an Order Approving an Accounting Adjustment to be Included in Earnings Sharing Mechanism Calculations for 2003* (Ky. PSC Dec. 23, 2003), and Case No. 2003-00427, *Application of Kentucky Utilities Company for an Order Approving an Accounting Adjustment to be Included in Earnings Sharing Mechanism Calculations for 2003* (Ky. PSC Dec. 23, 2003).

initiative; or (d) an extraordinary or nonrecurring expense that over time will result in a saving that fully offsets the cost.[13]

Kentucky Power believes its request to establish a regulatory asset for the 2015 Major Event storm-related costs, which exceed the storm-related costs in its base rates, is consistent with the first category identified above.[14] Given the nature and impact of these costs, the Commission will authorize Kentucky Power to establish, for accounting purposes only, a regulatory asset based on its incremental, actual storm-related costs for the damage and service restoration costs it incurred and deferred in 2015 as a result of the two Major Event storms occurring in 2015.

The Commission, however, will limit the amount of the authorized deferral to the amount that was not expensed. The Commission is concerned that Kentucky Power's application sets forth conflicting statements with regard to when it recorded on its books the costs related to the 2015 Major Event storms. Only through two rounds of discovery and an informal conference did it become clear that a portion of the amount requested as a regulatory asset had been recorded as an expense on Kentucky Power's 2015 books and was not reflected as a deferral until after its 2015 books were closed and financial statements were finalized. This critical information should have been disclosed by Kentucky Power in its application. In particular, we note that Kentucky Power initially recorded the entire $4,694,230 requested deferral amount on its books as an expense

[13] 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*, final Order at 4 (Ky. PSC Dec. 23, 2008).

[14] Application at 12.

in 2015.[15] However, prior to the closing of its 2015 books, Kentucky Power recorded $4,377,336 of the $4,694,230 as a deferral on its 2015 books.[16] As a result, the balance of the requested deferral, $316,894, remained on Kentucky Power's 2015 books as an expense. The remaining $316,894 was recorded as a deferral in March 2016 on its 2016 financial statements.[17] The Commission has historically not allowed a utility to establish a regulatory asset after a cost has been recorded as an expense and the utility has closed its books for the relevant fiscal year. This is in recognition of the fact that the recorded expense item is reflected in the utility's earnings for that fiscal year. To do otherwise could result in a specific cost being recorded as an expense twice. Accordingly, the Commission finds that Kentucky Power should be allowed to create and record a regulatory asset for its actual costs incurred to restore service during the two 2015 Major Event storms, and which it deferred in 2015 prior to closing its 2015 books, in the amount of $4,377,336. Kentucky Power has not requested to earn a return on this regulatory asset and the Commission is not authorizing a return on this regulatory asset.

The Commission is also troubled that Kentucky Power recorded the 2015 Major Event storm-related expenses in its 2015 books as a regulatory asset without first obtaining Commission authorization to do so. With respect to the March 4, 2015 snowstorm, the last journal entry was recorded in September 2015; for the July 2015

[15] Kentucky Power's response to Commission Staff's Informal Conference Information Request, Item 2 ("Staff's IC Request").

[16] *Id.*

[17] *Id. See* also fn. 10.

thunderstorms, the last journal entry was recorded in January 2016.[18] Because it wanted to ensure that the actual costs associated with the 2015 Major Event storms would be booked as a regulatory asset, and due to when the last actual cost was recorded, Kentucky Power indicated that there was insufficient time for it to obtain Commission approval for the deferral before closing its 2015 books.[19] Kentucky Power knew, or should have known, that the application should have been filed before Kentucky Power recorded the regulatory asset, even if doing so meant that cost estimates would have been used in the application. Based on the information provided by Kentucky Power in its application and in responses to information requests, the Commission believes the circumstances merit approval of a regulatory asset of $4,377,336. As previously stated, the authorization to establish the regulatory asset as requested by Kentucky Power is for accounting purposes only. The Commission's determination of the amount of the regulatory asset authorized herein that is to be amortized and recovered in rates will be determined in Kentucky Power's next rate case, following a detailed review of Kentucky Power's storm preparedness, its response to the outages, and system reliability, all of which are issues of great interest to the Commission. Particular attention will be paid to the effectiveness of Kentucky Power's vegetation management program to mitigate outages as a result of additional funds for reliability improvements authorized in Case No. 2014-00396, Kentucky Power's last rate case. It is expected that the scope of the Commission's review will include Kentucky Power's efforts to "harden" its system as opportunities to do so arise and the

[18] Response to Staff's Second Request, Item 2.b. and the response to Staff's IC Request, Item 1.

[19] Response to Staff's Second Request, Item 2.a.(1).

recommendations it adopted in response to the Commission's Report on the 2008 Wind Storm and the January 2009 Ice Storm.[20]

Finally, we take this opportunity to place Kentucky Power and all jurisdictional utilities on notice that Commission authorization is required before a utility can record as a regulatory asset an expense that meets one or more of the four criteria cited earlier in this order. The Commission believes that to provide reasonable assurance of a utility's ability to recover the cost of items that meet one or more of the four criteria cited earlier in this order which the Commission has used to authorize the establishment of regulatory assets the utility must be able to show that Commission approval to establish the regulatory asset has been granted.

IT IS THEREFORE ORDERED that:

1. Kentucky Power is authorized to establish a regulatory asset in the amount of $4,377,336 based on its actual costs deferred in 2015 for storm damages and service restoration due to the two 2015 Major Event storms that affected customers in its service area.

2. Kentucky Power is denied authority to establish a regulatory asset in the amount of $316,894 of storm-damage costs related to the two Major Event storms that were expensed in 2015.

3. The regulatory asset account established in this case is for accounting purposes only.

4. The amount, if any, of the regulatory asset authorized herein that is to be amortized and recovered in rates shall be determined in Kentucky Power's next rate

[20] Kentucky Power's response to Commission Staff's First Request for Information, Items 14 and 15.

case based on an examination of its storm preparedness, its storm-damage restoration efforts, reliability improvement efforts and the reasonableness of the costs incurred.

5. Kentucky Power and all jurisdictional utilities shall receive Commission authorization prior to recording regulatory assets on its books for accounting purposes as discussed in this order.

By the Commission

ENTERED
NOV 03 2016
KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

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Executive Director

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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	)	CASE NO. 2014-00396

INDEX

Page No.

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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	)	CASE NO. 2014-00396

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 172,000 consumers in all or portions of 20 counties in eastern Kentucky.[1] The most recent adjustment of its base rates was in June 2010 in Case No. 2009-00459.[2] This Order addresses a non-unanimous Settlement Agreement ("Settlement")[3] between Kentucky Power and two intervening parties, as well as issues contested by one of the intervenors that was not a signatory to the Settlement. As discussed in detail herein, and subject to some modifications, the Commission is approving the Settlement with this Order.

[1] Application at 2 lists the 20 counties. Kentucky Power also furnishes electric service at wholesale to the city of Olive Hill and the city of Vanceburg.

[2] Case No. 2009-00459, *Application of Kentucky Power Company for a General Adjustment of Electric Rates* (Ky. PSC June 28, 2010).

[3] Settlement (filed Apr. 30, 2015).

BACKGROUND

On November 14, 2014, Kentucky Power filed notice of its intent to file an application for approval of an increase in its electric rates based on a historical test year ended September 30, 2014, pursuant to the Stipulation and Settlement Agreement ("Mitchell Settlement") in Case No. 2012-00578.[4] On December 23, 2014, Kentucky Power filed its Application, which included new rates to be effective on or after January 23, 2015, based on a request to increase its electric revenues by approximately $70 million, or 12.48 percent. The Application also requested approval of Kentucky Power's environmental compliance plan and proposed to revise, add, and delete various tariffs applicable to its electric service. 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 June 22, 2015.

The following parties requested and were granted full intervention: Kentucky Industrial Utility Customers, Inc. ("KIUC"); the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG"); Kentucky School Boards Association ("KSBA"); and Wal-Mart Stores East, LLP/Sam's East, Inc. ("Wal-Mart").

On January 13, 2015, the Commission issued a procedural schedule establishing the schedule for processing this case. The procedural schedule provided for discovery, intervenor testimony, rebuttal testimony by Kentucky Power, a formal evidentiary

[4] 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 Nov. 22, 2013).

hearing, and an opportunity for the parties to file post-hearing briefs.[5] Intervenor testimonies were filed on March 23, 2015. Kentucky Power filed its rebuttal testimony on April 29, 2015.

On April 9, 14, and 23, 2015, an informal conference ("IC"), which extended over four days, including the teleconference on April 27, 2015, was held at the Commission's offices to discuss procedural matters and the possible resolution of pending issues. All parties participated in the IC through April 23, 2015.[6] On April 27, 2015, the IC was continued via telephone at which time the parties, with the exception of the AG, arrived at an agreement in principle for the resolution of the issues raised in this case. On April 30, 2015, Kentucky Power, KIUC, and KSBA ("Settling Intervenors") filed a Settlement which addressed all of the issues raised in this proceeding. The AG and Wal-Mart were not signatories to the Settlement. Although Wal-Mart did not sign the Settlement, it filed a sworn statement that it had no objection to the Settlement and that it was unaware of any reason why the Commission should not adopt and approve the Settlement in its entirety. Under the terms of the Settlement, Kentucky Power and the Settling Intervenors agreed to forego cross-examination of each other's witnesses at the evidentiary hearing in this matter. The Settlement is attached as Appendix A to this Order.

Because the Settlement was not unanimous, the evidentiary hearing set for May 5, 2015, convened as scheduled for the purposes of hearing (1) testimony by Kentucky

[5] After establishing the procedural schedule for the evidentiary portion of the case, the Commission scheduled and conducted three public meetings in the service territory of Kentucky Power. The public meetings were held on March 24, 2015, in Hazard; March 25, 2015, in Louisa; and April 16, 2015, in Pikeville.

[6] The AG participated in the IC for part of the day on April 23, 2015, to discuss procedural matters, after which he ended his participation in the IC.

Power in support of the Settlement, and (2) testimony by Kentucky Power and the AG on contested issues related to the amount of the revenue increases sought by Kentucky Power. On June 5, 2015, Kentucky Power, KSBA, KIUC, Wal-Mart, and the AG filed their 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 AG and Wal-Mart, on all issues raised in this case. The major substantive areas addressed in the Settlement are as follows:

- Kentucky Power's electric revenues should be increased by $45.4 million effective June 30, 2015;[7] this amount consists of a base rate revenue decrease of $23.0 million and $68.4 million of additional revenue from four riders contained in the Settlement.
- The establishment of a return on equity of 10.25 percent for the Environmental Surcharge ("ES") Tariff, the Big Sandy Retirement Rider ("BSRR") Tariff, and the Big Sandy Unit 1 Operation Rider ("BS1OR") Tariff;[8]
- Agreement on Kentucky Power's capitalization and gross revenue conversion factor;[9]
- Approval of Kentucky Power's new Environmental Compliance Plan and establishment of baseline levels for Tariff ES;[10]

[7] Settlement, paragraph 1.

[8] *Id.*, paragraph 2.

[9] *Id.*, paragraph 3.

[10] *Id.*, paragraph 4.

o Amendment of Kentucky Power's System Sales Clause ("SSC") Tariff, including increasing the customers' allocation of the customer/Kentucky Power sharing split to 75 percent/25 percent with an annual base of $15,136,000;[11]

o Establishment of Tariff BSRR;[12]

o Establishment of Tariff BS1OR;[13]

o Revisions to and increased funding for Kentucky Power's Distribution Vegetation Management Plan;[14]

o Revision of Kentucky Power's non-distribution depreciation rates and agreement concerning the amortization of certain deferred costs;[15]

o Establishment of an economic development surcharge and matching contribution by Kentucky Power;[16]

o Dismissal of the appeals by Kentucky Power and KIUC from the Commission's January 22, 2015 Order in Case No. 2014-00225;[17] resolution of the no-load cost issue in Case No. 2014-00450, which is currently pending before the Commission;[18] and agreement by Kentucky Power and KIUC concerning the manner in

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[11] *Id.*, paragraph 5.

[12] *Id.*, paragraph 6.

[13] *Id.*, paragraph 7.

[14] *Id.*, paragraph 8.

[15] *Id.*, paragraph 9.

[16] *Id.*, paragraph 10.

[17] Case No. 2014-00225, *An Examination of the Application of the Fuel Adjustment Clause of Kentucky Power Company from November 1, 2013 Through April 30, 2014* (Ky. PSC Jan. 22, 2015).

[18] Case No. 2014-00450, *An Examination of the Application of the Fuel Adjustment Clause of Kentucky Power Company from November 1, 2012 through October 30, 2014* (Initiating Order Feb. 5, 2015).

which no-load costs will be treated following the retirement of Big Sandy Unit 2 (paragraph 11 of the Settlement);[19] [20]

- Amendment of Kentucky Power's Biomass Energy Rider ("BER") Tariff;[21]
- Establishment of deferral mechanisms for PJM Interconnection, L.L.C. ("PJM") costs and North American Electric Reliability Corporation ("NERC") compliance and cybersecurity costs;[22]
- Expansion of the demand-side management ("DSM") based School Energy Manager Program to Kentucky Power's entire service territory and the establishment of a pilot tariff for K-12 schools ("Tariff K-12 School");[23]
- Modification of the Contract Service-Interruptible Power ("CS-IRP") Tariff and the merger of the Quantity Power ("QP") and the Commercial and Industrial Power—Time-of-Day ("CIP-TOD") Tariffs through the establishment of the Industrial General Service Tariff;[24] and
- Increase in Kentucky Power's customer charge for the Residential Service Tariff to $14.00 per month.[25]

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[19] *Id.*, paragraph 11.

[20] A similar side agreement on this issue has been reached by Kentucky Power and the AG, who is not a signatory to the Settlement.

[21] *Id.*, paragraph 12.

[22] *Id.*, paragraph 13.

[23] *Id.*, paragraphs 15-16.

[24] *Id.*, paragraphs 17-18.

[25] *Id.*, paragraph 19(a).

The Settlement addresses several other issues, including revenue allocation, rate design, tariffs, nonrecurring charges and non-rate tariff changes.[26] In addition to the rate and tariff changes described above, Kentucky Power and the Settling Intervenors agree to the modifications of the following tariffs:

- The QP, CIP-TOD, Emergency Curtailable Service—Capacity and Energy, Energy Curtailable Service Rider, and Experimental Real-Time Pricing Tariffs should be removed from Kentucky Power's filed tariffs.

- The Capacity Charge Tariff should be amended to reflect an updated charge and to incorporate an annual true-up mechanism as described in the Direct Testimony of John A. Rogness ("Rogness Testimony").

- The CS-IRP Tariff should be amended to incorporate a new credit rate and to expand the total contract capacity authorized under this tariff as described in the Rogness Testimony.

- The Asset Transfer Rider ("ATR") Tariff should be amended to allow a temporary extension of the asset transfer rider to allow Kentucky Power to recover the full amount of the authorized revenue requirement as described in the Rogness Testimony.

- The Purchase Power Adjustment ("PPA") Tariff should be amended to include a variable to allow Kentucky Power to recover the cost of power purchased

[26] The Commission notes the following three errors that appear in the tariff attached to the Testimony of Ranie K. Wohnhas in Support of the Settlement Agreement ("Wohnhas Settlement Testimony") as Wohnhas Exhibit 3: (1) Page 55 of 176 contains incorrect rates for Medium General Service-Secondary ("MGS-Secondary") customers. The rates for the MGS-Secondary class included in Appendix B to this Order are the rates contained in Exhibit 4 to the Wohnhas Settlement Testimony. (2) Pages 173 and 174, Tariff BSRR, differ from Tariff BSRR filed as Exhibit 6 to the Settlement. (3) It appears that Home Energy Assistance Program ("HEAP") Charge language has been added inadvertently to non-residential tariffs. As the HEAP is charged only to residential customers, it should not appear in non-residential tariffs.

unrelated to forced generation or transmission outages that are calculated in accordance with its peaking unit equivalent methodology as described in the Rogness Testimony. A further amendment should be made to reflect that costs recovered through the tariff shall be subject to periodic review and approval by the Commission.

- The Terms and Conditions should be amended to reflect changes to Kentucky Power's schedule of special or nonrecurring charges as described in the Rogness Testimony.

- The non-rate terms of certain tariffs should be modified or implemented as described in the Rogness Testimony.

- The incidental, non-rate text changes identified in the tariff filed as Exhibit JAR-9 should be implemented.

CONTESTED REVENUE REQUIREMENT ISSUES

In its Application, Kentucky Power proposed an annual increase in its electric revenues of $69,977,002.[27] Through testimony, the AG contends that Kentucky Power should be allowed to increase its electric revenues by $20,454,000. Pursuant to the Settlement, Kentucky Power and the Settling Intervenors agree that, among other things, an annual increase in electric revenues of $45.4 million is reasonable. Since the parties have not reached a unanimous settlement on the increase in revenues, the Commission must consider the evidentiary record on this issue as presented by Kentucky Power and the AG and render a decision based on a determination of Kentucky Power's capital, rate base, operating revenues, and operating expenses as would be done in a fully litigated rate case.

[27] Direct Testimony of Ranie K. Wohnhas ("Wohnhas Testimony") at 5. Kentucky Power's Application included an alternative rate increase amount that included a transmission adjustment that increased its revenue requirement by $126,908.

TEST PERIOD

Kentucky Power proposes the 12-month period ending September 30, 2014, 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, which was a provision of the Mitchell Settlement. The Commission also finds it is reasonable to use the 12--month period ending September 30, 2014, as the test period in the instant case. That 12-month period is the most recent feasible period to use for setting rates based on the timing of Kentucky Power's filing and by virtue of the Mitchell Settlement, and, except for the adjustments approved herein, the revenues and expenses incurred during that period are neither unusual nor extraordinary. 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 $1,556,922,634.[28] 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 its Kentucky jurisdictional capitalization. The jurisdictional ratio uses the test-year-end rate base before any ratemaking adjustments applicable to either Kentucky jurisdictional operations or other jurisdictional operations.

[28] Application, Section V, Exhibit 1, Schedule 4; and Section I at 2. The non-jurisdictional percentage of approximately 1 percent is due to the furnishing of electric service at wholesale to the city of Olive Hill and the city of Vanceburg.

Kentucky Power used a jurisdictional ratio of 99 percent.[29] The Commission has reviewed and agrees with the calculation of Kentucky Power's test-year electric rate base for purposes of establishing the jurisdictional ratio.

Pro Forma Jurisdictional Rate Base

Kentucky Power calculated a pro forma jurisdictional rate base of $1,158,186,514,[30] which reflects the types of adjustments made by the Commission in prior rate cases to determine the pro forma rate base. In arriving at that amount, Kentucky Power, among other things, made adjustments of $398,736,120 to remove the coal related assets at the Big Sandy Generating Station ("Big Sandy").

The AG proposed adjustments to Kentucky Power's proposed rate base in his testimony for three items: 1) Accumulated Deferred Income Taxes–2014 Bonus Tax Depreciation ("ADIT"); 2) Contributions in Aid of Construction ("CIAC"); and 3) Cash Working Capital ("CWC"). With respect to ADIT, the AG recommended that Kentucky Power's rate base be reduced by $23.6 million to reflect the impact of the extension of the 50-percent bonus depreciation provision for federal income tax purposes that became law on December 19, 2014. This had not been reflected in Kentucky Power's Application due to the timing of when the Application was filed. In response to discovery questions, Kentucky Power estimated an increase of $23.6 million to ADIT in order to reflect the impact of the 50-percent bonus depreciation provision.[31] After

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

[30] *Id.*, Section II at 392.

[31] Kentucky Power's responses to KIUC's First Request for Information ("KIUC's First Request"), Item 29; and the AG's Second Request for Information ("AG's Second Request), Item 79.

adjusting for the jurisdictional ratio, the AG's adjustment to reduce rate base on a Kentucky jurisdictional basis for ADIT is $23,346,433.

With respect to the CIAC adjustment, the AG corrected an error in Kentucky Power's Application. Kentucky Power had reflected $909,674 in CIAC as a reduction to rate base. In response to a request for information, Kentucky Power stated that the CIAC collected during the test year totaled $947,995.[32] Therefore, the AG proposed an adjustment which reduces rate base by $37,899 on a Kentucky jurisdictional basis with which Kentucky Power is in agreement.[33]

With respect to CWC, the AG proposed an allowance of $42,844,928 which is approximately $726,000 lower than the $43,570,708 proposed by Kentucky Power in its Application. While indicating a preference for using a lead-lag study, the AG stated that if CWC is to be calculated using the Commission's long-standing 1/8-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.[34]

Kentucky Power does not agree with the proposed reduction in its rate base for ADIT resulting from bonus depreciation. Kentucky Power maintains that the accounting entries that would have been included in its income statement and balance sheet if the 50-percent bonus depreciation were included would have produced equal and off-

[32] Kentucky Power's response to the AG's Second Request, Item 51.

[33] Direct Testimony of Ralph P. Smith ("Smith Testimony") at 30-31.

[34] *Id.* at 32.

setting entries.[35] Also, Kentucky Power states these adjustments would have had no effect on Kentucky Power's capitalization for ratemaking purposes.[36]

With the exception of CWC, the Commission has accepted the AG's proposed adjustments to Kentucky Power's Kentucky jurisdictional rate base. The CWC allowance included in the rate base shown below is based on the adjusted operation and maintenance expenses discussed in this Order, as approved by the Commission. With respect to ADIT and CIAC, the Commission has long held that such items are a reduction in rate base for ratemaking purposes. ADIT is a form of cost-free capital, and as such has historically been removed from rate base for ratemaking purposes. To allow a return on ADIT would in effect allow a double return on the amount of ADIT which violates fundamental ratemaking theory. Therefore, the Commission has concluded that the ADIT resulting from bonus depreciation should be removed from Kentucky Power's rate base. We have determined Kentucky Power's pro forma jurisdictional rate base for ratemaking purposes for the test year to be as follows:

[35] Rebuttal Testimony of Ranie K. Wohnhas ("Wohnhas Rebuttal") at R 3.

[36] *Id.*

Total Utility Plant in Service	$2,094,058,019
Add:	
Materials & Supplies	46,045,697
Prepayments	2,476,841
Cash Working Capital Allowance	43,570,708
Subtotal	$ 92,093,246
Deduct:	
Accumulated Depreciation	689,419,283
Customer Advances	25,377,961
Accumulated Deferred Income Taxes	336,513,939
Contributions in Aid of Construction	37,899
Subtotal	$1,051,349,082
Pro Forma Rate Base	$1,134,802,183

Reproduction Cost Rate Base

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

> the 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 rate-making purposes.

Neither Kentucky Power nor the AG provided information relative to 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 precedents involving Kentucky Power as well as other Kentucky jurisdictional utilities.

CAPITALIZATION

Kentucky Power proposed an adjusted Kentucky jurisdictional capitalization of $1,147,480,328.[37] This amount was the result after recognizing adjustments to exclude

[37] Application, Section II at 392.

certain environmental compliance investments which remain part of the environmental rate base included in Kentucky Power's environmental surcharge mechanism.

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

The AG addressed Kentucky Power's proposed capitalization with adjustments similar to those he proposed for Kentucky Power's rate base. He proposed a jurisdictional capitalization of $1,124,095,996 based upon adjustments to ADIT resulting from bonus depreciation of $23,346,433, an increase in CIAC of $37,899, and the elimination of negative short-term debt in the amount of $30,904,414. Kentucky Power is in agreement with the CIAC and short-term debt adjustments but disagrees with the ADIT adjustment for the same reasons discussed in the Rate Base section of this Order.[38]

The Commission agrees with the AG's proposed adjustments to Kentucky Power's capitalization. Our reasoning for accepting the AG's proposed ADIT adjustment is the same as set out in the Rate Base section of this Order.

REVENUES AND EXPENSES

For the test year, Kentucky Power reported actual net operating income from its electric operations of $106,878,446.[39] Kentucky Power proposed 47 adjustments to revenues and expenses to reflect more current and anticipated operating conditions,

[38] Smith Testimony at 30-31; and Wohnhas Rebuttal at R 2-R 3.

[39] Application, Section IV, Exhibit 1, Schedule 4.

resulting in an adjusted net operating income of $91,334,037.[40] With this level of net operating income, Kentucky Power reported an adjusted test-year revenue sufficiency of $4,696,331.[41]

The AG accepted 39 of Kentucky Power's proposed adjustments to its test-year revenues and expenses, adjustments which are also acceptable to the Commission.[42] A list of the accepted adjustments is contained in Appendix C to this Order.

The AG proposed 13 adjustments to Kentucky Power's operating income relating to: 1) commercial and industrial ("C&I") operating revenue; 2) the amortization of deferred integrated gas combined cycle ("IGCC") costs; 3) the amortization of deferred carbon capture and sequestration ("CCS") FEED study costs; 4) amortization of deferred Carrs site costs; 5) amortization of deferred preliminary Big Sandy flue gas desulfurization ("FGD") costs; 6) the treatment of the parent-company loss allocation ("PCLA"); 7) incentive compensation tied to financial performance; 8) the treatment of stock-based compensation expense; 9) Engage to Gain program costs; 10) the treatment of PJM charges and credits related to Big Sandy; 11) treatment of the Mitchell Plant maintenance expense normalization costs; 12) interest synchronization; and 13)

[40] *Id.*

[41] Kentucky Power's base rate revenue sufficiency consists of a base-rate revenue increase of approximately $39.3 million, excluding Kentucky Power's proposed transmission adjustment, and the elimination of the approximate $44 million to be collected annually under the Asset Transfer Rider (*see* Kentucky Power's response Commission Staff's Second Request for Information ("Staff's Second Request"), Item 96.

[42] Appendix C shows 36 adjustments to revenues and expenses. The Annualization of Employee Related Expense includes the following adjustments: 1) Payroll and Savings Plan Annualized Payroll Expense Adjustment; 2) Changes to Savings Plan Expenses Adjustment; 3) 408 Payroll Taxes Related to the Payroll Adjustment; and 4) 408 Payroll Taxes Related to the Payroll Adjustment–Medicare Tax Expenses Adjustment.

miscellaneous expenses, about which the Commission makes the conclusions listed below.

The AG also opposed Kentucky Power's proposed transmission adjustment, which will be addressed herein. These adjustments, and the discussion and findings thereon, pertain solely to Kentucky Power's base rate revenue requirements. In addition to base rates, Kentucky Power's Application includes a number of proposed riders or surcharges. On the various base rate adjustments, the Commission makes the following conclusions:

Commercial and Industrial Revenue

The AG proposed an adjustment to increase Kentucky Power's C&I operating revenues $1,057,173. The proposed adjustment was based upon the AG's inquiry to Kentucky Power about its communications with its C&I customers regarding actual and anticipated expansion, reductions, or closures, as well as the actual or anticipated effective date of each expansion, reduction or closure.[43] As part of its response to the inquiry, Kentucky Power stated:

> The attached list includes information from customers who have informed the Company of plans to expand operations. The additional load may or may not actually materialize on the effective date. Because of the advanced start date, the specific rate code has not been determined yet, so it is not possible to provide the amount of revenue associated with each project.[44]

[43] Kentucky Power's response to the AG's First Request for Information, Item 331.

[44] *Id.*

Based upon the Commission's requirement that adjustments to the income and expenses of a utility be known and measurable in order to be reflected in its decision, we find that the proposed adjustment should be denied due to its speculative nature.

Amortization of Deferred IGCC Costs

Kentucky Power incurred a total of $1,331,254 in deferred IGCC preliminary engineering and development costs and proposed to amortize such costs over a 25-year period which resulted in an annual increase in operations and maintenance expense of $52,505 on a Kentucky jurisdictional basis. Kentucky Power conducted a feasibility study which was the basis for its determination of whether the Kentucky General Assembly would adopt legislation that would support recovery of the proposed IGCC facility's costs through rates. Kentucky Power maintains that the preliminary costs in support of this facility were prudently incurred and that as a result of the General Assembly's failure to adopt such legislation, the facility became uneconomic.[45]

The AG maintains that the Commission should deny approval of the amortization of the deferred IGCC costs. He opines that since the General Assembly failed to pass the legislation and Kentucky Power had not constructed an IGCC facility, these costs are not related to an asset that is used and useful in the provision of electric service to Kentucky ratepayers, and it should be denied.[46]

The Commission is not persuaded by the AG's arguments. Kentucky electric utilities are required to continually review options for safe, reliable and least-cost power. Kentucky Power's IGCC costs were incurred in order to consider this option as a viable

[45] Wohnhas Testimony at 16.

[46] Smith Testimony at 36-37.

alternative. The Commission finds that Kentucky Power incurred its IGCC costs in good faith, and that we are not bound by a used and useful standard, and that such costs may be recovered through rates. Accordingly, we approve the full amount of the proposed $52,505 adjustment for ratemaking purposes.

Amortization of Deferred CCS FEED Study Costs

As part of its investigation to address emerging environmental regulations, AEP conducted a CCS FEED study at its Mountaineer generating station in West Virginia. AEP contends that because the benefits of the study would be enjoyed by each AEP operating company with coal-fired generation, the costs associated with the study should be allocated among those companies.[47] AEP allocated $872,858 in deferred study costs to Kentucky Power and Kentucky Power has proposed a 25-year amortization of that cost which results in an increase in operations and maintenance expense of $34,425 on a Kentucky jurisdictional basis.

The AG disagrees with Kentucky Power's proposed treatment of such costs for a number of reasons, including 1) the costs associated with the CCS FEED study were incurred prior to the test year; 2) the CCS FEED study was conducted at the Mountaineer facility located in West Virginia, which is not owned by Kentucky Power; and 3) AEP did not complete the full CCS FEED study that was originally intended.[48] Also, the AG pointed out that Kentucky Power stated in response to a request for information that none of the generating plants owned by AEP and its subsidiaries,

[47] Wohnhas Testimony at 16-17.

[48] Smith Testimony at 40.

including Kentucky Power, currently employ any forms of CCS nor are there any plans to employ CCS.[49]

Again the Commission is not persuaded by the AG's arguments. With the myriad of existing and pending environmental regulations, utilities must conduct research and development in order to develop the new or improved technologies necessary to comply with such environmental regulations on a timely basis. Despite the fact that the study was not completed, AEP incurred the study costs in good faith. Accordingly, the Commission finds the amount allocated to Kentucky Power should be allowable for ratemaking purposes. Accordingly, we approve Kentucky Power's proposed adjustment of $34,425 for ratemaking purposes.

Amortization of Deferred Carrs Site Costs

Kentucky Power proposed an adjustment to recover costs associated with its Carrs site development. These costs were incurred for preliminary design and engineering work to support developing a new generation facility at the site. The costs total $2,619,935 and Kentucky Power proposes amortizing them over 25 years, producing an increase in operations and maintenance expense of $103,330 on a jurisdictional basis.

The AG concludes that Kentucky Power's proposed amortization of the Carrs site costs should be removed from the cost of service.[50] He states that:

> these costs were incurred over 30 years ago and there are evidently no records from that time that support these costs nor is it clear that it was actually KPCo that incurred the cost. In addition, the Company has not constructed a generation

[49] *Id.*

[50] Smith Testimony at 42.

> facility at the CARRS site and these costs are not related to an asset that is used and useful in the provision of electric service to Kentucky ratepayers. Moreover, the land, which is not being used to provide electric utility service, may have value and KPCo could sell it. Therefore, the Company's proposed amortization should be rejected.[51]

Kentucky Power did not address the AG's contention in its rebuttal testimony. However, in its original testimony, Kentucky Power stated:

> As part of its long term planning, the Company purchased property (the "Carrs Site") in Lewis County, Kentucky as a potential site for a new generation facility. In addition, the Company conducted preliminary site design and engineering work to support developing the property. The Company has elected not to pursue construction of new generation at the Carrs Site at this time and has removed the land-related costs for this site from rate base. The Company is seeking, however, to recover the engineering and site design costs. The Company prudently incurred these costs as part of its long-term generation resource planning.[52]

The Commission is not persuaded by Kentucky Power's arguments. We note that a Certificate of Public Convenience and Necessity was never requested from the Commission for any project related to the Carrs site property; it is not entirely clear as to what costs were incurred and the purpose for those costs; the costs were incurred more than 30 years ago; and the property has not benefitted Kentucky Power's customers at any time since its acquisition. Accordingly, the Commission denies Kentucky Power's request to recover $103,330 for ratemaking purposes. Further, the Commission directs Kentucky Power to remove the deferred costs of $2,619,935 from its books and charge that amount to expense upon the issuance of this Order.

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[51] *Id.*

[52] Wohnhas Testimony at 17.

Amortization of Deferred Preliminary Big Sandy FGD Costs

Kentucky Power proposed an adjustment to recover costs it incurred for engineering and design work related to potentially installing FGD systems at Big Sandy Unit 2. Kentucky Power is proposing to recover $28,024,682 by amortizing these costs over a 25-year period, or an increase to operations and maintenance expense of $1,105,293 on a Kentucky jurisdictional basis.

The AG opposes Kentucky Power's proposed adjustment to recover the amortization of the Big Sandy FGD preliminary engineering costs as it was addressed by the Commission's removal of paragraph 8 from the Mitchell Settlement. He further states that the recovery of these costs is not reasonable as the study in question did not result in the addition of an FGD system being installed at Big Sandy Unit 2 and that Kentucky Power's proposed adjustment should be rejected.[53]

Kentucky Power maintains recovery should be allowed since:

> In the Stipulation and Settlement Agreement in Case No. 2012-00578, the Company and other settling parties agreed that Kentucky Power would be authorized to treat the Big Sandy FGD Preliminary Engineering costs as a deferred regulatory asset to be recovered over a five year period. In its Order in approving the Mitchell Transfer, the Commission conditioned its approval of the transfer on the Company agreeing to modify the July 2, 2013 Stipulation and Settlement Agreement to delete Kentucky Power's right under the agreement to defer and recover over a five-year period the Big Sandy FGD Preliminary Engineering costs. Contrary to what Messrs. Smith and Kollen claim, neither the Commission's Order in Case No. 2012-00578, nor the Company's acceptance of the modification required by the Order, provided that the Company was precluded from seeking Commission approval to recover the Big Sandy FGD Preliminary Engineering Costs in a future rate proceeding.[54]

[53] Smith Testimony at 44.

[54] Wohnhas Rebuttal at R 5.

In support of its proposed adjustment, Kentucky Power also pointed out the cost savings that resulted from the Mitchell Transfer as compared to retrofitting Big Sandy Unit 2.

The Commission finds that Kentucky Power's proposed adjustment for the amortization of the Big Sandy FGD study costs is unreasonable and should be denied. In its October 7, 2013 Order in Case No. 2012-00578, the Commission determined that those costs were unreasonable and struck that provision from the Mitchell Settlement.[55] Our ruling on that issue was never appealed and thus the determination on the Big Sandy FGD study costs is final and controlling herein. Accordingly, the proposed adjustment of $1,105,293 will be denied for ratemaking purposes. Furthermore, Kentucky Power should remove the deferred asset of $28,024,682 from its books and charge that amount to expense upon the issuance of this Order.[56]

Parent-Company Loss Allocation

The AG proposed a negative adjustment of $516,651 to Kentucky Power's revenue requirement to reflect a reduction in federal income tax expense due to the PCLA. The PCLA occurs when the income tax savings benefit of the tax loss of AEP is allocated to the companies with positive taxable income which participate in the AEP consolidated tax return.[57] In support of its position, the AG stated that the PCLA adjustment has been included in federal income tax expense and approved by the West

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[55] Case No. 2012-00578, *Kentucky Power Company* (Ky. PSC Oct. 7, 2013), Order at 39.

[56] It is the Commission's understanding that Kentucky Power took these actions upon issuance of the October 7, 2013 Order in Case No. 2012-00578. If that understanding is correct, the instruction in this sentence may be disregarded by Kentucky Power.

[57] Kentucky Power's response to KIUC's First Request, Item 21.a.

Virginia Commission in West Virginia rate cases since the early 1990s.[58] Further, the AG states that Kentucky Power has not demonstrated a good reason why the PCLA should be excluded from the determination of Kentucky jurisdictional federal income tax expense.[59]

Kentucky Power reflected the PCLA in its Application on a total-company basis but it did not flow through as a reduction to its Kentucky jurisdictional federal income tax expense. In its filing, it followed past precedent in Case Nos. 2005-00341[60] and 2009-00549[61] and did not include the PCLA in its determination of income tax expense.[62]

The Commission finds that the AG's proposal to include the PCLA in Kentucky Power's federal income tax expense is inappropriate. This recommendation, if adopted, would represent a significant departure from over 25 years of the Commission's established and balanced policy prohibiting affiliate cross-subsidization.[63] Therefore, the "stand-alone" approach the Commission has historically used shall be used to allocate income tax liabilities for Kentucky ratemaking purposes. Accordingly, we deny the AG's proposed adjustment for ratemaking purposes.

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[58] *Id.*

[59] Smith Testimony at 47.

[60] Case No. 2005-00341, *General Adjustments in Electric Rates of Kentucky Power Company* (Ky. PSC Mar. 14, 2006).

[61] Case No. 2009-00549, *Kentucky Power Company* (Ky. PSC June 28, 2010).

[62] Kentucky Power's response to KIUC's First Request, Item 21.c.

[63] *See* Case No. 89-374, *Application of Louisville Gas and Electric Company for an Order Approving an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith* (Ky. PSC May 25, 1990).

Incentive Compensation

Kentucky Power included $3,970,200 of incentive compensation plan ("ICP") costs in its Kentucky jurisdictional revenue requirement.[64] This amount reflects the adjustments made by Kentucky Power in its filing to remove ICP costs related to the Big Sandy generation and the annualization of the Mitchell generation expense.[65]

The AG recommended an adjustment to eliminate 75 percent, or $4,607,841[66] of ICP costs on a Kentucky jurisdictional basis, from rate recovery.[67] As support for his recommendation, the AG notes that Kentucky Power's funding measures for the plan are tied to AEP's earnings per share ("EPS") (75-percent weight), safety (10-percent weight), and strategic initiatives (15-percent weight).[68] He maintains that since Kentucky Power's shareholders are the main beneficiaries of the 75-percent funding measure for EPS, then ratepayers should not be responsible for the ICP costs that are tied to the 75-percent funding measure.[69]

Kentucky Power maintains that the AG's adjustment to its proposed ICP expense is not warranted, arguing that the ICP provides benefits to both Kentucky Power's customers and its shareholders.[70] Kentucky Power states that the expense should be permitted since it is part of the AEP System and Kentucky Power and its employees

[64] Rebuttal Testimony of Jason M. Yoder ("Yoder Rebuttal"), Exhibit JMY – R2 at1.

[65] *Id.* at R 2.

[66] Smith Testimony at 51.

[67] *Id.*

[68] *Id.* at 48.

[69] *Id.* at 50.

[70] Wohnhas Rebuttal at R 13.

benefit from the expertise and the work performed by AEP Service employees to control costs and provide reliable service to all of its customers.[71]

Kentucky Power points out that the AG failed to recognize the adjustments made to remove the ICP costs related to Big Sandy generation expense and the annualization of the Mitchell generation expense, a failure which results in double counting the removal of generation-related ICP.[72] Kentucky Power maintains that the double-counting must be recognized and its effects eliminated if a proposal to remove any portion of Kentucky Power's ICP expense from the cost of service is approved.[73]

The Commission is in general agreement with the AG on this matter after the adjustments described above are made. Incentive criteria based on a measure of EPS, with no measure of improvement in areas such as service quality, call-center response, or other customer-focused criteria are clearly shareholder oriented. As noted in Case No. 2013-00148, the Commission has long held that ratepayers receive little, if any, benefit from these types of incentive plans.[74] It has been the Commission's practice to disallow recovery of the cost of employee incentive plans that are tied to EPS or other earnings measures and we find that Kentucky Power's argument to the contrary does nothing to change this holding as it is unpersuasive.

While the Commission agrees with the AG conceptually, we find that the amount that should be removed for ratemaking purposes should be based on the performance

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[71] *Id.*

[72] Yoder Rebuttal at R 3.

[73] *Id.*, JMY-R2 at 1; On rebuttal, Kentucky provided the calculation showing $2,947,874 as the corrected amount of the AG's adjustment after recognition of the double-counting.

[74] Case No. 2013-00148, *Application of Atmos Energy Corporation for and Adjustment to Rates and Tariff Modifications* (Ky. PSC Apr. 22, 2014), Order at 20.

measures of the plan, not the funding measures. Among the performance measures, only 15 percent is based on financial performance. Accordingly, the Commission's adjustment removes only 15 percent, or $442,181, of the cost of $2,947,874 Kentucky Power provided in rebuttal from test-period operating expenses for ratemaking purposes.

Stock-Based Compensation

Kentucky Power included $1,725,818 in Long-Term Incentive Plan ("LTIP") costs in its Kentucky jurisdictional revenue requirement. Kentucky Power maintains, as with its ICP, that the LTIP is a substantial component of the compensation for the management employees and is critical to maintaining the market–competitiveness of compensation for such employees.[75]

These LTIP plans include Restricted Stock Units ("RSU") and Performance Units ("PU").[76] Neither of these plans has any voting rights nor are they entitled to receive any dividend declared on AEP common stock. However, the RSU's are entitled to additional RSUs (Dividend Equivalent RSUs) of an equal value to dividends paid on AEP common stock.[77] The PUs accrue dividend credits that are generally equal to the value of dividends paid on shares of AEP common stock.[78]

[75] Direct Testimony of Andrew R. Carlin at 31.

[76] Smith Testimony at 52.

[77] *Id.*

[78] *Id.* at 53.

The AG recommended an adjustment of $2,614,851 to remove the LTIP costs in their entirety for ratemaking purposes.[79] As support for his position, the AG states:

> Ratepayers should not be required to pay executive or director compensation that is based on the performance of the Company (or its parent company's) stock price, or which has the primary purpose of benefitting the parent company's stockholders and aligning the interests of participants with those of such stockholders.
>
> Additionally, prior to being required to expense stock options for financial reporting purposes under ASC 718 (Formerly SFAS 123R), the cost of stock options was typically treated as a dilution of shareholders' investments, i.e., it was a cost borne by shareholders. While ASC 718 now requires stock option cost to be expensed on a company's financial statements, this does not provide a reason for shifting the cost responsibility for stock-based compensation from shareholder to utility ratepayers.[80]

Finally, the AG points to Case No. 2010-00036,[81] where the Commission found that with regard to stock-based compensation, the program primarily benefits shareholders and that the expenses associated with the stock-based compensation plan should be denied.

The Commission is in agreement with the AG on this matter. Regarding stock-based compensation, the Commission has consistently held, in the absence of clear and definitive quantitative evidence demonstrating a benefit to ratepayers, that

[79] Yoder Rebuttal, JMY-R3 at 1; As with the ICP costs, this adjustment did not reflect Kentucky Power's adjustments for the Big Sandy and Mitchell generation. With those adjustments recognized, the correct amount is $1,725,818.

[80] Smith Testimony at 53-54.

[81] 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), Order at 34.

ratepayers should not be required to bear the program's cost. Accordingly, we will remove $1,725,818 in LTIP costs for ratemaking purposes.

Engage to Gain Program Costs

The AG proposed an adjustment to remove the Engage to Gain Program costs of $145,421 included in the test year since the program was only in effect for a year and ended in December 2013.[82] Kentucky Power maintains the Engage to Gain program provided an opportunity for employees to submit cost-saving and revenue-enhancing ideas to create sustainable savings to Kentucky Power.[83] Further, Kentucky Power maintains these savings are reflected in the cost of service and that the related costs should be recovered in rates.

The Commission is in agreement with the AG in that Kentucky Power's Engage to Gain Program costs are nonrecurring and should not be allowed as an expense for ratemaking purposes. Accordingly, the Commission will accept the AG's adjustment which denies recovery of $145,421.

PJM Charges and Credits Related to Big Sandy Unit 1

In its filing, Kentucky Power proposed to remove from base rates $4,300,110 of PJM charges and have them recovered through the BS1OR. For purposes of including the PJM charges in the BS1OR, Kentucky Power annualized these costs.[84]

The AG recommended that the PJM charges remain in base rates. The AG claims that Kentucky Power has not justified inclusion of the estimated PJM charges in

[82] Smith Testimony at 55.

[83] Wohnhas Rebuttal at R 14.

[84] Application, Exhibit AEV-4 at 1. Kentucky Power's annualized PJM charges total $5,653,211.

the BS1OR and states that, "Inclusion of PJM charges in the BS1OR could also lead to abuse, as PJM invoices can be quite complicated, and KPCo has not provided a clear audit trail of which exact PJM charges would be included in the Rider versus PJM charges that are recovered elsewhere, such as in base rates."[85]

In its rebuttal, Kentucky Power maintains the PJM charges resulting from operating Big Sandy Unit 1 as a coal plant are properly considered "coal related operating expenses" as contemplated by paragraph 3 of the Commission-approved Mitchell Settlement.[86] Kentucky Power states that:

> [t]hese charges relate to the Company's operation of Big Sandy Unit 1 because they are incurred directly as a result of the MWh of generation produced by Big Sandy Unit 1. Because of this, the PJM charges and credits directly related to Big Sandy Unit 1 should be recovered through the proposed BS1OR.[87]

Kentucky Power also rejects the AG's witness's, Ralph C. Smith, assertion that PJM bills are confusing and difficult to audit and might lead to "abuse."[88] It maintains that the AG's view is an unsupported contention and that, even if accurate, his concern that the bills might be difficult to audit could be easily addressed by moving Big Sandy Unit 1 into a subaccount.[89] Also, Kentucky Power states that, because of the annual BS1OR

[85] Smith Testimony at 67.

[86] Rebuttal Testimony of Alex. E. Vaughn at R 6.

[87] *Id.*

[88] *Id.*

[89] *Id.*

filing requirements, recovering Big Sandy-related operating costs via the BS1OR is particularly transparent.[90]

The Commission concurs with Kentucky Power's proposed treatment of the PJM charges and credits related to Big Sandy Unit 1. The proposed treatment is appropriate and in accordance with paragraph 3 of the Commission-approved Mitchell Settlement. Moreover, Kentucky Power has indicated that it can set up a separate accounting for Big Sandy Unit 1, which should alleviate the AG's concerns about an audit trail.[91] Therefore, Kentucky Power's proposal to remove PJM charges of $4,300,110 from base rates to be recovered in BS1OR is approved.

Mitchell Plant Expense Normalization Costs

Kentucky Power proposed to normalize maintenance expense for the Mitchell Plant by calculating a three-year average of the Mitchell Plant maintenance expense using the 12-month periods ending September 30, 2012, and September 30, 2013, and an annualized amount for 2014, resulting in maintenance expense averaging $15,744,373 for the three-year period. With annualized Mitchell Plant maintenance expense for the test year of $12,474,790, Kentucky Power's proposal results in an increase to operations and maintenance expense of $3,223,809 on a Kentucky jurisdictional basis.

The AG partially agrees with the normalization adjustment but believes a period greater than three years should be used to achieve a better measure for smoothing out any abnormal maintenance costs incurred in a particular year. He recommends a five-

[90] Post-Hearing Brief of Kentucky Power Company at 71.

[91] *Id.*

year period which results in decreasing Kentucky Power's proposed adjustment by $998,577 on a Kentucky jurisdictional basis.[92]

In its rebuttal testimony, Kentucky Power stated that it purposefully chose a three-year period to calculate a plant maintenance normalization adjustment because the past three years reasonably depict the necessary level of plant maintenance to maintain the safe and operable reliability of the Mitchell Plant on an ongoing basis.[93] Further, Kentucky Power states that the AG witness, Mr. Smith, is not an engineer; his testimony is devoid of any relevant experience in the operation of coal-fired steam generating plants; and he bases his recommendation on his belief, unsupported by anything other than his testimony, that "a period of greater than three years provides a better measure for smoothing out any abnormal plant maintenance costs."[94]

The Commission finds that Kentucky Power's proposed adjustment of Mitchell Plant maintenance expense is reasonable and supported by its direct and rebuttal testimony. Accordingly, we will include $3,223,809 in operations and maintenance expense for ratemaking purposes.

Interest Synchronization

The AG proposed an adjustment to modify Kentucky Power's interest synchronization adjustment to: (1) reflect the AG's recommended capitalization; and (2) include the tax deductible interest related to Kentucky Power's accounts receivable

[92] Smith Testimony at 58-59.

[93] Rebuttal Testimony of Jeffrey D. LaFleur at R 2.

[94] *Id.* at R 5.

financing. The result of this adjustment is to increase state and federal income tax by $54,320 and $312,504, respectively.

Kentucky Power did not entirely agree with the AG on this issue. Kentucky Power agrees that its capitalization should be adjusted to set short-term debt at zero and to include an interest calculation for accounts receivable financing but disagrees with the amount of long-term debt used by the AG in his capitalization.[95] Kentucky Power maintains the AG's state and federal income tax result shown above is incorrect due to the reduction in capitalization for bonus tax depreciation.[96]

The Commission finds that the AG's proposal for the interest synchronization adjustment is correct. Kentucky Power's capitalization should be adjusted to reflect the impact on ADIT due to the bonus tax depreciation. Accordingly, an adjustment of $366,824 in additional state and federal income tax will be made for ratemaking purposes.

<u>Miscellaneous Expenses</u>

The AG proposed an adjustment to remove from cost-of-service expenses related to lobbying, tickets to sporting events, employee gifts and awards, membership dues, charitable contributions, and public relations. The total proposed adjustment reduces operation and maintenance expense by $365,132 on a Kentucky jurisdictional basis.

Kentucky Power provided no rebuttal to the AG's proposed adjustment to miscellaneous expenses. However, in response to a request for information from

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[95] Wohnhas Rebuttal at R 5.

[96] *Id.*

Commission Staff, Kentucky Power stated that the miscellaneous expenses in question were inadvertently included in the cost of service and should have been excluded.[97]

The Commission finds that the adjustment proposed by the AG for miscellaneous expenses is reasonable and should be accepted. Accordingly, $365,132 will be removed from operations and maintenance expense for ratemaking purposes.

<u>Transmission Adjustment</u>

In its Application, Kentucky Power proposed that its transmission costs should be based upon the charges it incurs as a load-serving entity ("LSE") under PJM's Open Access Transmission Tariff ("OATT"). Kentucky Power states that such costs, which are included in the proposed PJM rider, would be what Kentucky retail customers pay for transmission service rather than its embedded cost of service.[98] To facilitate such a change, the embedded cost of transmission service and the PJM OATT transmission owner revenues would have to be removed from Kentucky Power's cost of service, and the PJM OATT charges are then the remaining cost for transmission service.

Kentucky Power offered a number of reasons as to why its customers' transmission costs should be based upon the charges under the PJM OATT rather than its embedded cost-of-transmission service. Ultimately, under Kentucky Power's proposal, the rates its customers pay for retail electric service would reflect the cost-of-transmission service that Kentucky Power incurs as their LSE.

The AG disagrees with Kentucky Power's proposed transmission adjustment. He states that the proposal would remove transmission costs from base rates and have

[97] Kentucky Power's response to Commission Staff's Third Request for Information (Staff's Third Request"), Item 45.

[98] Direct Testimony of Alex E. Vaughn ("Vaughn Testimony") at 20.

recovery in a transmission rider.[99] He states the recovery of the transmission cost should continue in Kentucky Power's base rates and that the proposed adjustment, which reduced Kentucky Power's requested revenue requirement by $126,908, is not needed.[100]

The Commission is in agreement with the AG on this issue.[101] The Commission is responsible for ensuring that utilities provide safe and reliable electric service at the least cost. The proposed transmission adjustment would delegate ratemaking authority for transmission service from the Commission to the Federal Energy Regulatory Commission ("FERC") which would increase the cost of transmission service. Further, the proposal is inconsistent under Kentucky law and precedent which give the Commission retail ratemaking authority for vertically integrated utilities.

Net Operating Income Summary

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

Operating Revenues	$570,599,659
Operating Expenses	478,031,053
Adjusted Net Operating Income	$ 92,568,606

RATE OF RETURN

Capital Structure

Kentucky Power proposed an adjusted test-year-end capital structure consisting of 2.69 percent negative short-term debt, 4.52 percent accounts receivable financing,

[99] Smith Testimony at 72.

[100] *Id.*

[101] The transmission adjustment is not included in the Settlement.

52.98 percent long-term debt, and 45.19 percent common equity.[102] The AG recommends an adjusted capital structure for Kentucky Power containing no negative short-term debt, 4.61 percent accounts receivable financing, 51.49 percent long-term debt, and 43.9 percent common equity.[103]

Kentucky Power agreed to eliminate negative short-term debt from its jurisdictional capitalization as suggested by the AG.[104] Kentucky Power disagreed with the AG with respect to the proposed impact of the 50-percent bonus depreciation on rate base and capitalization.[105]

In the Reitter Testimony, he states that, "[d]uring 2014, Kentucky Power both reduced its equity and increased its debt as part of the recapitalization required to restore the Company's debt to capitalization ratio to pre-Mitchell Transfer levels of approximately 54%."[106] This was accomplished by permanently refinancing $265 million of long-term debt[107] associated with the Mitchell Transfer, distributing $155 million in dividends to the parent company, and returning the paid-in capital associated with the Mitchell Transfer Case.[108]

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[102] Direct Testimony of Marc D. Reitter ("Reiter Testimony"), Section V, Exhibit 1, Schedule 2, at 1.

[103] Smith Testimony, Exhibit RCS-1, Schedule D at 1.

[104] Wohnhas Rebuttal at R 2.

[105] *Id.* at R 3.

[106] Reitter Testimony at 4.

[107] Case No. 2013-00410, Application of Kentucky Power Company for Authority Pursuant to KRS 278.300 to Issue and Sell Promissory Notes of One or More Series, to Enter into Loan Agreements, and for Other Authorizations in Connection with the Refunding of Liabilities Assumed by the Company in Connection with the Mitchell Transfer (Ky. PSC Mar. 25, 2014).

[108] Reitter Testimony 5.

The Commission finds that Kentucky Power's capital structure for ratemaking purposes should include no short-term debt, 4.61 percent accounts receivable financing, 51.49 percent long-term debt, and 43.9 percent common equity as proposed by the AG.

Cost of Debt

Kentucky Power proposed costs of short-term debt of .25 percent, accounts-receivable financing of 1.07 percent, and long-term debt of 5.41 percent.[109] The AG recommended that Kentucky Power's cost of debt as proposed in its Application be used by the Commission.[110] Therefore, the Commission finds the cost of short-term debt, accounts-receivable financing, and long-term debt to be 0.25 percent, 1.07 percent, and 5.41 percent, respectively.

Return on Equity ("ROE")

In the Testimony of William E. Avera and Adrien M. McKenzie ("Avera/McKenzie Testimony") Kentucky Power estimated its required ROE using the Discounted Cash Flow model ("DCF"); the Empirical Capital Asset Pricing Model ("ECAPM"), which is a variation of the Capital Asset Pricing Model ("CAPM"); and the Risk Premium ("RP") approach.[111] Based on the results of the methods employed in its analysis, Kentucky Power recommended an ROE range of 9.7 to 11.3 percent, with a midpoint of 10.5 percent. Kentucky Power added a 12-point adjustment for flotation cost, resulting in a recommended ROE of 10.62 percent.[112] Kentucky Power likewise recommended a

[109] *Id.* at 9 and Section V, Exhibit 1, Schedule 2 at 1.

[110] Woolridge Testimony at 19.

[111] Avera/McKenzie Testimony at 4.

[112] *Id.* at 5.

10.62 percent ROE for its environmental compliance-related expenditures.[113] Through settlement negotiations, all the parties except the AG reached an agreement, which is set forth in the Settlement, that an ROE of 10.25 percent should be used for purposes of calculating rates for Tariff ES, Tariff BSRR, and Tariff BS1OR.[114] Otherwise, the Settlement is silent as to ROE.

Kentucky Power employed a comparable risk-proxy group in its analysis which consists of 13 electric utility companies included in *The Value Line Investment Survey*'s ("*Value Line*") electric utility industry group and that have Standard & Poor's Corporation ("S&P") corporate credit ratings of "BBB-," "BBB," or "BBB+," long-term Moody's issuer ratings of "Baa3," "Baa2," or "Baa1," a *Value Line* Safety Rank of "2" or "3;" market capitalization of $2.4 billion or greater; no ongoing involvement in a major merger or acquisition; and no cuts in dividend payments during the last three months.[115] Kentucky Power also applied the DCF model to a proxy group of low-risk non-utility companies followed by *Value Line* that pay common dividends; have a Safety Rank of "1"; have a Financial Strength Rating of "B++" or greater; have a beta of 0.70 or less; and have investment-grade credit ratings from S&P with bonds having ratings of "BBB" and above.[116]

As part of its analysis, Kentucky Power provided a discussion of regulatory mechanisms allowing it to recover fuel and purchased power costs, environmental costs, and DSM costs, which affect its rates for utility service but do not eliminate its risk

[113] *Id.* at 70.

[114] Settlement at 5.

[115] Avera/McKenzie Testimony at 20.

[116] *Id.* at 65.

and do not set it apart from other utility firms, according to Kentucky Power.[117] Kentucky Power indicated that Moody's left its long-term issuer rating unchanged in 2014 when it upgraded the ratings of most electric utilities, and quoted S&P and Moody's statements that Kentucky Power's need for additional capital for maintenance, replacements, and investment in new facilities will require it to seek external funding sources to meet its cash flow needs and to receive additional equity contributions to maintain an appropriate capital structure.[118]

In the Direct Testimony of J. Randall Woolridge ("Woolridge Testimony"), the AG criticized Kentucky Power's ROE estimates on several grounds. The AG's major areas of disagreement with Kentucky Power's DCF analysis, which produced an ROE range of 9.4 to 10.1 percent,[119] were the asymmetric elimination of low-end DCF results, and the "excessive" use of Wall Street analysts' and *Value Line* Earnings Per Share ("EPS") growth rates in developing the growth-factor component, contending that they are overly optimistic and overstated.[120] The AG stated that the primary problems with Kentucky Power's ECAPM analysis, which suggests an ROE range of 11.3 to 12.4 percent,[121] are the use of the ECAPM version of the CAPM; the current and projected risk-free interest rates that are used; the market-risk premium that is computed using an expected market return of 13.1 percent; and the size adjustment that is used.[122] The AG

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[117] *Id.* at 10-11.

[118] *Id.* at 9.

[119] *Id.* at 4.

[120] Woolridge Testimony at 58.

[121] Avera/McKenzie Testimony at 4.

[122] Woolridge Testimony at 63.

disagreed with Kentucky Power's RP approach, which resulted in 10.1 and 11.3 percent equity-cost rates using current and projected utility bond yields respectively,[123] stating that both the base yield and risk premium used are inflated. The AG contends that Kentucky Power's RP equity-cost rates, which are developed by regressing the annual authorized ROEs for electric utilities from 1974 to 2013 on the yields on Moody's long-term utility bonds, overstate actual state-level ROEs authorized by state utility commissions. As a basis of comparison to Kentucky Power's RP equity-cost rates, the AG quotes the Regulatory Research Associates' ("RRA") statistics of allowed average electric utility ROEs, excluding Virginia generation adders of 10.01 percent in 2012, 9.8 percent in 2013, and 9.76 percent in 2014.[124] The AG also recommends against Kentucky Power's proposed adjustment for flotation costs, stating that Kentucky Power has not identified any current flotation costs.

The AG estimated Kentucky Power's required ROE using the DCF model and the CAPM applied to both the AG's electric proxy group as well as Kentucky Power's proxy group. Relying primarily on the DCF model, the AG determined an ROE range of 7.9 to 8.45 percent, and using the upper end of the equity-cost rate recommended an ROE for the proxy groups of 8.4 percent. In recognition of the risk difference between Kentucky Power and the proxy group, the AG recommended that the equity-cost rate be adjusted by .25 percent, resulting in a recommended ROE for Kentucky Power of 8.65 percent.[125]

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[123] Avera/McKenzie Testimony at 4.

[124] Woolridge Testimony at 71-74.

[125] *Id.* at 53-54.

The AG employed in his analysis an electric proxy group consisting of 29 utility companies having at least 50 percent of their revenues from regulated electric operations as reported by *AUS Utilities Reports*; listed as electric utilities by *Value Line* and as an electric or combination electric and gas utility in *AUS Utilities Reports*; having an investment-grade corporate credit and bond rating; having paid a cash dividend for the past six months with no cuts or omissions; not involved in an acquisition in the past six months; and having long-term EPS analysts' growth-rate forecasts available from Yahoo, Reuters, and/or Zack's.[126] As previously mentioned, Kentucky Power's electric proxy group was also included in the AG's analysis.

The AG supported his analysis with a discussion of capital costs in today's markets, and countered the views set out in the Avera/McKenzie Testimony regarding forecasts of higher interest rates and their likely impact on public-utility yields. The AG concluded that capital markets have recovered and that capital costs continue to be at historically low levels with low interest rates and high stock prices.[127] The AG's discussion includes a reference to an exhibit showing the investment risk for 99 industries including electric, water, and gas utilities, indicating that the investment risk of utilities is very low when compared to the other industries as measured by *Value Line* betas.[128]

On rebuttal, Kentucky Power addressed the AG's recommended ROE stating that the recommended 8.65 percent ROE is far below investors' required return and is

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[126] *Id.* at 17.

[127] *Id.* at 16.

[128] *Id.* at 27.

based on an analysis that is downwardly biased. Kentucky Power discussed the importance of being granted an ROE that allows it the opportunity to achieve earnings comparable to those from alternative investments of similar risk. According to Kentucky Power, while the AG noted that the ROE must be comparable to returns investors expect to earn on other investments of similar risk, this fundamental standard was ignored in the AG's estimate of Kentucky Power's required ROE.[129] Kentucky Power quoted a recent FERC opinion which affirmed that its ultimate task is to ensure that awarded ROEs satisfy the requirements of the Supreme Court decisions in the Hope[130] and Bluefield[131] cases, and stated that FERC has made it clear that it is the result reached and not the method used that determines whether an ROE is just and reasonable. Kentucky Power referenced FERC's conclusion that a mechanical Application of the DCF model during times of anomalous capital market conditions could result in an ROE that was insufficient to meet regulatory standards, and that additional record evidence, such as alternative benchmark methodologies and state commission-approved ROEs, should be considered in determining a reasonable ROE.[132]

Kentucky Power stated that the AG's reliance on dividend growth rates and historical growth measures in performing the DCF analysis did not provide a meaningful indication of investors' expectations; that the AG considered analysts' EPS forecasts as being biased and failed to recognize the importance of considering investors'

[129] Rebuttal Testimony of William E. Avera and Adrien M. McKenzie ("Avera/McKenzie Rebuttal Testimony") at 3-4.

[130] Federal Power Commission v. Hope Natural Gas Company, 320 U.S. (1944).

[131] Bluefield Waterworks and Improvement Company v. Public Service Commission. 262 U.S. 679 (1932).

[132] Avera/McKenzie Rebuttal Testimony at 4-5.

perceptions and expectations; that the AG relied upon personal views rather than the capital markets for investors' expectations; and that the AG failed to test the reasonableness of model inputs, including data, in its analysis that leads to illogical conclusions.[133]

Kentucky Power recommended that the AG's CAPM analysis be disregarded, noting that the AG gave primary weight to its DCF analysis. Kentucky Power states that the AG's criticisms of its RP analysis is inaccurate, and addressed the AG's claims regarding allowed ROEs not reflecting investors' expectations, and that regulators have routinely authorized ROEs greater than what investors require. Kentucky Power discussed the AG's argument that current interest rates indicate that investors have low expectations of capital cost, and stated that highly regarded forecasts indicate a clear consensus in the investment community that the cost of long-term capital will be significantly higher over the 2015-2019 period.[134] Kentucky Power recommended that the AG's electric proxy group be rejected due to flaws in the screening criteria and data used in its establishment. Kentucky Power also reiterated on rebuttal the need for a flotation cost adjustment in its ROE calculation, stating that it is supported by financial literature and that there is no basis to ignore such an adjustment.

Having considered the evidence in the record, the Commission finds an ROE of 9.8 percent to be reasonable, within a range of 9.3 to 10.3 percent that we also consider to be reasonable. In reaching our finding, we have excluded adjustments for flotation cost and have given considerable weight to analysts' projections in the Application of

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[133] *Id.* at 18.

[134] *Id.* at 50-51.

the DCF model. During the May 5, 2015 Hearing in this proceeding, Kentucky Power's ROE witness, Mr. Avera, and the AG's ROE witness, Mr. Woolridge, were cross-examined concerning the previously-mentioned information from RRA regarding average-authorized ROEs for electric utilities from state regulatory commissions. The average-authorized ROEs with and without Virginia awards, which include ROE premiums for generation projects, were 10.02 and 9.8 percent, respectively, in 2013; 9.91 and 9.76 percent, respectively, in 2014; and for the first quarter of 2015 were 10.37 and 9.67 percent, respectively. As stated in the final Order in Case No. 2013-00148,[135] while this Commission does not rely on returns awarded in other states in determining the appropriate ROE for Kentucky jurisdictional utilities, it is reasonable to expect that other state commissions, each with their own attributes, are evaluating expert witness testimony which uses the same or similar cost-of-equity models and reaching conclusions based on the data provided in the records of individual cases. The conclusions reached by those commissions as well as this Commission as to reasonable ROEs are summarized periodically by RRA with explanatory reference points and made available to investors. To the extent that investors' expectations are influenced by such publications, we believe it is appropriate to use that information to put their expectations in context and that our findings as to a reasonable ROE for Kentucky Power will not appear unreasonable.

Rate-of-Return Summary

Applying the rates of 5.41 percent for long-term debt, 1.07 percent for accounts-receivable financing, and 9.8 percent for common equity to the capital structure

[135] Case No. 2013-00148, *Atmos Energy Corporation* (Ky. PSC April 22, 2014), Order at 29.

produces an overall cost of capital of 7.14 percent. The cost of capital produces a return on Kentucky Power's rate base of 7.07 percent.

BASE RATE REVENUE REQUIREMENTS

The Commission has determined that, based upon Kentucky Power's capitalization of $1,124,095,996 and an overall cost of capital of 7.14 percent, Kentucky Power's net operating income that could be justified by the evidence of record is $80,260,454. Based on the adjustments found reasonable herein, Kentucky Power's pro forma net operating income for the test year is $92,568,606. Therefore, Kentucky Power would need a decrease in annual base rate operating income of $12,308,152. After the provision for uncollectible accounts, the PSC Assessment, and state and federal income taxes, Kentucky Power would have a base rate electric revenue sufficiency of $19,895,192.

The calculation of this base rate revenue sufficiency is as follows:

Net Operating Income Found Reasonable	$80,260,454
Pro Forma Net Operating Income	92,568,606
Net Operating Income Sufficiency	$12,308,152
Gross Revenue Conversion Factor	1.616424
Base Rate Revenue Sufficiency	$ 19,895,192

This base rate revenue sufficiency compares to the base rate decrease of $23.0 contained in the Settlement.

The reasonableness of the Settlement increase of $45.4 million is discussed later in the Total Jurisdictional Revenue Requirements section.

REVENUE REQUIREMENT-RELATED RIDERS AND DEFERRALS

This section contains discussion and analyses of various riders, or surcharges, proposed by Kentucky Power, which are considered to be part of its overall revenue requirement.

Big Sandy Retirement Rider

Pursuant to paragraphs 3 and 14 of the Mitchell Settlement, Kentucky Power proposes to recover 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 the proposed BSRR.[136] In accordance with the Mitchell Settlement, the costs are to be recovered over a 25-year period on a levelized basis including a weighted-average cost-of-capital ("WACC") carrying cost. Kentucky Power calculated an annual revenue requirement for the BSRR of $21,855,982 using actual and estimated retirement costs.[137] The AG contested the use of estimated future costs in calculating the BSRR annual revenue requirement amount and stated that the carrying costs included in the revenue requirement were excessive. After making adjustments to remove estimated costs and adjusting the net book value used in the calculation, the AG recommended an initial BSRR annual revenue requirement of $11.114 million.[138]

On rebuttal, Kentucky Power referred to the Wohnhas Testimony for the reasons why it is appropriate to include estimated costs in determining the BSRR annual revenue requirement. In addition, Kentucky Power criticized the AG for not using

[136] The rider was referred to as "Asset Transfer Rider-2" in the Mitchell Settlement.

[137] Wohnhas Testimony at 7 and the Direct Testimony of James M. Yoder at 15.

[138] Smith Testimony at 63.

updated information in his calculation which was provided by Kentucky Power during discovery, and related to accumulated deferred incomes taxes and the WACC. Using the updated information and excluding estimated costs, Kentucky Power calculated a BSRR annual revenue requirement of $15.578 million using the AG's proposed WACC.[139]

The Settlement provides that no estimated costs shall be included in the calculation of the BSRR revenue requirement and sets an initial annual revenue requirement of approximately $16.7 million, or $5.2 million less than that proposed in the Application.[140] Under the Settlement, actual Big Sandy retirement-related costs incurred subsequent to June 30, 2015, will be deferred as they are incurred and added to the unamortized balance of the BSRR regulatory asset. Although the initial rate will be in effect for approximately 15 months, the Settlement sets forth that the BSRR rates will be adjusted annually with the first annual filing to be made beginning on or before August 15, 2016, and each August 15 thereafter to be effective with the cycle 1 October billing cycle each year.[141] The AG states in his Post-Hearing Brief that he does not object to most of the basic structure of the BSRR as set forth in the Settlement; however, he opposes the use of an ROE of 10.25 percent for the BSRR. He argues that an ROE of this level would result in rates that are not fair, just, or reasonable.

[139] Rebuttal Testimony of James M. Yoder at 9.

[140] $21.9 million – $5.2 million = $16.7 million. *See* Wohnhas Settlement Testimony at 19. The reduction in the annual revenue requirement from that included in the Application is due to the exclusion of estimated costs, the agreed reduction from 10.62 percent to 10.25 percent of the return on equity used in computing the WACC, and Kentucky Power's acceptance to use no negative short-term debt in computing the initial capitalization and resulting WACC.

[141] The information to be included in the annual filings is set forth in paragraph 6(e) of the Settlement.

Based on our earlier finding that a 9.8 percent ROE is a reasonable return for Kentucky Power in this matter, we have determined the revenue requirement for the BSRR to be $16.5 million. As the 9.8 percent ROE is the mid-point of a range of 9.3 to 10.3 percent that the Commission considers reasonable, and the 10.25 percent ROE reflected in the Settlement falls within that range, we find the use of the 10.25 percent ROE to be reasonable for purposes of settlement.

Big Sandy Unit 1 Operation Rider

As part of the Mitchell Settlement, Kentucky Power agreed to remove from the cost of service in its next base-rate case, all coal-related operating expenses related to Big Sandy Unit 1.[142] Therefore, Kentucky Power proposes that a rider be established 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 a return on and of the capital investment required for its conversion to natural gas once it is placed in service. The rider, BS1OR, would be in effect only until the rates established in Kentucky Power's next base rate case are implemented. At that time, the BS1OR would be discontinued as the Big Sandy Unit 1 operating costs would then be recovered through base rates. Kentucky Power calculated an initial annual revenue requirement of $18,245,413,[143] which included non-fuel operation and maintenance expenses and an annual level of Big Sandy Unit 1 PJM charges and credits. Kentucky Power proposed that the BS1OR revenue requirement and billing factors be adjusted annually and filed with the Commission 10 days before they are scheduled to go into

[142] Mitchell Settlement, paragraph 3.

[143] Vaughn Testimony at 19.

effect, along with all necessary supporting data. However, Kentucky Power did not provide a specific date by which the filing would be made each year.

The Settlement allows for the implementation of the BS1OR as proposed. Testimony filed in support of the Settlement states that the rider permits Kentucky Power to demonstrate the removal of all Big Sandy coal-related costs from base rates in a transparent manner and avoids the necessity of filing a base-rate case following the conversion of Big Sandy Unit 1 to a natural gas-fired generating unit.[144]

In his Post-Hearing Brief, the AG stated that he had no objection with the terms of the BS1OR as set forth in the Settlement with two exceptions. He reiterated his objection to including PJM costs in the BS1OR and argued that the stated ROE for this rider should be set at a level of 8.65 percent.[145]

As previously discussed in this Order, the Commission has rejected the AG's position on the inclusion of PJM costs in the BS1OR. The Commission also notes that Kentucky Power committed to establishing a separate PJM subaccount for Big Sandy Unit 1 costs at the Hearing in this proceeding.[146] As with the BSRR, given that the Commission considers a range of 9.3 to 10.3 percent to be a reasonable range for Kentucky Power's ROE, we find the 10.25 percent ROE used in the Settlement to be reasonable for purposes of settlement given that it falls within that range. The Commission finds the BS1OR to be a reasonable method for recovery of the Big Sandy Unit 1 operating costs removed from the cost of service and will approve this portion of

[144] Wohnhas Settlement Testimony at 20.

[145] AG's Post-Hearing Brief at 32.

[146] May 5, 2015 Hearing Video at 18:11:15.

the Settlement, but finds that when Kentucky Power files its compliance tariff for the BS1OR, it should include the date by which it will make its annual filing each year.

Kentucky Economic Development Surcharge

In its Application, Kentucky Power proposed to collect from all customers an economic development surcharge of $0.15 per meter per month[147] in order to fund economic development initiatives in Kentucky Power's service territory. All amounts collected through the surcharge would be matched equally by Kentucky Power from shareholder funds. It is expected that the surcharge would generate a total of $615,014 annually, including amounts contributed by shareholders.[148]

Kentucky Power contends that an increase in economic activity and additional jobs will result from the expenditure of these funds and that the increased economic activity will strengthen communities' tax bases which will help to support schools and other local government-provided services. Kentucky Power also argues that by growing its service territory economy, it will grow its load and customer base which will allow costs to be spread over a greater number of kWhs and customers, and would therefore aid in keeping the cost to individual customers as low as possible.[149]

In the Smith Testimony, the AG recommended removal of the economic development surcharge stating that it was not needed, has not been justified, and that such expenditures should not receive special surcharge treatment. The AG criticized Kentucky Power for not identifying specific projects to be funded by the surcharge and

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[147] The charge would not apply to the outdoor lighting class.

[148] Rogness Testimony at 17.

[149] *Id*. at 19.

noted that Kentucky Power is currently committed to continue shareholder-provided funding via the Kentucky Power Economic Advancement Program through 2018, but that Kentucky Power has not made a decision concerning shareholder funding for that program beyond 2018.[150]

In rebuttal testimony, Kentucky Power contends that the need for the economic development surcharge is evidenced by the January 13, 2014 Final Report presented to Governor Steve Beshear and Congressman Hal Rogers in connection with the Shaping Our Appalachian Region ("SOAR") initiative.[151] Kentucky Power states that the January 13, 2014 Final Report shows a lack of economic development in eastern Kentucky and notes a 43.1 percent loss of coal jobs in the 54-county SOAR area due to coal companies closing or reducing size.[152] Kentucky Power claims that unemployment is a major problem in its service territory and that the current $200,000 shareholder contribution for the Kentucky Power Economic Advancement Program is not sufficient in that those funds target only Lawrence County and contiguous counties surrounding Lawrence County. Finally, Kentucky Power argues that the lack of specific identified projects that will benefit from the economic development surcharge funds is necessary in order to provide as much flexibility as possible.

Recognizing that Kentucky Power's service territory has some of the highest unemployment rates in the state, the AG stated in his Post-Hearing Brief that he supports economic development but prefers that the total economic development funds be provided by Kentucky Power's shareholders. The AG also states that, alternatively,

[150] Smith Testimony at 71.

[151] Rebuttal Testimony of John A. Rogness at 2.

[152] *Id.*

he does not object to the economic development surcharge as set forth in the Settlement.

The Commission recognizes that Kentucky Power's service territory includes many of the most economically deprived counties in the Commonwealth. Considering the economic needs of this service area, Kentucky Power's history and expertise in economic development, and its current commitment of shareholder funds to this effort, the Commission finds the proposed economic development surcharge to be reasonable and it should be approved. Kentucky Power should work closely with SOAR, and its economic development efforts and expenditures should be coordinated with the SOAR initiative in its service territory. Finally, the Commission urges Kentucky Power to extend beyond the current 2018 commitment its shareholders' financial support for the Economic Advancement Program, which is specifically for Lawrence County and the surrounding contiguous counties.

<u>TOTAL JURISDICTIONAL REVENUE REQUIREMENTS</u>

The Commission has found that Kentucky Power's required ROE falls within a range of 9.3 percent to 10.3 percent, with a mid-point of 9.8 percent. Applying the findings herein regarding the reasonable cost of debt and common equity to Kentucky Power's capitalization would result in a justifiable revenue increase, including riders, of approximately $46.8 million. The alternative proposal provided in the Settlement is $45.4 million. The Settlement amount is based upon a base rate revenue sufficiency of approximately $23 million coupled with the riders proposed in the Settlement. The $45.4 million revenue increase Kentucky Power is willing to accept will result in fair, just, and reasonable electric rates for Kentucky Power and its ratepayers. Therefore, the

Commission will accept Kentucky Power's alternative proposal that its revenues be increased by $45.4 rather than the higher level justified by the record.

NONREVENUE REQUIREMENT RIDERS AND TARIFF

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.

Tariff SSC

Kentucky Power's current Tariff SSC was set at zero pursuant to the Mitchell Settlement until new base rates are set by the Commission. In its Application, Kentucky Power proposed to update the system sales margin amount included as a credit to the annual revenue requirement. In addition, Kentucky Power proposed to maintain the same 60/40 customer sharing mechanism that was in place prior to the Mitchell Settlement. The total amount proposed to be credited to customers through base rates in the Application was approximately $14.3 million.[153]

The AG opposed Kentucky Power's 60 percent (customer)/40 percent (Kentucky Power) sharing mechanism and recommended a 90/10 sharing mechanism. The AG claimed that Kentucky Power's customers are paying for the fixed costs of Kentucky Power's generation and should receive a larger share of any off-system sales margins.

In its rebuttal testimony, Kentucky Power claims that the 60/40 sharing mechanism reasonably and equitably addresses the customer contribution while allowing Kentucky Power a reasonable incentive to maximize off-system sales.[154] Kentucky Power also points out that increasing the customer percentage also increases

[153] Vaughn Testimony, Exhibit AEV-7.

[154] Wohnhas Rebuttal at 7.

customer risk. Although a 90/10 sharing mechanism would provide customers with additional margins when margins exceeded the monthly base amount, it would require customers to assume the risk of paying additional amounts when margins fell below the monthly base amount.[155]

Under the Settlement, effective with the first billing cycle of July 2015, Tariff SSC would be approved as filed in the Application except that: 1) the annual baseline amount would be $15,136,000; and 2) any difference, either positive or negative, between each month's actual margins and the baseline will be shared 75 percent (customers)/25 percent (Kentucky Power). The Settlement specifies that the monthly off-system sales margin baseline amount includes, and monthly actual off-system sales margins shall be calculated utilizing, the methodology for allocating no-load costs described in the Settlement.

The AG states in his Post-Hearing Brief that he has no objection to the proposed revisions to the SSC Tariff as set forth in the Settlement.

Given that Kentucky Power had a SSC mechanism in place for more than 20 years prior to the Mitchell Settlement, the Commission views the establishment of a new Tariff SSC favorably. Accordingly, we find that the revised Tariff SSC contained in the Settlement is reasonable and that it should be approved.

PJM Costs

In its Application, Kentucky Power proposed a new rider to recover certain PJM charges and credits that it incurs from its participation as a load-serving entity and generation-resource owner in PJM. Kentucky Power proposed to include a specified test-year level of charges and credits in base rates and then track the PJM charges or

[155] Wohnhas Rebuttal at R 7- R 8.

credits above or below the base level. The annual net over or under collection would be collected from, or credited to, customers through the proposed PJM rider. Kentucky Power argued that PJM charges and credits can have a material effect on its financial operations and are largely out of its control. Kentucky Power also claimed that tracking PJM charges and credits through a rider could reduce the frequency of general rate proceedings.[156]

The Settlement does not provide for such a rider but instead allows Kentucky Power to defer PJM costs in excess of the amount included in base rates under certain conditions. If Kentucky Power's calendar-year ROE falls below 10 percent, the Settlement specifies that Kentucky Power would be authorized to defer for future recovery through the establishment of a regulatory asset only the portion of PJM costs in excess of $74,856,675 (the amount of PJM costs included in base rates) required to increase the ROE for the calendar year to 10 percent. Any amounts that would increase Kentucky Power's ROE to more than 10 percent are not to be deferred.[157] The Settlement states that Kentucky Power is prohibited from recording a carrying charge or earning a return on any amounts deferred.

In his Post-Hearing Brief, the AG states that he has no objection to the PJM deferral mechanism as set forth in the Settlement and recommends the Commission approve it. However, the Commission is not convinced that these costs have reached a level of uncertainty or volatility that would require the establishment of a deferral mechanism. The Commission believes that costs of this nature are more appropriately

[156] Vaughn Testimony at 16.

[157] Wohnhas Settlement Testimony at 36.

recoverable through base rates. Therefore, the Commission rejects this portion of the Settlement.

NERC Compliance and Cybersecurity Costs

In its Application, Kentucky Power proposed a new rider to track and defer the capital and operation and maintenance expense costs associated with compliance and cybersecurity activities for new requirements or new interpretations of existing requirements of NERC. Kentucky Power proposed that any capital-related costs deferred include carrying costs at Kentucky Power's WACC. The Application stated that Kentucky Power would request recovery of the deferred NERC costs through this proposed rider in a subsequent proceeding, at which time the Commission would review the costs for prudency.

The Settlement does not include a rider to recover NERC costs but allows Kentucky Power to track and defer any post-June 30, 2015 incremental costs incurred in complying with new NERC compliance and cybersecurity requirements. Subject to Commission review and approval, Kentucky Power would be allowed to recover and amortize these costs over five years beginning when the Commission sets base rates in the next base-rate case. Kentucky Power agreed in the Settlement to make an informational filing each year on or before March 31 quantifying and describing the amounts deferred.

The AG states in his Post-Hearing Brief that, while he does not object to the terms of the Settlement related to this issue, he recommends that when these costs are before the Commission for review and approval, the Commission consider the concerns set forth by KIUC in this proceeding through the Direct Testimony of Lane Kollen.

The Commission will approve the deferral costs incurred for new NERC requirements, but puts Kentucky Power on notice that any future request to recover such costs much be supported by showing a direct relationship between the costs incurred and the new NERC requirements. Kentucky Power will have to provide substantial evidence that a nexus exists between the new NERC requirements and the incremental costs incurred.

Tariff BER

Kentucky Power has a BER included in its current tariff which will be charged to customers when Kentucky Power begins purchasing power under the Renewable Energy Purchase Agreement approved by the Commission in Case No. 2013-00144.[158] In its Application filed in the instant case, Kentucky Power did not propose any changes to its Tariff BER. However, the Settlement includes a revision to the Tariff BER in that total charges to be recovered would include an energy charge and a demand, or non-energy, charge. The current tariff provides for only an energy charge per kWh. Under the Settlement, the energy charge would be determined using the PJM AEP Zone Locational Marginal Price. The demand charge would be the difference between the energy charge and the total annual charges and would be charged to non-residential customers based on a percentage of non-fuel revenues. For residential customers, the total charges would continue to be based on the energy usage recorded at the customers' meters. A residential customer would pay the same amount under the current and revised Tariff BER.

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[158] Case No. 2013-00144, *Application of Kentucky Power Company for Approval of the Terms and Conditions of the Renewable Energy Purchase Agreement for Biomass Energy Resources Between the Company and ecoPower Generation-Hazard LLC; Authorization to Enter into the Agreement; Grant of Certain Declaratory Relief; and Grant of All Other Required Approvals and Relief* (Ky. PSC Oct. 10, 2013).

In his Post-Hearing Brief, the AG stated that he has no objection to the terms of the Settlement related to this issue. The Commission finds the changes to Tariff BER to be reasonable and that they should be approved.

RATE DESIGN, TARIFFS, AND OTHER ISSUES

Residential Customer Charge

In its Application, Kentucky Power proposed an increase in the residential customer charge from $8.00 to $16.00. The cost-of-service study filed by Kentucky Power in this proceeding supports a customer charge of $39.88.[159] The Settlement allows for an increase in the residential customer charge to $14.00, an increase of $6.00 from the current customer charge of $8.00.

Although the AG did not file testimony on this issue, he objects to an increase in the residential customer charge in his Post-Hearing Brief. The AG argues that the increase set forth in the Settlement is not consistent with the principle of gradualism. He references the unanimous settlement agreement filed in Case Nos. 2014-00371[160] and 2014-00372[161] in which Kentucky Utilities Company and Louisville Gas and Electric Company agreed not to increase the residential customer charge, which for each is currently set at $10.75. The AG recommends that the Commission not allow an increase in Kentucky Power's residential customer charge. In the alternative, if the Commission believes an increase is justified, the AG states that an increase from $8.00

[159] Vaughn Testimony, Exhibit AEV-2 at 1.

[160] Case No. 2014-00371, *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates* (filed Nov. 26, 2014).

[161] Case No. 2014-00372, *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates* (filed Nov. 26, 2014).

to $11.00 would be more consistent with the principle of gradualism than the increase to $14.00 included in the Settlement.

While the Commission believes that some increase in the residential customer charge is warranted, it does not accept an increase to $14.00 as set forth in the Settlement. Within rate classes, when determining the allocation of a rate increase, the Commission has long employed the principle of gradualism. In this instance, we find that allocating a portion of the increase to the residential customer charge to a level of half that set out in the Settlement, and allocating a greater portion to the energy charge, is in keeping with that principle. Therefore, we find that the residential customer charge should be increased to $11.00 instead of the $14.00 contained in the Settlement. [162]

Consistent with this change, the Commission will also modify the customer charges 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. Using a method similar to that used for determining the monthly customer charge for the residential service class, the Commission will approve a customer charge of $13.60 for these classes instead of the $16.65 set forth in the Settlement. Commensurate with the decreases to the customer charges from the levels included in the Settlement, energy rates have been increased to allow Kentucky Power to collect the approved Settlement increase of $45.4 million.

[162] While we have approved increased customer charges for a number of distribution cooperatives in order to provide for greater recovery of fixed costs through the fixed-charge component of customers' bills in order to offset lost revenues due to enlarged and enhanced DSM programs, the Commission notes that Kentucky Power's level of DSM activity has not increased significantly and that it recovers its lost revenues through its DSM surcharge.

Tariff PPA

Kentucky Power proposed certain text changes to its tariff as part of its Application. One of the modifications proposed is a text change to Tariff PPA. The modification would allow Kentucky Power to recover power purchases in excess of its peaking unit equivalent[163] each month through the revised PPA. The Commission has previously disallowed recovery of costs in excess of a utility's highest-cost generating unit, or in excess of the peaking unit equivalent for Kentucky Power, through the fuel adjustment clause ("FAC"), stating that such costs, so long as they are reasonable, were recoverable through base rates.

The Settlement includes the modification proposed in the Application, but also includes an additional text change to the PPA Tariff which states that costs recovered through the PPA shall be subject to periodic review and approval by the Commission.

Kentucky Power stated in discovery that during the years 2010-2013, it did not exclude any purchased power costs from recovery through the FAC due to the peak unit equivalent limitation because of the availability of energy from the AEP East System Pool ("AEP Pool").[164] Kentucky Power also stated that it did not reduce purchased power expenses in the test year, because it recovered all the fuel expenses during the test year[165] but that during 2014, it did not recover $655,017 of purchased power costs

[163] Because Kentucky Power was unique in that it owned no combustion turbines, it was granted authority by the Commission in 2002 to use the peaking unit equivalent approach to calculate the level of non-economy purchased power costs to recover through the FAC. The peaking unit equivalent was based on the operating characteristics of a General Electric simple-cycle gas turbine.

[164] Kentucky Power's response to Staff's Third Request .Item 23.b.

[165] Kentucky Power's response to Staff's Second Request, Item 58.b.

due to the peaking unit equivalent limitation.[166] The fact that the agreement with the AEP Pool is now terminated means that Kentucky Power is on the same footing as the other jurisdictional generating utilities in Kentucky which do not have a mechanism for recovering such costs on a monthly basis. Further, Kentucky Power has not shown that the amounts of these excluded purchased power costs are volatile to the point of requiring this method of recovery. In addition, the Commission notes that there would be numerous administrative issues involved in establishing periodic proceedings to review and approve or deny these costs. The Commission believes these costs are more appropriately recoverable through base rates and will not approve this portion of the Settlement.

Nonrecurring Charges

The Settlement provides for the approval of increases to Kentucky Power's nonrecurring charges including its reconnection charges, returned-check charge, and meter-test charge, as proposed in the Application and set forth in Appendix B to this Order. Kentucky Power's nonrecurring charges were last adjusted in 2006 in Case No. 2005-00341.[167] The Commission finds the increases to Kentucky Power's nonrecurring charges to be reasonable and that they should be approved.

Tariff ATR

Kentucky Power's tariff currently includes an Tariff ATR which allows for the recovery of $44 million annually as set forth in the Mitchell Settlement. The current Tariff ATR states that the tariff will end when the Commission sets new base rates for

[166] *Id.*, Item 23.b.

[167] Case No. 2005-00341, *Kentucky Power Company* (Ky. PSC Mar. 14, 2006).

Kentucky Power that include the costs of Mitchell Units 1 and 2. In its Application, Kentucky Power proposed to modify the tariff language to allow it to recover its pro rata share (computed on a 365-day annual basis) of the annual $44 million in 2015.[168] The Settlement accepts these changes to the ATR Tariff.

The Commission finds the changes to Tariff ATR to be reasonable and that they should be approved.

Fuel Cost Allocation Methodology

Upon approval of the Settlement, Kentucky Power and KIUC agree to withdraw and dismiss with prejudice their pending appeals of the Commission's Order in Case No. 2014-00225.[169] By separate agreement, the AG, KIUC, and Kentucky Power have agreed that the AG shall withdraw and dismiss with prejudice his appeal in consideration of Kentucky Power withdrawing and dismissing its appeal. Kentucky Power also agrees that it shall not recover any Mitchell no-load costs during the period January 1, 2014, through May 31, 2015 ("Overlap Period"). KIUC agrees to withdraw the joint testimony of Lane Kollen filed in Case No. 2014-00450. Following the end of the Overlap Period, the Settlement allows Kentucky Power to allocate fuel costs as it has done historically, as described in paragraph 11(e) of the Settlement.

Given that the retirement of Big Sandy Unit 2 will result in a significant decrease in Kentucky Power's reserve margin and the proposed off-system sharing mechanism under the Settlement is 75/25 with 75-percent sharing to customers, the Commission accepts this portion of the Settlement.

[168] Rogness Testimony at 35-36.

[169] Case No. 20141-00225, *Kentucky Power Company* (Ky. PSC Jan. 22, 2015).

In testimony filed in support of the Settlement and at the Hearing, Kentucky Power requested that, with the first FAC filing made subsequent to this Order, the Commission direct Kentucky Power to initiate refunds of Mitchell no-load costs for the period May 1, 2014, through October 31, 2014, that have been collected by Kentucky Power but not yet refunded to customers.[170] The amount of the total refund for that period is $17,877,704.95.[171] The Commission finds that this request should be granted and that, for the first six FAC filings made subsequent to the date of this Order, Kentucky Power shall credit $2,979,617.49 to customers through the FAC.

ENVIRONMENTAL COMPLIANCE PLAN

As part of this proceeding, Kentucky Power filed an application, pursuant to KRS 278.183, seeking Commission approval of an amended Environmental Compliance Plan ("2015 Plan")[172] and to amend its environmental surcharge Tariff ES. Kentucky Power's current compliance plan is the plan as approved in Case No. 2006-00307 ("2007 Plan").[173] Kentucky Power states that the proposed 2015 Plan is necessary to reflect fundamental changes in Kentucky Power's environmental projects and in its generation portfolio since its 2007 Plan was approved by the Commission.[174]

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[170] Wohnhas Settlement Testimony at 30-31. *Also see* May 5, 2015 Hearing Video at 11:52:45.

[171] Case No. 2014-00450, *Kentucky Power Company* (Initiating Order Feb. 5, 2015), Kentucky Power's response to the Commission's Request for Information, Item 41.

[172] Kentucky Power's Application and witness testimony refers to the environmental compliance plan as the 2014 Plan. In prior environmental compliance plan Orders, the Commission has named the plan according to the year in which the Order is issued approving the environmental compliance plan. Accordingly the Commission will refer to the subject environmental compliance plan as the 2015 Plan.

[173] Case No. 2006-00307, *The Application of Kentucky Power Company for Approval of an Amended Compliance Plan for Purposes of Recovering Additional Costs of Pollution Control Facilities and to Amend Its Environmental Cost Recovery Surcharge Tariff* (Ky. PSC Jan. 2, 2007).

[174] Application at 15.

KRS 278.183(1) provides that a utility shall be entitled to the current recovery of its costs of complying with the Federal Clean Air Act ("CAA") as amended and those federal, state, or local environmental requirements that apply to coal combustion wastes and by-products from facilities utilized for the production of energy from coal. Pursuant to KRS 278.183(2), a utility seeking to recover its environmental compliance costs through an environmental surcharge must first submit to the Commission a plan that addresses compliance with the applicable environmental requirements. The plan must also include the utility's testimony concerning a reasonable return on compliance-related capital expenditures and a tariff addition containing the terms and conditions of the proposed surcharge applied to individual rate classes. Within six months of submission, the Commission must conduct a hearing to:

1. Consider and approve the compliance plan and rate surcharge if the plan and rate surcharge are found reasonable and cost-effective for compliance with the applicable environmental requirements;

2. Establish a reasonable return on compliance-related capital expenditures; and

3. Approve the Application of the surcharge.

Kentucky Power's original compliance plan and environmental surcharge were approved by the Commission in 1997 in Case No. 1996-00489.[175] The original compliance plan ("1997 Plan") was comprised of five projects at the Big Sandy generating station, and three projects at generating stations owned by members of the

[175] Case No.96-489, *Application of Kentucky Power Company d/b/a American Electric Power to Assess a Surcharge Under KRS 278.183 to Recover Costs of Compliance with the Clean Air Act and those Environmental Requirements which Apply to Coal Combustion Waste and By-Products* (Ky. PSC May 27, 1997).

AEP Pool.[176] Kentucky Power's first amendment to its compliance plan and environmental surcharge was approved by the Commission in 2003 in Case No. 2002-00169.[177] The first amendment to the compliance plan ("2003 Plan") was comprised of four projects at Big Sandy Units 1 and 2. Kentucky Power's second amendment to its compliance plan and environmental surcharge was approved by the Commission in 2005 in Case No. 2005-00068.[178] The second amendment to the compliance plan ("2005 Plan") sought to include Kentucky Power's member load ratio share of environmental compliance costs associated with 53 projects at AEP Pool locations owned by Ohio Power and I&M generating stations. Kentucky Power's third amendment to its compliance plan, the 2007 Plan, and environmental surcharge was approved in Case No. 2006-00307.[179] The third amendment sought to include its member load ratio share of environmental compliance costs associated with 44 projects located at Ohio Power and I&M generating stations.[180]

[176] The AEP East–System Pool agreement was terminated effective January 1, 2014. AEP member companies that participated in the AEP Pool were Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company (I&M"), Kentucky Power, and Ohio Power Company ("Ohio Power").

[177] Case No. 2002-00169, *The Application of Kentucky Power Company d/b/a American Electric Power for Approval of an Amended Compliance Plan for Purposes of Recovering the Costs of New and Additional Pollution Control Facilities and to Amend Its Environmental Cost Recovery Surcharge Tariff* (Ky. PSC Mar. 31, 2003).

[178] Case No. 2005-00068, *Application of Kentucky Power Company for Approval of an Amended Compliance Plan for Purposes of Recovering Additional Costs of Pollution Control Facilities and to Amend Its Environmental Cost Recovery Surcharge Tariff* (Ky. PSC Sept. 7, 2005, rehearing Oct. 17, 2005).

[179] Case No. 2006-00307, *Kentucky Power Company* (Ky. PSC Jan. 24, 2007).

[180] Projects at the Mitchell Plant, formerly part of Ohio Power, were among those approved for the Ohio Power locations in the 2005 and 2007 Plans, and are now included in the 2015 Plan. Kentucky Power acquired an undivided 50-percent interest in Mitchell effective December 31, 2013.

THE 2015 COMPLIANCE PLAN

Kentucky Power's 2015 Plan reflects changes to the current 2007 Plan due to changes in its generation portfolio, as well as changes in individual projects. The changes include:[181]

- Effective December 31, 2013, Kentucky Power acquired an undivided 50-percent interest in Ohio Power's Mitchell generating station located in Moundsville, West Virginia;
- The January 1, 2014 termination of the AEP Pool;
- The planned retirement of Big Sandy Unit 2 no later than June 1, 2015;
- The planned conversion of Big Sandy Unit 1 to natural gas by June 30, 2016; and
- Planned environmental projects at I&M's Rockport ("Rockport") generating station.

In the 2015 Plan, Kentucky Power is seeking to include the environmental compliance costs associated with 18 projects located at the Mitchell and Rockport generating stations. The 2015 Plan includes projects that were previously approved in Kentucky Power's original compliance plan and the 2005 and 2007 Plan amendments for the Mitchell and Rockport generating stations. In addition, the 2015 Plan includes projects at Mitchell and Rockport that were installed since approval of the 2007 Plan and the costs associated with Cross-State Air Pollution Rule ("CSAPR") allowances. The 2015 Plan includes the following projects at Mitchell and Rockport that have been installed since the 2007 Plan was approved, or are currently in progress:

[181] Direct Testimony of Amy J. Elliott ("Elliott Testimony") at 3-4.

Mitchell Units 1 and 2:

- o Precipitator modifications;
- o Bottom ash and fly ash handling;
- o Mercury monitoring equipment;
- o Dry fly ash conversion;
- o Coal combustion waste landfill; and
- o Electrostatic precipitator upgrade (Unit 2).

Rockport Units 1 and 2:

- o Precipitator modifications;
- o Activated carbon injection and mercury monitoring;
- o Dry sorbent injection; and
- o Coal combustion waste landfill upgrade to accept Type 1 ash.

At the time of the filing the instant case, two projects at Mitchell were in progress with planned in-service dates in 2015.[182] Likewise, the 2015 Plan includes two projects at Rockport that were not complete at the time of this filing and that have planned in-service dates of 2015.[183] The 18 projects included in the 2015 Plan are listed in Appendix D of this Order.

With the termination of the AEP Pool, Kentucky Power no longer incurs costs for pool-related environmental projects and does not include pool-related environmental costs for recovery in its monthly environmental surcharge filings. Previously-approved

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[182] Elliott Testimony at 7. The Mitchell projects with 2015 in-service dates are the next phase of coal combustion waste landfill and electrostatic precipitator upgrade for Unit 2.

[183] *Id*. at 9. The Rockport projects with 2015 in-service dates are portions of the coal combustion waste landfill upgrade and dry sorbent injection for Units 1 and 2.

projects at the Mitchell and Rockport generating stations billed to Kentucky Power under the AEP Pool are included in the 2015 Plan as noted above.

Kentucky Power removed previously-approved environmental projects at its Big Sandy generating stations from the 2015 Plan with the exception of emission allowances. Because of the planned conversion of Big Sandy Unit 1 to natural gas by June 30, 2016, Kentucky Power is proposing to recover all costs associated with Big Sandy Unit 1 through the BS1OR. The BS1OR would recover all of the operations and maintenance expenses for Big Sandy Unit 1, including those costs which would otherwise be recovered through the environmental surcharge. Due to the planned retirement of Big Sandy Unit 2 by June 1, 2015, to comply with the Mercury and Air Toxics Standards ("MATS") Rule, Kentucky Power removed the Big Sandy Unit 2 projects it previously recovered through the environmental surcharge.[184]

Kentucky Power states that the pollution control projects included in the 2015 Plan are necessary for Kentucky Power to comply with the CAA and other federal, state, and local regulations which apply to coal combustion wastes and by-products from facilities utilized for the production of energy from coal. Kentucky Power contends that the costs associated with its 2015 Plan are reasonable and that the projects are reasonable and cost-effective means to comply with environmental requirements.[185] The Commission finds that the projects proposed by Kentucky Power to be included in the 2015 Plan are reasonable and cost-effective for environmental compliance and should be approved.

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[184] Kentucky Power retired Big Sandy 2 in May 2015.

[185] Application at 17.

ENVIRONMENTAL REQUIREMENTS

Clean Air Interstate Rule ("CAIR") and CSAPR

The CAIR and CSAPR are regional rules that set standards for the emission of sulfur dioxide ("SO_2") and nitrogen oxides ('NO_x") from electric generating units.[186] Phase 1 of CSAPR will effectively replace CAIR in 2015. Under both rules, the United States Environmental Protection Agency ("EPA") establishes emission budgets for each state and SO_2 and NO_x allowances are allocated to emitting units. The allowances permit holders to emit one ton of the covered pollutants and are traded regionally. Kentucky Power records emission allowances on a per-company basis and carries them on an average-cost basis.[187] The allowances are allocated to Kentucky Power by the EPA at zero cost, but subsequent prices are determined by the market for specific allowances with other electric generating units.[188] Whether Kentucky Power will need to purchase additional allowances will be determined by the generation output of pollutants and the sufficiency of allocated allowances.

MATS

The MATS Rule creates environmental requirements for coal- and oil-fired electric generating units regarding the emission of the hazardous air pollutants ("HAPs") of mercury; non-mercury metals such as arsenic, lead, cadmium, and selenium; acid gases, including hydrochloric acid; and many organic HAPs.[189] While MATS is being reviewed by the Supreme Court, the rule will remain in effect; a ruling is expected by the

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[186] Direct Testimony of John M. McManus ("McManus Testimony") at 4.

[187] Elliott Testimony at 6 and 10.

[188] *Id.* at 12.

[189] McManus Testimony at 6.

end of June 2015. Compliance was required by April 16, 2015, with a 45-day extension available. Mercury monitoring equipment and activated carbon-injection systems are necessary for MATS compliance at the Mitchell and Rockport units and will be installed and upgraded under the 2015 Plan. The closure of Big Sandy Unit 2 and the conversion of Big Sandy Unit 1 to a natural gas-fired generating facility were precipitated by the MATS compliance deadline.[190]

Consent Decree

Kentucky Power's generating units are subject to requirements imposed by the Consent Decree entered by the United States District Court for the Southern District of New York in an action arising under the CAA, *United States v. American Electric Power Service Corp.*, Civil Action C2-99-1250, and all modifications thereto (the "Consent Decree").[191] The Consent Decree outlines emission control and monitoring standards, schedules compliance for SO_2, NO_x, and particulate matter for Kentucky Power's generating units, and stipulates penalties for noncompliance. The Third Joint Modification of the Consent Decree authorized the retirement of Big Sandy Unit 2 and the installation of dry sorbent injection equipment at both Rockport units instead of the previously-required installation of FGD equipment by these three units.[192]

TARIFF ES MODIFICATIONS

Kentucky Power proposed several changes to its Tariff ES to reflect the changes in its generation portfolio and compliance plan. Kentucky Power proposed to eliminate

[190] Direct Testimony of Gregory G. Pauley at 4.

[191] Application at 11.

[192] McManus Testimony at 7, and Exhibit JMM-2.

the zero percent surcharge factor authorized by the Commission per the Mitchell Settlement which involved Kentucky Power's acquisition of a 50-percent undivided interest in the Mitchell Plant.[193] Tariff ES is updated to reflect the rate of return authorized in the Settlement in the instant case. Kentucky Power is updating the list of projects in the tariff to match the projects included in the 2015 Plan as noted previously in this Order. Also, Tariff ES is updated to reflect the monthly base environmental costs as set forth in Exhibit 4 to the Settlement. The annual base revenue-requirement level for environmental-cost recovery is $34,902,677. Per the Mitchell Settlement, all costs associated with the Mitchell FGD equipment are to be excluded from base rates and are not included in the base revenue requirement noted above, but will be included in the current-period environmental revenue requirement.[194] Tariff ES is also modified to reflect the change in the revenue allocation and environmental-surcharge factor calculations so that the environmental-surcharge factor for non-residential customers will be calculated as a function of non-fuel revenues. Kentucky Power will continue to calculate the environmental-surcharge factor for residential customers as a function of total revenues. The environmental-surcharge factor calculation is consistent with the Mitchell Settlement.[195] The Commission finds that Tariff ES, as provided for in paragraph 4 of the Settlement and as discussed and modified in this Order, should become effective for service rendered on and after the date of this Order.

[193] Mitchell Settlement, paragraph 5.

[194] *Id.*, paragraph 6.

[195] *Id.*

SURCHARGE MECHANISM AND CALCULATION

Costs Associated with the 2015 Plan

Kentucky Power's surcharge mechanism determines the environmental-surcharge revenue requirement by comparing the base-period revenue requirement with the current-period revenue requirement. Kentucky Power has proposed to incorporate the costs associated with the 2015 Plan into the existing surcharge mechanism used for previous compliance plans. Kentucky Power has identified the environmental compliance costs for the 2015 Plan projects and these are the costs that Kentucky Power proposes to recover through its environmental surcharge. The costs identified here 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 2015 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 earlier, the qualifying costs included in Kentucky Power's annual baseline level for environmental cost recovery under Tariff ES are $34,902,677.[196] The qualifying costs included in the current-period revenue requirement will reflect the Commission-approved environmental projects from Kentucky Power's 1997, 2003, 2005, 2007 and 2015 Plans. Per the Mitchell Settlement, all costs associated with Mitchell Units 1 and 2 FGD equipment have been excluded from both base rates and

[196] Settlement, paragraph 4.

the environmental baseline level and should be recovered exclusively through Tariff ES.[197] 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

Per paragraph 2 of the Settlement, Kentucky Power is authorized a 10.25-percent ROE that will be utilized in Tariff ES to determine the WACC.[198] 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.[199]

Capitalization and Gross Revenue Conversion Factor

Per paragraph 3, Exhibits 2 and 3 of the Settlement, Kentucky Power should utilize a WACC of 7.34 percent and a gross revenue conversion factor ("GRCF") of 1.616424 in determining the rate of return to be used in its monthly environmental surcharge filings. The WACC reflects no short-term debt. The WACC and GRCF should remain constant until such time as the Commission sets base rates in Kentucky Power's next base-rate case proceeding.[200]

Surcharge Formulas

The inclusion of the 2015 Plan in Kentucky Power's existing surcharge mechanism will result in changes to the surcharge formulas. The costs associated with Big Sandy will be excluded from Tariff ES. The costs previously charged to Kentucky Power under the AEP Pool agreement will be excluded from Tariff ES, except those

[197] *Id.*

[198] *Id.*, paragraph 2.

[199] Elliott Testimony at 15.

[200] Settlement, paragraph 3.

projects at Mitchell and Rockport that are now included in the 2015 Plan as noted previously in this Order. 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.[201] 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.[202]

Monthly Reporting Forms

The inclusion of the 2015 Plan in 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 on May 18, 2015.[203] The revised forms include the changes necessary to reflect the proposed 2015 Plan, as well as changes necessitated by the removal of the Big Sandy environmental projects, termination of the AEP Pool Agreement, and the proposed

[201] Elliott Testimony at 16.

[202] Elliott Testimony at 15.

[203] Kentucky Power's supplemental response to Staff's Second Request, Item 37.

methodology for allocating the environmental revenue requirement among customer classes. 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 herein since they will result in a slightly lower rate increase than justified by our traditional ratemaking analysis. Our approval of the Settlement, as modified herein, is based solely on its reasonableness and does not constitute precedent on any issue except as specifically provided for therein.

OTHER ISSUES

Vegetation Management

Kentucky Power's current Distribution Vegetation Management Plan ("Vegetation Plan") was approved as part of a Unanimous Settlement Agreement ("Unanimous Settlement")[204] in Kentucky Power's last base-rate case.[205] As part of that Unanimous Settlement, Kentucky Power agreed to expand its Distribution Vegetation Management Plan ("Vegetation Management Plan"), which required a $10 million increase in expenditures. With this addition, total annual Vegetation Management Plan expenditures increased to $17,237,965.[206] The aim was for Kentucky Power to

[204] Unanimous Settlement by and among Kentucky Power; the AG; KIUC; Community Action of Kentucky, Inc.; Wal-Mart; Hazard Perry County Ministries, Inc.; and KSBA, May 19, 2010.

[205] Case No. 2009-00459, *Kentucky Power Company* (Ky. PSC June 28, 2010).

[206] *Id.*

transition from a reactive performance-based plan to a four-year clearing cycle. Kentucky Power estimated that it would take seven years to transition to the four-year trim cycle.[207] Kentucky Power's 2015 Distribution Vegetation Management Plan ("2015 Vegetation Plan") was submitted to the Commission on September 30, 2014 and presented in the Phillips Testimony, Kentucky Power's Managing Director of Distribution Region Operations. The 2015 Vegetation Plan identifies two obstacles Kentucky Power encountered in the initial plan. First, Kentucky Power found that it had significantly underestimated the amount of vegetation in and around its energized facilities and that the 12.47-kV circuits required significantly more time to clear than originally projected. Second, Kentucky Power found that it took much longer than originally anticipated to safely and productively increase the vegetation management workforce to full staffing levels.[208] As a result of these two obstacles, as stated in the Phillips Testimony, Kentucky Power now estimates it will take eight-and-a-half years to complete the re-clearing instead of the seven years originally estimated.[209] In its current Application, Kentucky Power is requesting approval for additional annual reliability spending of $10,655,900.[210] Kentucky Power further projects that the clearing of every circuit will be completed by the end of 2018, instead of the mid-2017.[211]

[207] *Id.* Kentucky Power Company 2010 Distribution Vegetation Management Plan (filed May 20, 2010) in conformity with paragraph 5.c. of the Unanimous Settlement Agreement, at 2.

[208] 2015 Distribution Vegetation Management Plan (filed Sept. 30, 2014).

[209] Phillips Testimony at 3.

[210] *Id.* at 31.

[211] 2015 Distribution Vegetation Management Plan, Scenario 3 at 8.

In paragraph 8 and 8(a) of the Settlement, Kentucky Power notes that on July 1, 2015, the current Vegetation Management Plan will be replaced with its new 2015 Plan. Kentucky Power agrees to implement Scenario 2 as described in Phillips Testimony, further modified by Kentucky Power's response to a request for information,[212] and as illustrated in Exhibit 9 of the Settlement. As reflected in Exhibit 9 of the Settlement, Kentucky Power is to spend approximately $22.3 million in 2015, $27.7 million beginning 2016-2018, and $21.5 million in 2019. Beginning July 1, 2019, Kentucky Power projects implementing a five-year maintenance clearing cycle, at which time it will reduce Vegetation Management Plan expenditures to approximately $16 million. Exhibit 9 of the Settlement shows that Kentucky Power will continue with this expenditure level for its vegetation plan through 2023.[213]

Kentucky Power anticipates adhering to the Vegetation Management Plan as filed, yet it recognizes situations may arise which require altering expenditures as they relate to system reliability. Paragraph 8(e) of the Settlement addresses Kentucky Power's intent, during the four-year Vegetation Management Plan periods, from July 1, 2015, to June 30, 2019, to adhere to projected annual spending levels of $27,661,060, cumulatively summing to $110,640,240. If it annually spends less than or more than this amount, the annual shortfall or excess will balance against the cumulative four-year sum ending July 1, 2019. At that time, Kentucky Power will record a cumulative shortfall as a regulatory liability which 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

[212] Kentucky Power's response to Staff's Third Request, Item 7.

[213] Settlement, Exhibit 9, Scenario 2 on 5 yr Cycle Revised on 4/20/2015.

overspent on a cumulative basis during the four-year period, it will not seek recovery of such costs in a future base-rate case proceeding.[214]

As Kentucky Power reaches the five-year maintenance clearing cycle around July 1, 2019, the Settlement provides for a reduction in base rates. As stated in paragraph 8(f) of the Settlement, beginning with cycle 1 of the July 2019 billing cycle, and until Kentucky Power's new base rates are established in the first base-rate case after June 30, 2019, Kentucky Power will reduce base retail rates for tariff classes with primary and secondary service offerings by $11,780,408.[215] The Commission expects Kentucky Power to timely and accurately submit this tariff filing.[216]

Paragraph 8(e)(i) of the Settlement states:

> Kentucky Power may alter its proposed spending as detailed in its annual September 30 filing upon discovery of a more pressing need for Distribution Vegetation Management expenditures relating to system reliability purposes. Kentucky Power shall notify the Commission in writing within 30 days of any material deviation from the work plans filed in connection with this subparagraph.

The Commission accepts this provision of the Settlement with the condition that Kentucky Power must seek prior-Commission approval before altering any proposed spending that deviates by 10 percent or more from the total amount or within each Division as set forth in an annual filing on September 30.

As the Commission stated in Kentucky Power's last base-rate case Order,[217] the Commission will again closely review the annual work plans and expenditures Kentucky

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[214] *Id.*, paragraph 8(e).

[215] *Id.*, paragraph 8(f).

[216] *Id.*

[217] Case No. 2009-00459, *Kentucky Power Company* (Ky. PSC June 28, 2010).

Power will be filing. In addition, the Commission will monitor the progress of the clearing work to verify the progression toward a five-year maintenance cycle. As set forth in paragraph 8(d)(vi) of the Settlement, the Commission expects Kentucky Power to be diligent in reporting and fully explaining any unanticipated problems or its inability to complete a material portion of the planned work on a circuit.

<u>Mitchell Plant Transfer/Ash Pond Costs</u>

As part of the Mitchell Plant Transfer, Kentucky Power acquired, in addition to the other assets, a 50-percent interest in the ash ponds at the Conner Run Impoundment. As a result, Kentucky ratepayers are responsible for 50 percent of the costs associated with the operation of the ash ponds. The AG maintains that if a serious ash pond spill should occur there, similar to the one that occurred at Duke Energy's North Carolina plant, it should be understood that Kentucky Power's shareholders, and not the Kentucky ratepayers, would be responsible for the related fines and remediation cost.[218]

In support of his position, the AG pointed to the transfer in 2014 of the remaining 50-percent undivided interest in the Mitchell generation station by AEP Generation Resources Inc. ("AEPGR") to Wheeling Power Company, which excluded to 50-percent interest in the Conner Run Impoundment. As part of the Mitchell Settlement, Wheeling Power Company paid $20 million to AEPGR and the establishment and recovery of a $20 million regulatory asset to be included in Wheeling Power Company's base rate that approximated AEPGR's book value of Conner Run.

Kentucky Power does not agree with the AG's position on this matter. Kentucky

[218] Smith Testimony at 75.

Power points out that, in Case No. 2012-00578,[219] the Commission authorized it to assume all assets and liabilities associated with the Mitchell generating station.[220] Further, the facility has been, and will continue to be, used to provide service to Kentucky Power's customers until sometime in 2015 when Mitchell fly ash and coal combustion residuals, along with cooling tower blow down will no longer be deposited there.[221] In addition, Kentucky Power is currently in discussions with Consolidation Coal Company ("Consolidation Coal") to transfer ownership of the impoundment to Consolidation Coal contemporaneously with Kentucky Power's cessation of use of the impoundment.[222] Kentucky Power states the AG's witness, Mr. Smith, provides no principled explanation why hypothetical personal-injury or property-damage liability associated with its ownership of the Conner Run facility, with respect to an event that Mr. Smith only speculates might occur sometime in the future, should be treated any differently than Kentucky Power's hypothetical liability with respect to any of the assets acquired through the Mitchell Settlement.[223]

While the Commission may share some of the AG's concerns, it does not agree with the AG on this matter. Kentucky Power acquired a 50-percent interest in the Mitchell generating station which required it to assume all assets and liabilities associated with the Mitchell Settlement. As to Kentucky Power's liability associated with a scenario such as the AG has described, the facts and circumstances surrounding

[219] Case No. 2012-00578, *Kentucky Power Company* (Ky. PSC Oct. 7, 2013).

[220] Wohnhas Rebuttal at R 14-R 15.

[221] *Id.* at 15.

[222] *Id.* Additionally, an IC was held with Commission Staff and Intevenors on March 31, 2015, to discuss Kentucky Power's plans for the Conner Run Impoundment.

[223] *Id.*

such an occurrence would have to be known before a decision could be reached as to what, if any, liability Kentucky ratepayers would have. For the Commission to address such a scenario in this Order would be speculative and premature.

Rockport Plant Unit Power Sales Agreement ("Sales Agreement") – Return on Equity of 12.16 Percent

Kentucky Power has a FERC-approved Sales Agreement with AEP Generating Company ("AEGCO") under which it receives 30 percent of the output and is charged 30 percent of the costs of the Rockport plant. In the test year, the total charges were approximately $118.2 million, including $68.8 million for fuel (account 5550046) and $43.4 million for non-fuel (account 5550027) charges.[224] AEGCO receives a 12.16-percent ROE under the terms of the Sales Agreement. Any purchaser, state regulatory commission having jurisdiction over the retail rates of purchasers under the agreement, or other entity representing customers' interest may file a complaint with FERC with respect to the specified ROE.

The AG recommends that the Commission and any other parties that are concerned that the 12.16-percent ROE being used as the basis for charges to Kentucky Power in this affiliated contract is excessive address the matter before FERC as soon as possible. In addition, he recommends the Commission also consider establishing an affiliate Charge-ROE-Reduction Rider for Kentucky Power in order to flow back to ratepayers the impact of the cost reductions to Kentucky Power that could be achieved by having the 12.16-percent ROE in the affiliated contract reduced by FERC. The AG also recommends that the Commission require Kentucky Power to present an accounting of the return-of-common equity portion of the AEGCO charges to Kentucky

[224] Smith Testimony at.79.

accounting of the return-of-common equity portion of the AEGCO charges to Kentucky Power that are related to an ROE reduction, and to report on any refunds from AEGCO to Kentucky Power related to such a reduced affiliated contract ROE.[225]

The Commission finds that the AG's recommendations to address at FERC the 12.16 ROE being used in the Sales Agreement and the establishment of an affiliate Charge-ROE-Reduction Rider should be denied. As with the Commission, FERC is mandated to set rates that are fair, just, and reasonable. While the Commission may not agree with the manner in which FERC establishes ROE, we take note that the terms of a FERC-approved contract have been found to legally constitute a fair, just, and reasonable rate. We also note that FERC's methods of setting an ROE have withstood prior challenges.

Under the terms of the Sales Agreement, the AG has the same authority as the Commission to file a complaint with FERC to address the ROE, should it chose to do so.

ORDERING PARAGRAPHS

The Commission, 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 Agreement, as set forth in Appendix A hereto, are approved, subject to the modifications and deletions set forth in this Order.

3. Within seven days of the date of this Order, the President of Kentucky Power shall file written notice with the Commission indicating whether Kentucky Power

[225] *Id.* at 82.

accepts and agrees to be bound by the modifications to the Stipulation as set forth in Appendix B to this Order.

4. The rates and charges for Kentucky Power, as set forth in Appendix B hereto, are the fair, just, and reasonable rates for Kentucky Power, and these rates are approved for service rendered on and after June 30, 2015.

5. Kentucky Power shall establish a separate PJM subaccount for Big Sandy Unit 1 costs no later than July 1, 2015.

6. Kentucky Power's request to amortize its deferred IGCC costs is approved.

7. Kentucky Power's request to amortize its deferred CCS FEED study costs is approved.

8. Kentucky Power's request to amortize its deferred Carrs site costs is denied.

9. Kentucky Power's request to amortize its deferred preliminary Big Sandy FGD costs is denied.

10. Kentucky Power's 2015 Environmental Compliance Plan is approved.

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

12. The environmental base-period and current-period revenue requirements shall be calculated as described in this Order.

13. 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.

14. The Commission approves the draft forms that were provided by Kentucky Power at the May 28, 2015 IC and revised as filed on June 5, 2015.[226]

15. For the first six FAC filings made subsequent to the date of this Order, Kentucky Power shall credit $2,979,617.49 to customers through the FAC.

16. Within 20 days of the date of this Order, Kentucky Power shall, using the Commission's electronic Tariff Filing System, its revised tariffs setting out the rates authorized herein and reflecting that they were approved pursuant to this Order. Kentucky Power shall include in its Tariff BS1OR, the date by which it will make its annual filing each year.

By the Commission

ENTERED
JUN 22 2015
KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Executive Director

[226] The forms presented at the May 28, 2015 IC were included in the June 1, 2015 IC Memorandum and are available at: http://psc.ky.gov/pscscf/2014%20cases/2014-00396//20150601_PSC_IC%20Memo.pdf. The BS1OR Forms were revised on June 5, 2015, in Kentucky Power's supplemental response to Staff's Third Request, Item 33.

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2014-00396 DATED JUN 22 2015

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The 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)	Case No. 2014-00396

SETTLEMENT AGREEMENT

This Settlement Agreement, made and entered into this 30th day of April, 2015, by and among Kentucky Power Company ("Kentucky Power"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); and Kentucky School Boards Association ("KSBA") (collectively Kentucky Power, KSBA, and KIUC are "Signatory Parties").

WITNESSETH:

WHEREAS, on December 23, 2014 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, seeking an annual increase in retail electric rates and charges totaling $69,977,002, seeking approval of its 2014 Environmental Compliance Plan, and further seeking authority to implement or amend certain tariffs; and

WHEREAS, KIUC and KSBA filed motions for full intervention in P.S.C. Case No. 2014-00396. The Commission granted the intervention motions. Collectively the KIUC and KSBA are referred to in this Settlement Agreement as the "Settling Intervenors;"

WHEREAS, the Attorney General, Commonwealth of Kentucky filed a motion to intervene. The Attorney General, who is not a party to this agreement, also was granted leave to intervene; and

WHEREAS, Wal-Mart Stores East, LP and Sam's East, Inc. ("Wal-Mart") filed a motion to intervene and were granted full intervention. Although not a signatory to this agreement, Wal-Mart has indicated it intends to file a statement in the record indicating that it has no objection to the Settlement Agreement, and that it is unaware of any reason the Commission should not adopt and approve this Agreement in its entirety;

WHEREAS, certain of the Settling Intervenors, Wal-Mart, and the Attorney General in P.S.C. Case No. 2014-00396 filed written testimony raising issues regarding Kentucky Power's Rate Application;

WHEREAS, Kentucky Power, the Attorney General, Wal-Mart, and the Settling Intervenors have had a full opportunity for discovery, including the filing of written data requests and responses;

WHEREAS, Kentucky Power offered the Settling Intervenors, Wal-Mart, 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;

WHEREAS, by Order dated August 31, 2014, the Commission initiated Case No. 2014-00225 to review of the operation of Kentucky Power's fuel adjustment clause during the period November 1, 2013 through April 30, 2014. KIUC and the Attorney General were granted leave to intervene in Case No. 2014-00225, took discovery, filed testimony, and participated fully in Case No. 2014-00225;

WHEREAS, the Commission on January 22, 2015 entered its Order in Case No. 2014-00225;

WHEREAS, Kentucky Power (Civil Action No. 15-CI-00168), the Attorney General (Civil Action No. 15-CI-00180), and KIUC (Civil Action No. 15-CI-00190) filed appeals to the

Franklin Circuit Court challenging aspects of the Commission's January 22, 2015 Order in Case No. 2014-00225. In addition, KIUC and the Attorney General each filed counterclaims in Kentucky Power's appeal (Civil Action No. 15-CI-00168) raising in that action the issues raised in their separate appeals. Further, the Attorney General also filed a cross-claim in the KIUC appeal (Civil Action No. 15-CI-00168) raising the issues raised in its original appeal;

WHEREAS, there currently is pending before the Commission Case No. 2014-00450. Commission Case No. 2014-00450 is a two-year review of the operation of the Company's fuel adjustment clause, and includes the six-month period at issue in Commission Case No. 2014-00225;

WHEREAS, the Signatory Parties have reviewed the issues raised in P.S.C. Case No. 2014-00396, and the Signatory Parties have reached a settlement of the case, including the issues raised therein;

WHEREAS, Kentucky Power and KIUC are desirous of resolving the issues raised in their appeals of the Commission's January 22, 2015 Order in Case No. 2014-00225, as well as the matters before the Commission in Case No. 2014-00450, in connection with the resolution of this case;

WHEREAS, although not a signatory to this agreement, the Attorney General has indicated he is willing to resolve his appeal of the January 22, 2015 Order of the Commission in Case No. 2014-00225 in accordance with the agreement reached herein by KIUC and Kentucky Power to resolve their appeals of that Order;

WHEREAS, 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; and

WHEREAS, the Signatory Parties believe that this Settlement Agreement provides for fair, just and reasonable rates,

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

1. General Rate Change.

Effective for service rendered on or after June 30, 2015 (the first day of the July 2015 billing cycle) Kentucky Power shall implement a rate adjustment sufficient to generate additional annual retail revenues of $45.4 million based on the September 30, 2014 test year used by Kentucky Power in the Rate Application. The $45.4 million rate adjustment represents the net effect of the decrease in base rates described below and the establishment or modification of Tariff B.S.1.O.R., Tariff B.S.R.R., Tariff E.S., and the Economic Development Surcharge ("K.E.D.S.")

(a) The new base retail rates to be effective June 30, 2015 result in a decrease of $23.0 million in the amount to be recovered through base rates as illustrated on **EXHIBIT 1** to this Settlement Agreement. The $23.0 million decrease in base retail rates was allocated across all tariff classes.

(b) Kentucky Power agrees to design rates and tariffs, including the addition or modification of Tariff B.S.1.O.R., Tariff B.S.R.R., K.E.D.S., and Tariff E.S, that will generate an additional $45.4 million in retail rates, as illustrated on **EXHIBIT 1** to this Settlement

Agreement, based on the September 30, 2014 test year used by Kentucky Power in the Rate Application.

(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 April 30, 2015.

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

(c) Except as provided in Paragraph 8(f), the new base retail rates reflecting the $23.0 million decrease in base retail rates shall remain in effect until the Commission's Order modifying the Company's base retail rates in Kentucky Power's next base rate case. The rates established in Tariff B.S.1.O.R., Tariff B.S.R.R., and Tariff E.S, as further described below, shall be modified from time to time in accordance with the provisions of those tariffs.

2. <u>Rate of Return On Equity For Certain Purposes</u>.

Kentucky Power shall be authorized a 10.25% return on equity that will be utilized in Tariff E.S., Tariff B.S.R.R., Tariff B.S.1.O.R., for purposes of determining the Weighted Average Cost of Capital ("WACC"), and accounting for the allowance for funds used during construction ("AFUDC").

3. <u>Capitalization and Gross Revenue Conversion Factor</u>.

Kentucky Power shall utilize a WACC of 7.34% and a gross revenue conversion factor ("GRCF") of 1.616424. The calculation of the WACC reflects no short term debt. This WACC and GRCF shall remain constant 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 **EXHIBITS 2 AND 3**, respectively.

4. Kentucky Power's Tariff E.S.

Kentucky Power's 2014 Environmental Compliance Plan is approved. The annual baseline level for environmental cost recovery under the tariff shall be $34,902,677, and the monthly baseline amounts shall be as set forth in **EXHIBIT 4** to this Settlement Agreement. In accordance with paragraph 6 of the July 2, 2013 Stipulation and Settlement Agreement in Case No. 2012-00578, as approved by the Commission's October 7, 2013 Order, all costs associated with Mitchell Units 1 and 2 Flue Gas Desulfurization equipment have been excluded from base rates and the environmental baseline level and shall be recovered exclusively through Tariff E.S. Except as modified herein, Tariff E.S. is approved as filed.

5. Kentucky Power's Tariff S.S.C.

Tariff S.S.C. is approved as filed with the Company's application in this case, effective the first billing cycle of July, 2015 with the following modifications:

(a) Effective for service rendered in the first billing cycle of July 2015 (beginning June 30, 2015), any over or under difference between each month's actual off-system sales margins and the monthly baseline shall be shared between the customers and Kentucky Power on a 75% (customer)/25% (Kentucky Power) basis.

(b) Effective for service rendered in the first billing cycle of July 2015 (beginning June 30, 2015), the sharing of off-system sales margins shall be calculated using an annual baseline of $15,136,000. Tariff S.S.C., as conformed to reflect the modifications described herein is attached as **EXHIBIT 5** and shall be approved. The monthly amounts shall be as set forth in **EXHIBIT 5** of this Settlement Agreement. The monthly off-system sales margin baseline amounts include and monthly actual off-system sales margins shall be calculated utilizing the methodology for allocating no load costs described in Paragraph 11 of this Agreement.

(c) Consistent with the practice prior to the suspension of the sharing of system sales margins effective January 1, 2014, the Tariff S.S.C. credit (charge) applicable to customers' bills in any month shall be calculated using the actual off-system sales margins for the calendar month two months prior to the billing month. For purposes of clarity, the off-system sales margins for the July 2015 and August 2015 billing cycles shall be calculated using the May 2015 and the June 2015 actual off-system sales margins, respectively.

6. <u>Tariff B.S.R.R.</u>

(a) The Company's Big Sandy Retirement Rider ("Tariff B.S.R.R.") as set forth in **Exhibit 6** to this Settlement Agreement shall be approved.

(b) The initial B.S.R.R. revenue requirement shall not include any estimated Big Sandy Retirement Costs. The calculation of the initial B.S.R.R. revenue requirement is set forth in **Exhibit 7** to this Settlement Agreement.

(c) Subject to review by the Commission as set forth below, the B.S.R.R. rate shall be modified annually effective cycle 1 of the October billing cycle of each year.

(d) Actual retirement related costs incurred subsequent to June 30, 2015 shall be deferred and added as they are incurred to the unamortized B.S.R.R. regulatory asset. The calculation of the pre-tax carrying charge on the unamortized balance of the B.S.R.R. regulatory asset will be determined net of related B.S.R.R. Accumulated Deferred Incomes Taxes ("ADIT"). The monthly B.S.R.R. revenues that exceed the current month pre-tax WACC carrying charges on the unamortized balance of the B.S.R.R. regulatory asset (including both the unamortized B.S.R.R. costs initially included in the B.S.R.R. revenue requirement and the post-

June 30, 2015 actual retirement-related costs subsequently deferred) will be used to reduce the unamortized B.S.R.R. costs to be recovered. The pre-tax WACC rate initially used to develop the pre-tax WACC carrying charges shall be as set forth in **EXHIBIT 2**; the pre-tax WACC rate used to develop the pre-tax WACC carrying charges shall be re-established in each of the Company's base rate cases. The calculation of the B.S.R.R. revenue requirement, and corresponding rate as shown on **EXHIBIT 6**, will be performed in a manner to recover all actual B.S.R.R. incurred costs including related pre-tax WACC carrying charges on the unamortized B.S.R.R. balance over the remaining life of the 25-year amortization period (2040).

(e) The Company shall file for review by the Commission no later than August 15 of each year the amount of actual Big Sandy Retirement Costs, including the pre-tax WACC carrying charge, incurred between July 1 of the prior year and June 30 of the current year, and supporting documentation. A copy of the annual filing shall be served on counsel for all parties to this proceeding. The Company's annual filing shall also provide the June 30 current year unamortized balance of the B.S.R.R. regulatory asset and the corresponding rate as shown on **EXHIBIT 6**. The annual B.S.R.R. filings will reflect revised B.S.R.R. rates to recover the unamortized B.S.R.R. costs, including the pre-tax WACC carrying charges, over the remaining life of the 25-year amortization period (2040). The amended B.S.R.R. rate shall become effective cycle 1 of the October billing cycle of each year, subject to any adjustments made by the Commission.

(f) If required at the conclusion of the final year of the 25-year collection period to recover completely any remaining unamortized balance of the B.S.R.R. regulatory asset, to recover all actual retirement costs in the final year of the 25 year collection period, and to true-up any over or under-recovery, a final one-year B.S.R.R. rate shall be established.

7. Tariff B.S.1.O.R.

The Company's Tariff B.S.1.O.R. attached as **EXHIBIT 8** shall be approved.

8. Distribution System Reliability –Vegetation Management.

Effective July 1, 2015, Kentucky Power's existing Distribution Vegetation Management Plan (approved by the Commission's June 29, 2010 Order in Case No. 2009-00459) shall be modified as described below, and the Company shall make the following expenditures for Distribution Vegetation Management with respect to distribution system reliability:

(a) Kentucky Power agrees to implement Scenario 2 as described at pages 25-26 of the direct testimony of Company Witness Everett G. Phillips in this case, as further modified as described in the Company's response to KPSC 3-7 and to align the expenditures to match the increased revenues to be provided beginning approximately July 1, 2015 as a result of the Commission's Order approving this Settlement Agreement. The effect of the alignment of the increased revenues with increased expenditures is to shift the expenditures six months into the future from that illustrated in the Company's response to KPSC 3-7. The Company projects it will be on a five-year maintenance cycle beginning July 1, 2019. Beginning July 2015 Kentucky Power shall make operation and maintenance expenditures for distribution system vegetation management in the sums shown on **EXHIBIT 9** to this Settlement Agreement. The mileage targets for the three phases (2010 Unanimous Settlement Agreement, Interim Clear, and Maintenance (5-years growth)) are shown on **EXHIBIT 10**.

(b) In calculating the allocations set forth in **EXHIBIT 1** to this Settlement Agreement, $10,655,900 of the increase in revenue requirements that is associated with the increased reliability spending described in this paragraph 8 of this Settlement Agreement was allocated solely to tariff classes with primary and secondary service offerings.

(c) On or before September 30, 2015, and each September 30 thereafter, Kentucky Power shall file with the Commission a reliability work plan outlining the planned Distribution Vegetation Management expenditures for the following calendar year. The work plan shall identify on a circuit-by-circuit basis the Distribution Vegetation Management work to be performed during the relevant calendar year and the projected operation and maintenance expenditures during the relevant period to carry out the planned work.

(d) On April 1, 2016, and each April 1 thereafter, Kentucky Power shall file with the Commission the following reports concerning system reliability and the expenditure of the funds described in subparagraphs (a) and (b) of this paragraph:

(i) the Kentucky Power Customer Average Interruption Duration Index for the reporting period;

(ii) the Kentucky Power System Average Interruption Frequency Index for the reporting period;

(iii) the Kentucky Power System Average Interruption Duration Index for the reporting period;

(iv) a description on a circuit-by-circuit basis of the Distribution Vegetation Management work performed by Kentucky Power during the reporting period;

(v) a description on a circuit-by-circuit basis of the operation and maintenance expenditures for Distribution Vegetation Management performed by Kentucky Power during the reporting period; and

(vi) any unanticipated problems or further information useful to the Commission's review of the report. In the event Kentucky Power is unable to complete a material portion of the planned work on a circuit during a reporting period, Kentucky Power shall provide an explanation for its inability to do so.

(e) Kentucky Power shall use reasonable and prudent efforts to adhere to and carry out any work plan filed in connection with this subparagraph.

(i) Kentucky Power may alter its proposed spending as detailed in its annual September 30 filing upon discovery of a more pressing need for Distribution Vegetation Management expenditures relating to system reliability purposes. Kentucky Power shall notify the Commission in writing within 30 days of any material deviation from the work plans filed in connection with this subparagraph.

(ii) In the event that the Company's expenditures in any Vegetation Management Year are either greater than or less than the $27,661,060 included in annual base rates, the annual shortfall or excess shall be added to or removed, respectively, from the scheduled future expenditures. To reflect the commencement of additional funding effective June 30, 2015, the Vegetation Management Year shall be July 1 through June 30. If the cumulative Company annual expenditures during any single Vegetation Management Year are less than the $27,661,060 included in annual base rates, the Company shall defer on its books any such shortfall as a regulatory liability. This deferral is a one-way balancing account. Such regulatory liability deferrals shall continue to be recorded on the Company's books until the Commission sets base rates in the Company's next base rate case. If Kentucky Power has underspent during the four Vegetation Management Year periods ending June 30, 2019 the $27,661,060 of annual vegetation management costs on a cumulative basis (4 x $27,661,060 or $110,640,240) at the time the Commission sets base rates in the Company's next base rate case after June 30, 2019, the amount underspent will either be refunded to customers or used to reduce the revenue requirement in that case. Alternatively, if Kentucky Power has overspent the $27,661,060 of annual vegetation management costs on a cumulative basis, the Company will not be entitled to seek recovery of such costs in a future base rate proceeding. The Company's expected vegetation management expenditures are shown on **EXHIBIT 9**.

(f) Beginning cycle 1 of the July 2019 billing cycle, which is the approximate date the Company anticipates commencing the five-year maintenance cycle, and until the Company's base rates are established in the first base rate case after June 30, 2019, the Company shall reduce the base retail rates for those tariff classes with primary and secondary service offerings by $11,780,408. The reductions shall be allocated solely to tariff classes with primary and secondary service offerings, and in the same fashion as the $10,655,900 increase in revenue requirements to fund the Distribution Vegetation Management Program described in this paragraph 8 was allocated, as shown on **EXHIBIT 9**. Kentucky Power agrees to the make the tariff filings required to implement the rate reduction described in this subparagraph (f), and further shall include in its tariff the provision shown on page 2 of **EXHIBIT 9** recognizing the reduction.

(g) A copy of any report or notice filed with the Commission under this paragraph 8 shall concurrently be served upon counsel for all parties to this proceeding.

9. Depreciation And Amortization of Deferred Costs.

(a) Kentucky Power shall continue to include in the calculation of its annual distribution depreciation expense the depreciation rates currently approved by the Commission in, and utilized by Kentucky Power since, its 1991 rate case (P.S.C. Case No. 91-066.) The Company shall include in the calculation of its annual depreciation expense the Company's proposed depreciation rates for transmission and general plant. The Company shall include in the calculation of its annual generation depreciation expense the Company's proposed depreciation rates for generation, except as modified with respect to Mitchell Production Plant Account No. 311 (Structures & Improvements), 312 (Boiler Plant Equipment), 312 (Boiler Plant Equipment (SCR Catalyst), 314 (Turbogenerator Units), 315 (Accessory Electrical Equipment), and 316 (Miscellaneous Power Plant Equipment) in Exhibit LK-16 of the testimony of KIUC Witness Lane Kollen. A complete schedule of the depreciation rates to be approved by the Commission for use by Kentucky Power in calculating its annual depreciation expense is set forth in **EXHIBIT 11.**

(b) Kentucky Power shall recover and amortize the $12,146,000 in deferred costs associated with the 2012 storms, as approved by the Commission in its January 7, 2013 Order in Case No. 2012-00445. The deferred costs shall be amortized over a five year period at an annual amount of $2,429,200.

(c) Kentucky Power shall amortize the $4,657,731 jurisdictional balance of Accumulated Deferred State Income Tax ("ADSIT") related to the acquisition of the Mitchell Plant. The Company shall amortize the ADSIT balance over a three year period at an annual amount of $1,552,577.

10. <u>Economic Development Surcharge</u>.

(a) The Company shall collect from all customers an economic development surcharge of $0.15 per meter per month. All economic development surcharge funds collected by Kentucky Power shall be matched dollar-for-dollar by Kentucky Power from shareholder funds. The proceeds of the economic development surcharge and the 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 economic development surcharge, and the matching shareholder contribution, shall remain in effect until changed by order of the Commission.

(b) The Company shall modify its tariffs to provide for the collection of the $0.15 per meter per month economic development surcharge.

(c) Kentucky Power shall file on or before March 31, 2016, and each March 31st thereafter, 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. <u>No Load Cost Allocation</u>.

Upon the Order of Commission in Case No. 2014-00396 approving this Settlement Agreement without modification becoming final and non-appealable, and there having been no modification to this Settlement Agreement as a result of any rehearing or appeal:

(a) The Company shall withdraw and dismiss with prejudice its pending appeal before the Franklin Circuit Court in Civil Action No. 15-CI-00168 of the Commission's January 22, 2015 order in Case No. 2014-00225;

(b) KIUC shall withdraw and dismiss with prejudice its pending appeal before the Franklin Circuit Court in Civil Action Nos. 15-CI-168 (counterclaim) and 15-CI-190 of the Commission's January 22, 2015 order in Case No. 2014-00225. By separate agreement embodying the terms of this paragraph 11, the Attorney General, who is not a signatory to this

Settlement Agreement, KIUC, and Kentucky Power have agreed the Attorney General shall withdraw and dismiss with prejudice his appeal in Civil Action Nos. 2015-CI-168 (counterclaim) 2015-CI-180 (original appeal by Attorney General), and 2015-CI-00190 (cross-claim by Attorney General) in consideration of the Company withdrawing and dismissing its appeal in Civil Action No. 2015-CI-168 in accordance with this paragraph 11;

(c) The Company shall not recover any Mitchell no load costs incurred during the period from January 1, 2014 through May 31, 2015 (the "Overlap Period"). Those Mitchell no load costs already recovered by the Company during the Overlap Period shall be refunded without interest consistent with the terms of the Commission's January 22, 2015 Order in Case No. 2014-00225. The Signatory Parties agree the refund of Mitchell no loads costs required by the Commission's January 22, 2015 Order in Case No. 2012-00225 resolves all issues relating to the recovery through the fuel adjustment clause of the Company's no load costs in Case No. 2014-00450, and any subsequent fuel adjustment clause review proceedings reviewing the Company's recovery of fuel costs during the Overlap Period.

(d) KIUC shall withdraw the joint testimony of Lane Kollen filed in Case No. 2014-00450 on behalf of the Attorney General and KIUC.

(e) Following the end of the Overlap Period, the Company shall allocate fuel costs to off system sales utilizing supply curves for each of the Company's units and any purchases. The Company will then assign the highest dollar per Megawatt-hour incremental variable costs of all of these resources to off system sales down to the applicable minimum of the units on an hourly basis. This method will continue until fuel and/or purchase costs have been allocated to all off system sales. All other fuel and purchase power costs, including no load fuel costs, will remain with internal load. In the event that the sum of the unit minimums exceeds

Kentucky Power's internal load, the sum of all of the units remaining costs, excluding the no load costs, is computed on a $/MWh basis, and this cost is assigned to the MWhs of any remaining off-system sales.

(f) The Company shall inform the Commission of proposed prospective changes in the allocation of fuel costs to Kentucky retail customers prior to implementing the change. Any such change shall remain subject to Commission review and approval pursuant to 807 KAR 5:056.

12. Biomass Energy Rider.

(a) The Company's Biomass Energy Rider ("Tariff B.E.R.") shall be revised as set forth in **Exhibit 12**. Under the revised Tariff B.E.R., total charges to be recovered shall include an energy charge and a demand charge. The energy charge shall be determined by the metered energy output of the generating facility at the annual average PJM AEP Zone Locational Marginal Price ("LMP"). The demand charge shall be calculated by subtracting the energy charge from the total annual charges. For residential customers, the total charges under Tariff B.E.R. (energy and demand) shall continue to be based on residential energy use recorded at customer meters. For non-residential customers, the residual energy value (total energy charge less the energy charge for residential customers) will be allocated based on energy. The residual demand costs (total demand costs less the demand cost for residential customers) will be allocated among the non-residential customers based on a percentage of non-fuel revenues.

(b) This Settlement Agreement and the revision to Tariff B.E.R. shall in no way affect: (i) the validity of the Commission's October 10, 2013 Order in Case No. 2013-0144 approving the ecoPower Renewable Energy Purchase Agreement; (ii) Kentucky Power's right under KRS 278.271 to full cost recovery with respect to the ecoPower Renewable Energy

Purchase Agreement; or (iii) the current appeal by KIUC of the Commission's October 10, 2013 Order.

13. PJM Cost Deferral.

(a) In the event the Company's calendar year return on equity falls below 10.00%, calculated as a thirteen month average on a per books basis, the Company will be authorized to defer for future recovery through creation of a regulatory asset that portion, if any, of PJM costs incurred during that calendar year in excess of the amount of PJM costs included in base rates ($74,856,675) so as to increase the Company's return on equity for the calendar year to no more than 10.00%.

(b) The PJM costs to be deferred for future recovery through this mechanism are those categories of charges and credits identified on page 15 of the direct testimony of Company Witness Vaughan, and any new PJM LSE charges or credits that may arise and be billed to the Company per the PJM tariffs. A copy of page 15 of the direct testimony of Company Witness Vaughan is attached as **EXHIBIT 13**. Subject to Commission review and approval, the Company shall be authorized to recover and amortize the Incremental PJM Costs over five years and begin recovery of the Incremental PJM Costs beginning when the Commission sets base rates in the Company's next base rate case.

(c) The Company agrees that it shall not book a carrying charge or earn a return on any amounts deferred pursuant to this Paragraph 13, including during any deferral or amortization periods.

(d) Kentucky Power agrees beginning on or before March 31, 2016, and each March 31st thereafter, it shall make an informational filing with the Commission quantifying and describing the amounts deferred in accordance with this paragraph 13. A copy of this annual informational filing shall be served by Kentucky Power upon counsel for all parties to this proceeding.

14. NERC Compliance and Cybersecurity Deferral.

(a) The Company shall track and defer for future review by the Commission and recovery by the Company any post-June 30, 2015 incremental costs incurred by the Company in complying with new NERC compliance or cybersecurity requirements.

(b) The NERC compliance and cybersecurity costs to be deferred for future recovery through this mechanism are those categories of costs identified on pages 28 and 29 of the direct testimony of Company Witness Wohnhas. A copy of pages 28 and 29 of the direct testimony of Company Witness Wohnhas is attached as **EXHIBIT 14.** The Company shall recover and amortize these costs, subject to Commission review and approval, over five years and begin recovery of the costs when the Commission sets base rates in the Company's next base rate case.

(c) Kentucky Power agrees beginning on or before March 31, 2016, and each March 31st thereafter, it shall make an informational filing with the Commission quantifying and describing the amounts deferred in accordance with this paragraph 14. A copy of this annual informational filing shall be served by Kentucky Power upon counsel for all parties to this proceeding.

15. School Energy Manager Program.

(a) Kentucky Power shall file an application to amend Tariff D.S.M. to expand its current School Energy Manager Program by an amount not to exceed $200,000 per year for two years to (1) fund up to an additional six school energy managers as part of the expansion of the School Energy Manager Program to the Company's entire service territory; and

(2) to the extent funds are available, to fund school energy efficiency projects. In order for the school districts to properly budget for the upcoming school years, the Company will request an order on the Company's application by June 30, 2015.

(b) Beginning on or before March 31, 2016, and each March 31st thereafter, Kentucky Power agrees to make an informational filing with the Commission describing the manner in which the additional funds described in subparagraph (a) were expended. KSBA agrees to cooperate with the Company by providing the information required to make the annual report. A copy of this annual informational filing shall be served by Kentucky Power upon counsel for all parties to this proceeding.

16. Tariff K-12 School.

(a) The Company shall establish a new pilot Tariff K-12 School as set forth in **Exhibit 15**. Tariff K-12 School shall be available for general service to K-12 schools subject to KRS 160.325 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, Tariff M.G.S., 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.

(b) Service under Tariff K-12 School shall be optional. Tariff K-12 shall remain in effect until a final order is issued in the Company's next general base rate case, at which time this Tariff will be reviewed using the then available load research data to evaluate its continuance thereafter.

(c) Tariff K-12 School attached as **EXHIBIT 15** is approved.

17. Tariff C.S. – I.R.P.

The Company agrees that it will amend Tariff C.S.-I.R.P., if necessary, to be consistent with the revised PJM criteria in the event PJM revises its criteria governing what interruptible load qualifies as capacity for the purpose of the Company's FRR obligation.

18. New Tariff I.G.S.

The Company's new Industrial General Service Tariff ("Tariff I.G.S.") as set forth in **EXHIBIT 16** to this Settlement Agreement shall be approved.

19. 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 $16.00 per month proposed by the Company in its filing in this case.

(b) Tariff Q.P.; Tariff C.I.P.-T.O.D.; Rider E.C.S., Emergency Curtailable Service – Capacity and Energy; Rider E.P.C.S., Energy Curtailable Service Rider; and Tariff R.T.P. shall be removed from the Company's filed tariffs.

(c) Tariff C.C. shall be amended to reflect an updated charge and to incorporate an annual true up mechanism as described in the direct testimony of Company Witness Rogness.

(d) Tariff C.S.-I.R.P. shall be amended to incorporate a new credit rate and to expand the total contract capacity authorized under this tariff as described in the direct testimony of Company Witness Rogness.

(e) Tariff A.T.R. shall be amended to allow a temporary extension of the asset transfer rider to allow the Company to recover the full amount of the authorized revenue requirement as described in the direct testimony of Company Witness Rogness.

(f) Tariff P.P.A. shall be amended to amend the monthly rate formula to include a variable to allow the Company to recover the cost of power purchased unrelated to forced generation or transmission outages that are calculated in accordance with the Company's peaking unit equivalent methodology as described in the direct testimony of Company Witness Rogness. Kentucky Power agrees the costs recovered through Tariff P.P.A. shall be subject to periodic review and approval by the Commission.

(g) The Terms and Conditions shall be amended to reflect changes to the Company's schedule of special or non-recurring charges as described in the direct testimony of Company Witness Rogness.

20. Non-Rate Tariff Changes.

Kentucky Power and the Intervenors agree that the non-rate terms of the following tariffs may be modified or implemented as described in the direct testimony of Company Witness Rogness:

Tariff Modified or Implemented

Terms and Conditions of Service
R.S.
R.S.-L.M.-T.O.D.
R.S.-T.O.D.
R.S.-T.O.D.2

Tariff Modified or Implemented

S.G.S.
S.G.S.-T.O.D.
M.G.S.
C.A.T.V.
O.L.
COGEN/SPP I
COGEN/SPP II
T.S.
N.U.G.
N.M.S.
MGS TOD
MW
SL
AFS
GPO
LGS
LGS TOD
DSM

Kentucky Power and the Intervenors also agree that the incidental, non-rate text changes identified on Exhibit JAR-9 shall be implemented.

21. 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 after the first billing cycle of July, 2015 (June 30, 2015).

22. 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, and 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.

23. Failure Of Commission To Approve Settlement Agreement.

If the Commission does not accept and approve this Settlement Agreement in its entirety and without modification, and absent agreement to the modification by the party affected thereby, this Settlement Agreement shall be void and withdrawn by Kentucky Power and the Settling Intervenors from further consideration by the Commission and none of the parties to this Settlement Agreement shall be bound by any of the provisions herein.

24. 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.

25. 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.

26. 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 made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into this Settlement Agreement.

27. 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 operating income of Kentucky Power are unknown and this Settlement Agreement shall be implemented as written.

28. 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.

29. 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.

30. 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.

31. 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.

32. Counterparts.

This Settlement Agreement may be executed in multiple counterparts.

33. 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 challenge any adjustment, in any future rate proceeding of Kentucky Power.

IN WITNESS WHEREOF, this Settlement Agreement has been agreed to as of this 30th day of April 2015.

KENTUCKY POWER COMPANY

By: Mark R. Overstreet

MARK R. OVERSTREET

Its: Attorney

KENTUCKY INDUSTRIAL UTILITY
CUSTOMERS, INC.

By: Michael L. Kurtz
Michael L. Kurtz
Its: Attorney

KENTUCKY SCHOOL BOARDS
ASSOCIATION

By: Matthew M. [illegible]

Its: Attorney on behalf of KSBA

CASE NO. 2014-00396 SETTLEMENT AGREEMENT EXHIBITS

1. Allocation of $23.0 million base rate decrease and $45.4 million increase in annual retail revenues.
2. Calculation of Weighted Average Cost of Capital
3. Calculation of Gross Revenue Conversion Factor
4. Calculation of Monthly Base Amount of Environmental Costs
5. Revised Tariff S.S.C.
6. Revised Tariff B.S.R.R.
7. Calculation of Initial B.S.R.R. Revenue Requirement
8. Tariff B.S.1.O.R.
9. Schedule of Annual Vegetation Management Expenses
10. Vegetation Management Mileage Targets
11. Schedule of Depreciation Rates
12. Revised Tariff B.E.R.
13. Page 15 of the direct testimony of Company Witness Vaughan
14. Pages 28-29 of the direct testimony of Company Witness Wohnhas
15. Tariff K-12 School
16. Tariff I.G.S.

Exhibit 1

Tariff	Number of Customers	Current Revenue	Settlement Base Revenue	Settlement Rider Revenue	Settlement Total Revenue	Net Settlement Increase	Settlement ROR %	% Increase
Residential	138,300	$230,140,567	$224,394,156	$28,515,690	$252,909,845	$22,769,279	4.25%	9.89%
SGS	23,823	$19,611,846	$18,711,833	$2,634,305	$21,346,138	$1,734,293	13.31%	8.84%
MGS	7,297	$59,677,592	$57,105,498	$7,857,059	$64,962,557	$5,284,965	14.15%	8.86%
Schools	183	$13,648,403	$12,598,231	$1,749,853	$14,348,085	$699,681	10.64% *	5.13%
LGS	673	$56,921,244	$54,650,948	$7,309,445	$61,960,394	$5,039,150		8.85%
IGS	88	$171,550,109	$161,500,720	$19,197,129	$180,697,850	$9,147,741	7.70%	5.33%
OL	**	$7,256,320	$6,905,967	$920,785	$7,826,752	$570,432	10.44%	7.86%
SL	56	$1,422,709	$1,357,690	$178,894	$1,536,584	$113,876	15.57%	8.00%
MW	11	$364,284	$348,257	$45,354	$393,612	$29,328	12.99%	8.05%
Total	170,431	$560,593,073	$537,573,301	$68,408,515	$605,981,816	$45,388,743	6.96%	8.10%

* Schools part of LGS class in cost-of-service study, separate rate of return is not available
** Customers included in count for tariff of main (non-lighting) account

KENTUCKY POWER COMPANY
COST OF CAPITAL
TEST YEAR ENDED 9/30/2014

Line No. (1)	Description (2)	Reapportioned Kentucky Jurisdictional Capital (3)	Percentage of Total (4)	Annual Cost Percentage Rate (5)	Weighted Average Cost Percent (6) = (4) X (5)	Gross-Up Factor (7)	Pre-Tax Weighted Average Cost Percent (8) = (6) X (7)
1	Long Term Debt	$585,086,099	51.51%	5.41%	2.79%	1.004977	2.8039%
2	Short Term Debt	0	0.00%	0.26%	0.00%	1.004977	0.0000%
3	Accounts Receivable Financing	51,835,808	4.56%	1.07%	0.05%	1.004977	0.0502%
4	Common Equity	498,888,221	43.93%	10.25%	4.50%	1.616424	7.2739%
5	Total	$1,135,810,128	100.00%		7.34%		10.1280%

EXHIBIT 3

Kentucky Power Company
Computation of the Gross Revenue
Conversion Factor
Test Year Twelve Ended 9/30/2014

Line No. (1)	Description (2)		Percent of Incremental Gross Revenues (3)
1	Operating Revenues		100.00%
2	Less: Uncollectible Accounts Expense		0.30%
3	KPSC Maintenance Fee		0.20%
4	Income Before Income Taxes		99.50%
5	Less: State Income Taxes (L4 X 5.7348%)	5.7348%	5.71%
6	Income Before Federal Income Taxes		93.80%
6b	Section 199 Deduction		2.56%
6c	Taxable Income for Federal Income Taxes		91.24%
7	Less: Federal Income Taxes (L6c X 35.00%)	35.00%	31.93%
8	Operating Income Percentage (L6 - L7)		61.86%
9	Gross Revenue Conversion Factor (100% / L8)		**1.616424**

Exhibit 4

Kentucky Power Company
Calculation of Monthly Base Amount of Environmental Costs
October 1, 2013 to September 30, 2014

Ln No (1)	Month / Year (2)	Monthly Environmental Costs (3)	Adjustment for Pool Termination (4)	Adjustment to Remove Big Sandy (5) #	Leaves only Test Year Rockport Expenses and Gains on Allowances (6) # (3) + (4) + (5)	Include Mitchell Non-FGD (7) #	Rockport Additional Test Year Expenses for O & M, Depreciation, and Return (8) #	Adjusted Environmental Base (9)
1	October 2013	$2,588,033	-$884,674	-$1,672,931	$30,428	$2,814,767	$137,763	$2,982,958
2	November 2013	$2,574,766	-$873,779	-$1,686,320	$14,667	$2,814,767	$65,935	$2,895,369
3	December 2013	$3,956,730	-$921,717	-$3,000,383	$34,630	$2,814,767	$27,591	$2,876,988
4	January 2014	$2,819,234	$0	-$2,789,805	$29,429	$2,586,944	$29,919	$2,646,292
5	February 2014	$2,727,758	$0	-$2,688,504	$39,254	$2,553,628	$31,777	$2,624,660
6	March 2014	$2,361,529	$0	-$2,321,728	$39,801	$2,625,235	$71,957	$2,736,994
7	April 2014	$2,844,327	$0	-$2,804,712	$39,615	$2,672,378	$83,860	$2,795,854
8	May 2014	$2,450,433	$0	-$2,409,658	$40,775	$2,655,200	$86,233	$2,782,209
9	June 2014	$2,788,301	$0	-$2,749,455	$38,846	$2,619,496	$64,756	$2,723,098
10	July 2014	$2,675,318	$0	-$2,638,192	$37,126	$3,343,224	$36,490	$3,416,840
11	August 2014	$2,796,292	$0	-$2,758,034	$38,258	$3,113,126	$33,058	$3,184,443
12	September 2014	$2,146,708	$0	-$2,108,067	$38,641	$3,163,668	$34,665	$3,236,974
	Total	$32,729,430	-$2,680,170	-$29,627,789	$421,471	$33,777,201	$704,005	$34,902,677

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 19-1
CANCELING P.S.C. KY. NO. 10 ________ SHEET NO. 19-1

TARIFF S. S. C.
(System Sales Clause)

APPLICABLE.

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

RATE.

~~In accordance with the Stipulation and Settlement Agreement approved as modified by the Commission by its Order dated October 7, 2013 in Case No. 2012-00578, the System Sales Adjustment Factor will be fixed and maintained at 0.0000 mills/kWh until new base rates are first established by Commission after the effective date of this tariff without regard to the calculation of the Monthly System Sales Adjustment Factor under paragraphs 1 through 6 below.~~ D I D

1. When the monthly net revenues from system sales are above or below the monthly base net revenues from system sales, as provided in paragraph 2 below, an additional credit or charge equal to the product of the KWHs and a system sales adjustment factor (A) shall be made, where "A", calculated to the nearest 0.0001 mill per kilowatt-hour, is defined as set forth below.

   System Sales Adjustment Factor (A) = (.6 *.75* [Tm - Tb])/Sm T

   In the above formulas "T" is Kentucky Power Company's (KPCo) monthly net revenues from system sales in the current (m) and base (b) periods, and "S" is the KWH sales in the current (m) period, all defined below.

2. *The net revenue from KPCo's sales to non-associated companies as reported in the FERC Energy Regulatory Commission's Uniform System of Accounts under Account 447, Sales for Resale, shall consist of and be derived as follows:* N

   a. *KPCo's total revenues from system sales as recorded in Account 447, less b. and c. below.*

   b. *KPCo's total out-of-pocket costs incurred in supplying the power and energy for the sales in a. above.*

   The out-of-pocket costs include all operating, maintenance, tax, transmission losses and other expenses that would not have been incurred if the power and energy had not been supplied for such sales, including demand and energy charges for power and energy supplied by Third Parties.

   c. *KPCo's environmental costs allocated to non-associated utilities in the Company's Environmental Surcharge Report.* N

(Cont'd on Sheet No. 19-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 19-2
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 19-2

TARIFF S. S. C. (Cont'd.)
(System Sales Clause)

3. The base monthly net revenues from system sales are as follows:

Billing Month	System Sales (Total Company Basis)		
January	$ ~~528,886~~	1,651,585	I
February	~~335,167~~	1,413,908	I
March	~~1,530,489~~	1,372,664	R
April	~~1,371,521~~	1,219,883	R
May	~~1,307,472~~	1,238,911	R
June	~~767,124~~	1,171,190	I
July	~~616,234~~	1,399,696	I
August	~~2,136,652~~	1,019,614	R
September	~~1,850,577~~	1,099,550	R
October	~~1,739,665~~	1,151,741	R
November	~~1,538,455~~	1,188,760	R
December	~~1,568,121~~	1,136,496	R
	~~$15,290,363~~	$15,136,000	R

4. Sales (S) shall be equated to the sum of (a) generation (including energy produced by generating plant during the construction period), (b) purchase, and (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) inter-system sales and less (f) total system losses.

5. The system sales adjustment factor shall be based upon estimated monthly revenues and costs for system sales, subject to subsequent adjustment upon final determination of actual revenues and costs.

6. The monthly System Sales Clause shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

7. Copies of all documents required to be filed with the Commission under this regulation 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.

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 38-1**
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 38-1

BIG SANDY RETIREMENT RIDER
(B.S.R.R.)

APPLICABLE.

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

RATE.

1. *Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2012-00578 and the Stipulation and Settlement Agreement dated July 2, 2013 as filed and approved by the Commission, Kentucky Power Company is to recover from retail ratepayers the coal-related retirement costs of Big Sandy Unit 1, the retirement costs of Big Sandy Unit 2 and other site-related retirement costs that will not continue in use on a levelized basis, including a weighted average cost of capital (WACC) carrying cost over a 25 year period beginning when new base rates are set for the Company that include Mitchell Units 1 and 2. The term "Retirement Costs" as used in this agreement are defined as and shall include the net book value, materials and supplies that cannot be used economically at other plants owned by Kentucky Power, and removal costs and salvage credits, net of related ADIT. Related ADIT shall include the tax benefits from tax abandonment losses.*

2. *The allocation of the actual revenue requirement (ARR) between residential and all other customers shall be based upon their respective contribution to total retail revenues for the most recent twelve month period, ending June 30 according to the following formula:*

$$\text{Residential Allocation } RA(y) = ARR(y) \times \frac{\text{KY Residential Retail Revenue } RR(b)}{\text{KY Retail Revenue } R(b)}$$

$$\text{All Other Allocation } OA(y) = ARR(y) \times \frac{\text{KY All Other Classes Retail Revenue } OR(b)}{\text{KY Retail Revenue } R(b)}$$

Where:
(y) = the expense year;

(b) = Most recent available twelve month period ended June 30.

3. *The Residential B.S.R.R. Adjustment shall provide for annual adjustments based on a percent of total revenues, according to the following formula:*

$$\text{Residential B.S.R.R. Adjustment Factor} = \frac{\text{Net Annual Residential Allocation } NRA(y)}{\text{Residential Retail Revenue } RR(b)}$$

Where:
Net Annual Residential Allocation NRA(b) = Annual Residential Allocation RA(y), net of Over/ (Under) Recovery Adjustment;

Residential Retail Revenue RR(b) = Annual Retail Revenue for all KY residential classes for the year (b).

(Cont'd on Sheet No. 38-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 38-2
CANCELLING P.S.C. KY. NO. 10 ________ SHEET NO. 38-2

BIG SANDY RETIREMENT RIDER (CONT'D)
(B.S.R.R.)

RATE. (Cont'd)

4. *The All Other Classes B.S.R.R. Adjustment shall provide for annual adjustments based on a percent of non-fuel revenues, according to the following formula:*

All Other Classes B.S.R.R. Adjustment Factor = *Net Annual All Other Allocation NOA (y)* / *All Other Classes Non-Fuel Retail Revenue ONR(b)*

Where:

Net Annual All Other Allocation NOA(y) = *Annual All Other Allocation OA(y), net of Over/ (Under) Recovery Adjustment;*

All Other Classes Non-Fuel Retail Revenue ONR(b) = *Annual Non-Fuel Retail Revenue for all classes other than residential for the year (b).*

5. *The annual Big Sandy Retirement Rider adjustments shall be filed with the Commission no later than August 15th of each year before it is scheduled to go into effect on Cycle 1 of the October billing cycle, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.*

6. *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 KRS61.870 to 61.884.*

DATE OF ISSUE: December 23, 2014

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ISSUED BY: JOHN A. ROGNESS III

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By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

Exhibit 7

Monthly WACC Calculation

WACC	10.1280%
Monthly	0.8440%
Monthly Payment	1,413,412

Recovery of Estimated June 30, 2015 Reg Asset Balance

Year	Additions	Carrying Charges	Levelized Payment	Calculated Change in RA	Estimated June 30, 2015 Reg Asset Balance	ADIT on RA	ADIT Balance	Balance of Components Subject to WACC
					$207,727,914		($72,704,770)	$135,023,144
1		$13,574,166	$16,960,949	($3,386,783)	$204,341,131	$1,185,374	($71,519,396)	$132,821,735
2		$13,344,355	$16,960,949	($3,616,593)	$200,724,538	$1,265,808	($70,253,588)	$130,470,949
3		$13,098,951	$16,960,949	($3,861,998)	$196,862,540	$1,351,699	($68,901,889)	$127,960,651
4		$12,836,895	$16,960,949	($4,124,054)	$192,738,486	$1,443,419	($67,458,470)	$125,280,016
5		$12,557,056	$16,960,949	($4,403,892)	$188,334,594	$1,541,362	($65,917,108)	$122,417,486
6		$12,258,230	$16,960,949	($4,702,719)	$183,631,875	$1,645,952	($64,271,156)	$119,360,719
7		$11,939,126	$16,960,949	($5,021,822)	$178,610,052	$1,757,638	($62,513,518)	$116,096,534
8		$11,598,370	$16,960,949	($5,362,579)	$173,247,474	$1,876,903	($60,636,616)	$112,610,858
9		$11,234,491	$16,960,949	($5,726,457)	$167,521,016	$2,004,260	($58,632,356)	$108,888,661
10		$10,845,922	$16,960,949	($6,115,027)	$161,405,990	$2,140,259	($56,492,096)	$104,913,893
11		$10,430,986	$16,960,949	($6,529,963)	$154,876,027	$2,285,487	($54,206,609)	$100,669,417
12		$9,987,894	$16,960,949	($6,973,054)	$147,902,973	$2,440,569	($51,766,040)	$96,136,932
13		$9,514,737	$16,960,949	($7,446,212)	$140,456,761	$2,606,174	($49,159,866)	$91,296,895
14		$9,009,473	$16,960,949	($7,951,475)	$132,505,286	$2,783,016	($46,376,850)	$86,128,436
15		$8,469,925	$16,960,949	($8,491,024)	$124,014,263	$2,971,858	($43,404,992)	$80,609,271
16		$7,893,766	$16,960,949	($9,067,183)	$114,947,080	$3,173,514	($40,231,478)	$74,715,602
17		$7,278,511	$16,960,949	($9,682,438)	$105,264,642	$3,388,853	($36,842,625)	$68,422,017
18		$6,621,508	$16,960,949	($10,339,441)	$94,925,201	$3,618,804	($33,223,820)	$61,701,381
19		$5,919,924	$16,960,949	($11,041,025)	$83,884,176	$3,864,359	($29,359,462)	$54,524,714
20		$5,170,734	$16,960,949	($11,790,215)	$72,093,961	$4,126,575	($25,232,886)	$46,861,075
21		$4,370,707	$16,960,949	($12,590,242)	$59,503,719	$4,406,585	($20,826,302)	$38,677,418
22		$3,516,395	$16,960,949	($13,444,554)	$46,059,166	$4,705,594	($16,120,708)	$29,938,458
23		$2,604,113	$16,960,949	($14,356,836)	$31,702,330	$5,024,893	($11,095,815)	$20,606,514
24		$1,629,928	$16,960,949	($15,331,021)	$16,371,309	$5,365,857	($5,729,958)	$10,641,351
25		$589,640	$16,960,949	($16,371,309)	($0)	$5,729,958	($0)	($0)
Total		$216,295,801	$424,023,715	($207,727,914)		$72,704,770		

KENTUCKY POWER COMPANY **P.S.C. KY. NO. 10 ORIGINAL SHEET NO. 39-1**
CANCELLING P.S.C. KY. NO. 10 _________ SHEET NO. 39-1

BIG SANDY UNIT 1 OPERATION RIDER
(B.S.1.O.R.)

APPLICABLE.

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

RATES.

Tariff Class	*\$/kWh*	*\$/kW*
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and Experimental R.S.-T.O.D. 2	*\$0.00330*	—
S.G.S. and S.G.S.-T.O.D.	*\$0.00272*	—
M.G.S.	*\$0.00141*	*\$0.34*
M.G.S. Recreational Lighting, M.G.S.-L.M.-T.O.D., and M.G.S.-T.O.D.	*\$0.00283*	—
L.G.S. and L.G.S.-T.O.D.and K-12 School	*\$0.00139*	*\$0.45*
L.G.S.-L.M.-T.O.D.	*\$0.00276*	—
I.G.S. and C.S.-I.R.P.	*\$0.00139*	*\$0.55*
M.W.	*\$0.00248*	—
O.L.	*\$0.00147*	—
S.L.	*\$0.00147*	—

Tariff BS1OR includes all non-fuel operating expenses related to Big Sandy Unit 1 not otherwise included in Tariff S.S.C. or Tariff FAC. Tariff BS1OR shall also include a return on and of Big Sandy Unit 1 gas conversion capital when placed in service.

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 MGS, LGS and IGS tariff classes.

The Big Sandy Unit 1 Operation Rider factors shall be modified annually to collect the approved annual level of Kentucky retail jurisdictional Big Sandy Unit 1 revenue requirement and any prior review period (over)/under recovery.

The Big Sandy Unit 1 Operation Rider factors shall be determined as follows:
For all tariff classes without demand billing:

$$\text{kWh Factor} = \frac{BS1E \times (BE_{Class}/BE_{Total}) + BS1D \times (CP_{Class}/CP_{Total})}{BE_{Class}}$$

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

For all tariff classes with demand billing:

$$\text{kWh Factor} = \frac{BS1E \times (BE_{Class}/BE_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = \frac{BS1D \times (CP_{Class}/CP_{Total})}{BD_{Class}}$$

(Cont'd on Sheet No. 39-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 23, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

BIG SANDY UNIT 1 OPERATION RIDER (CONT'D)
(B.S.1.O.R)

RATES. (Cont'd)

Where:

1. *"BS1D" is the actual annual retail Big Sandy Unit 1 demand-related costs, plus any prior review period (over)/under recovery.*
2. *"BS1E" is the actual annual retail Big Sandy Unit 1 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}*
(1)	*(2)*	*(3)*	*(4)=(2)x(3)*
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and Experimental R.S.-T.O.D.		*0.0236060%*	
S.G.S and S.G.S.-T.O.D.		*0.0163937%*	
M.G.S.		*0.0177002%*	
M.G.S. Recreational Lighting, M.G.S.-L.M.-T.O.D., and M.G.S.-T.O.D.		*0.0177002%*	
L.G.S.and L.G.S.-T.O.D.and K-12 School		*0.0169381%*	
L.G.S.-L.M.-T.O.D.		*0.0169381%*	
I.G.S. and C.S.-I.R.P		*0.0130626%*	
M.W.		*0.0134057%*	
O.L.		*0.0009431%*	
S.L.		*0.0009890%*	
	BE_{Total}		*CP_{Total}*

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.*

The factors as computed above are calculated to allow the recovery of Uncollectible Accounts Expense of 0.3% and the KPSC Maintenance Fee of 0.1952% and other similar revenue based taxes or assessments occasioned by the Big Sandy Unit 1 Operation Rider revenues.

The annual Big Sandy Unit 1 Operation Rider factors shall be filed with the Commission ten (10) days before it is scheduled to go into effect, 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.

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In Case No. 2014-00396 Dated XXXXXXXX

Exhibit 9
Page 1 of 2

Revision to Table 10 - Phillips Direct Testimony, Page 30

	Scenario Cost Comparison for 4 Year Cycle				Scenario 2 on 5 yr Cycle	Scenario 2 on 5 yr Cycle Revised on 04202015
Year	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 5 Revised
2010	$8,950,346	$8,950,346	$8,950,346	$8,950,346	$8,950,346	$8,950,346
2011	$17,261,128	$17,261,128	$17,261,128	$17,261,128	$17,261,128	$17,261,128
2012	$17,029,248	$17,029,248	$17,029,248	$17,029,248	$17,029,248	$17,029,248
2013	$17,466,579	$17,466,579	$17,466,579	$17,466,579	$17,466,579	$17,466,579
2014	$17,237,965	$17,237,965	$17,237,965	$17,237,965	$17,237,965	$17,237,965
2015	$17,237,965	$27,661,060	$28,467,336	$40,801,455	$27,661,060	$22,327,777
2016	$17,237,965	$27,664,598	$28,182,662	$41,125,000	$27,664,598	$27,664,598
2017	$17,237,965	$27,661,949	$34,371,345	$29,775,649	$27,661,949	$27,661,949
2018	$17,237,965	$27,664,089	$40,459,059	$21,456,386	$27,664,089	$27,664,089
2019	$38,462,690	$20,251,822	$40,054,468	$20,251,822	$16,201,457	$21,534,740
2020	$38,078,063	$20,049,303	$39,653,924	$20,049,303	$16,039,443	$16,039,443
2021	$37,697,283	$19,848,810	$27,696,470	$19,848,810	$15,879,048	$15,879,048
2022	$37,320,310	$19,650,322	$19,650,322	$19,650,322	$15,720,258	$15,720,258
2023	$19,453,819	$19,453,819	$19,453,819	$19,453,819	$15,563,055	$15,563,055
Totals	**$317,909,291**	**$287,851,038**	**$355,934,672**	**$310,357,832**	**$268,000,223**	**$268,000,223**

Annual Level included in Settlement Base Rates	**$27,661,060**
Average Yearly Level beginning July 2019	**$15,880,652**
Base Rate Reduction Beginning July 2019	**$11,780,408**

Class Allocation of Base Rate Reduction *

Class	Voltage: Secondary	Voltage: Primary	Total
Residential	$8,168,487		$8,168,487
SGS	$376,607		$376,607
MGS	$1,213,717	$15,540	$1,229,257
LGS and K-12 Schools	$1,280,582	$184,399	$1,464,981
IGS	$44,413	$451,811	$496,224
OL	$31,131		$31,131
SL	$6,668		$6,668
MW	$7,053		$7,053
Total	$11,128,658	$651,750	$11,780,408

* Allocation of Vegetation Management Costs As-Filed

Addition to Terms and Conditions of Service – Sheet No. 2-11

20. **DISTRIBUTION SYSTEM RELIABILITY – VEGETATION MANAGEMENT ADJUSTMENT**

Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2014-00396 and the Settlement Agreement dated April __, 2015 as filed and approved by the Commission, Kentucky Power shall reduce the base retail rates for those tariff classes with primary and secondary service offerings by an aggregate amount equal to $11,780,408 beginning July 1, 2019 when the Company commences the five-year maintenance cycle. The reduced base rates shall be designed using the tariff class allocation as shown in Exhibit 9 to that Settlement Agreement and the test year billing units as filed by the Company in Case No. 2014-00396 to produce $11,780,408 less revenue annually. The $11,780,408 reduction is the difference between the $27,661,060 built into base rates and the $15,880,652 average on-going annual spending after the interim clearance program period is complete.

Exhibit 10

Table 11: Scenario 5 (Mileage Required for 5 Year Cycle)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Yr 1 Miles	463					371				[illegible]				
Yr 2 Miles		932					771				[illegible]			
Yr 3 Miles			891					788				[illegible]		
Yr 4 Miles				826					812				[illegible]	
Yr 5 Miles					1008					370				[illegible]
Yr 6 Miles						987								
Yr 7 Miles							986							
Yr 8 Miles								986						
Yr 9 Miles									986					
Program Miles	463	932	891	826	1008	1728	1757	1774	1798	1983	1613	1613	1613	1613

Task 1 - # Miles (Unanimous Settlement Agreement)
Task 2 - # Miles Interim Clear at Maintained Cost (4 - 5 to 5 1/2 yrs growth)
Task 3 - # Miles at Maintained Cost (5 yrs growth)

EXHIBIT NO. 11

KENTUCKY POWER COMPANY
DEPRECIATION RATES
FROM THE SETTLEMENT AGREEMENT IN CASE NO. 2014-00396

Acct. No.	Account Title	DEPRECIATION RATES
STEAM PRODUCTION PLANT		
BIG SANDY PLANT (a)		
311	Structures & Improvements	3.78%
312	Boiler Plant Equipment	3.78%
312	Boiler Plant Equip SCR Catalyst	4.78%
314	Turbogenerator Units	3.78%
315	Accessory Electrical Equipment	3.78%
316	Misc. Power Plant Equip.	3.78%
MITCHELL PLANT - (b)		
311	Structures & Improvements	2.66%
312	Boiler Plant Equipment	3.05%
312	Boiler Plant Equip SCR Catalyst	12.50%
314	Turbogenerator Units	1.76%
315	Accessory Electrical Equipment	1.56%
316	Misc. Power Plant Equip.	2.72%
TRANSMISSION PLANT (a)		
350.1	Land Rights	1.44%
352	Structures & Improvements	2.08%
353	Station Equipment	2.15%
354	Towers & Fixtures	2.81%
355	Poles & Fixtures	3.95%
356	OH Conductor & Devices	2.91%
357	Underground Conduit	2.99%
358	Underground Conductor & Devices	2.62%
DISTRIBUTION PLANT (c)		
360.1	Land Rights	3.52%
361	Structures & Improvements	3.52%
362	Station Equipment	3.52%
364	Poles, Towers, & Fixtures	3.52%
365	Overhead Conductor & Devices	3.52%
366	Underground Conduit	3.52%
367	Underground Conductor	3.52%
368	Line Transformers	3.52%
369	Services	3.52%
370	Meters	3.52%
371	Installations on Custs. Prem.	3.52%
373	Street Lighting & Signal Sys.	3.52%
GENERAL PLANT (a)		
389.1	Land Rights	1.59%
390	Structures & Improvements	3.97%
391	Office Furniture & Equipment	3.20%
392	Transportation Equipment	3.62%
393	Stores Equipment	4.15%
394	Tools Shop & Garage Equipment	4.20%
395	Laboratory Equipment	5.76%
396	Power Operated Equipment	5.43%
397	Communication Equipment	5.98%
398	Miscellaneous Equipment	6.73%

Notes:

(a) As per the Settlement Agreement in Case No. 2014-00396, the Company's recommended depreciation rates are to be used for Big Sandy Plant, Transmission and General Plant.

(b) Mitchell Plant depreciation rates are based on the Company's calculation as modified by KIUC witness Kollen.

(c) Distribution Plant depreciation remain unchanged from the Kentucky Power 1991 case (Case No. 91-066).

TARIFF B.E.R.
(Biomass Energy Rider)

APPLICABLE.

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

RATE.

1. When energy is generated and sold to the Company from the ecopower biomass facility, an additional monthly charge shall be assessed. The allocation of the revenue requirement between residential and all other customers shall be based upon their respective contribution to total retail kWh sales during the most recently available 12 month period, according to the following formula:

   Residential Allocation RA(m) = [R*P(m)] * [RS(b) / S(b)]

   All Other Allocation OA(m) = [R*P(m)] * [OS(b) / S(b)]

   Where:
   (m) = the expense month;
   (b) = the most recently available calendar twelve month period.

   In the above formulas "R" is the rate for the current calendar year approved by this commission in the REPA between ecopower and Kentucky Power Company, "P" is the amount of kWh purchased by Kentucky Power in the current (m) period, and "S" is the kWh sales, all defined below.

2. Rate (R) shall be the dollar per MWh as defined in the REPA between ecopower and Kentucky Power Company, including any applicable escalation factor as defined in the REPA.

3. Produced energy (P) shall be the MWh produced and sold to Kentucky Power Company.

4. Sales (S) shall be all KWh sold, excluding intersystem sales. Utility used energy shall not be excluded in the determination of sales (S). Residential Sales (RS) shall be all kWh sold to the residential class. All Other Sales (OS) shall be all kWh sold to all other classes, where (OS) = (S) - (RS).

5. The residential biomass adjustment factor (RBAF) shall be calculated to the nearest 0.0001 mil per kilowatt-hour, as set forth below.

   Residential Biomass Adjustment Factor (RBAF) = RA(m) / RS(m)

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TARIFF B.E.R.
(Biomass Energy Rider)

RATE. (Cont'd)

6. The commercial and industrial biomass adjustment factor applicable to all non-residential tariffs shall consist of two separate rate components: an energy charge per kilowatt-hour (CIBEAF) and a non-energy charge expressed as a percentage of non-fuel revenues (CIBNAF), as set forth below.

$$CIBEAF = OA(m) * \frac{LMP(b)}{R} / OS(m)$$

$$CIBNAF = OA(m) * \frac{R - LMP(b)}{R} / NFR(m)$$

Where:
(m) = the expense month;
(b) = the most recently available calendar twelve month period.

In the above formulas "R" is the rate for the current calendar year approved by this commission in the REPA between ecopower and Kentucky Power Company, "LMP" is the annual average LMP for the most recently available calendar year (b), "NFR" is the non-fuel revenue for all non-residential classes in the current (m) period, and "OS" is the kWh sales, all defined either above or below.

7. Locational Marginal Price (LMP) shall be the average day-ahead location marginal price for the AEP load zone as published by PJM Interconnection, LLC for the most recently available calendar twelve month period;

8. Non-Fuel Revenue (NFR) shall be non-fuel retail revenue for all classes other than residential for the expense month (m).

9. Any over/under recovery will be reflected in the monthly filing for the second billing month following the month the cost is incurred.

10. The monthly biomass energy rider shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustment, which shall include data, and information as may be required by the Commission.

11. 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 KRS61.870 to 61.884.

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RESERVED FOR FUTURE USE

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In Case No. 2014-00396 Dated XXXXXXXX

IV. PJM RIDER

Q. WHAT DOES THE COMPANY PROPOSE TO INCLUDE IN THE PJM RIDER?

A. The Company is proposing to include various PJM Open Access Transmission Tariff (OATT), energy, ancillary and administrative service charges and credits that it incurs from its participation as a load serving entity (LSE) and generation resource owner in the organized wholesale power markets of the PJM RTO.

Q. WHAT SPECIFIC PJM CHARGE AND CREDIT ITEMS IS THE COMPANY PROPOSING TO INCLUDE IN THE PJM RIDER?

A. The Company is proposing to include all of its PJM LSE charges and credits which are currently made up of but not limited to the following items: congestion, Financial Transmission Rights (FTRs), meter corrections, operating reserve, inadvertent energy, economic load response, synchronous condensing, reactive service, black start service, regulation, synchronized reserve, day ahead scheduling reserve, peak hour PJM capacity availability charges, market defaults and administrative services. PJM LSE marginal loss charges and the marginal loss over collection credits will not be included since they are included in the Company's fuel clause.

The Company is also proposing to include the following PJM LSE transmission items: network integration transmission service (NITS) charges, transmission owner scheduling system control and dispatch service (TO) charges, regional transmission expansion plan (RTEP) charges, point-to-point (PTP) transmission service credits, RTO start-up cost recovery charges and expansion cost recovery (ECRC) charges. In addition to the above, the Company also proposes to include any new PJM LSE charges or credits that may arise and be billed to the Company per the PJM tariffs.

to AEP and the excellent work it has been doing for not only its companies, but for the entire utility network across the country.

Q. WHY IS THE NCCR NECESSARY?

A. As detailed in the testimony of Company Witness Stogran, NERC continues to revise existing reliability standards and issue new reliability. standards, and a similar or increased level of activity in the future would be difficult to continue to absorb and recover only through base rates. Cybersecurity needs also continue to grow as new threats emerge and new vulnerabilities are identified. The NCCR provides a mechanism for Kentucky Power to recover compliance costs for cybersecurity in a timely fashion.

Q. WHAT WILL BE RECOVERED THROUGH THE NCCR?

A. The NCCR initially would be established at zero as a placeholder. Going forward, the NCCR is intended to recover capital related costs and O&M compliance costs associated with items such as information technology infrastructure, physical security, workforce training, supervisory control and data acquisition (SCADA) systems, smart grid security systems, internal and external audits, external reporting, and recordkeeping. For example, program costs to perform vulnerability assessments due to a specific identified threat could be a type of cost proposed for inclusion in the NCCR. The Company would ensure that only NERC-related capital and O&M costs are recovered through this mechanism.

AEP is at the forefront of industry efforts to plan and prepare for these types of NERC compliance and cybersecurity obligations. Kentucky Power intends to continue planning and preparing for future compliance and cybersecurity obligations, but unforeseen increases in compliance costs cannot simply be absorbed within existing budgets. If new NERC compliance and cybersecurity costs materialize, Kentucky Power will propose to the Commission, in a rider application, recovery of these identified costs through the NCCR. Company witness Rogness discusses the mechanics of how the NCCR will recover the costs associated with these compliance activities in the event that recovery is pursued.

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

A. Yes.

TARIFF K-12 SCHOOL
(Public 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				
Service Charge per Month	*$ 85.00*	*$ 127.50*	*$ 628.50*	*$ 628.50*
Demand Charge per KW	*$ 4.67*	*$ 4.53*	*$ 4.48*	*$ 4.41*
Excess Reactive Charge per KVA	*$ 3.46*	*$ 3.46*	*$ 3.46*	*$ 3.46*
Energy Charge per KWH	*7.692¢*	*6.535¢*	*4.517¢*	*4.425¢*

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.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 through 22-13 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered.

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

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In Case No. 2014-00396 Dated XXXXXXXX

TARIFF K-12 SCHOOL (Cont'd)
(Public 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. 9-12)

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

BIG SANDY RETIREMENT RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule.

BIG SANDY I OPERATION RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kW and/or kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule.

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of
revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1 through 29-5 of this Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 through 28-2 of this Tariff Schedule.

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE.

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission.

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

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

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TARIFF K-12 SCHOOL (Cont'd)
(Public 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.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the customer purchases power at a single point for both his power and camp requirements.

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.

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TARIFF I.G.S.
(Industrial General Service)

AVAILABILITY OF SERVICE.

Available for commercial and industrial customers with contract demands of at least 1,000 KW. Customers shall contract for a definite amount of electrical capacity in kilowatts, which shall be sufficient to meet normal maximum requirements.

RATE.

	Secondary	Primary	Service Voltage Subtransmission	Transmission
Tariff Code	356	358/370	359/371	360/372
Service Charge per month	$ 276.00	$ 276.00	$ 794.00	$ 1,353.00
Demand Charge per KW				
Of monthly on-peak billing demand	$ 18.23	$ 15.21	$ 10.02	$ 9.75
Of monthly off-peak billing demand	$ 1.10	$ 1.07	$ 1.05	$ 1.04
Energy Charge per KWH	3.357¢	3.241¢	3.205¢	3.167¢

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 .... $0.69/ KVAR

For the purpose of this tariff, the on-peak billing period is defined as 7:00 AM to 9:00 PM for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays and all hours of Saturday and Sunday.

MINIMUM DEMAND CHARGE.

The minimum demand charge shall be equal to the minimum billing demand times the following minimum demand rates:

Secondary	Primary	Subtransmission	Transmission
$19.59/KW	$16.53 /KW	$11.32/KW	$11.03/KW

The minimum billing demand shall be the greater of 60% of the contract capacity set forth on the contract for electric service or 60% of the highest billing demand, on-peak or off-peak, recorded during the previous eleven months.

MINIMUM CHARGE.

This tariff is subject to a minimum charge equal to the Service Charge plus the Minimum Demand Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

(Cont'd on Sheet No. 10-2)

DATE OF ISSUE: December 23, 2014

DATE EFFECTIVE: Service Rendered On And After January 22, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF I.G.S.
(Industrial General Service)

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 through 22-13 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered.

BIG SANDY RETIREMENT RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule.

BIG SANDY 1 OPERATION RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kW and/or kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule.

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1through 29-5 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 through 28-2 of this Tariff Schedule.

(Cont'd on Sheet No. 10-3)

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By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF I.G.S.
(Industrial General Service)

TERM OF CONTRACT.

Contracts under this tariff will be made for an initial period of not less than two years and shall remain in effect thereafter until either party shall give at least 12 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than two years.

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 equal to or greater than 1,000 KW in multiplies of 100 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 available for resale service to mining and industrial Customers who furnish service to Customer-owned camps or villages where living quarters are rented to employees and where the Customer purchases power at a single point for both the power and camp requirements.

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 1,000 KW. The Company shall not be obligated to supply demands in excess of that contracted 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 billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

A Customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by the Customer. When the size of the Customer's load necessitates the delivery of energy to the Customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the Customer's system irrespective of contrary provisions in Terms and Conditions of Service.

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

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By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

TARIFF I.G.S.
(Industrial General Service)

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE.

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission.

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

DELAYED PAYMENT CHARGE.

Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date, an additional charge of 5% of the unpaid portion 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 KVA 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.

The monthly on-peak and off-peak billing demands in KW shall be taken each month as the highest single 15-minute integrated peak in KW as registered by a demand meter during the on-peak and off-peak billing periods, respectively.

The reactive demand in KVARs shall be taken each month as the highest single 15-minute integrated peak in KVARs as registered during the month by a demand meter or indicator.

(Cont'd on Sheet No. 10-4)

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TITLE: Director Regulatory Services

By Authority Of Order By The Public Service Commission

In Case No. 2014-00396 Dated XXXXXXXX

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2014-00396 DATED JUN 2 2 2015

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	$	11.00
Energy Charge per kWh	$	.08910
Storage Water Heating Provision - per kWh	$	.05209
Load Management Water Heating Provision - per kWh	$	.05209
Home Energy Assistance Program Charge per meter per month	$	.15

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

Service Charge per month	$	13.60
Energy Charge per kWh:		
All kWh used during on-peak billing period	$	.13509
All kWh used during off-peak billing period	$	.05209
Separate Metering Provision per Month	$	3.75
Home Energy Assistance Program Charge per meter per month	$	.15

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

Service Charge per month	$	13.60
Energy Charge per kWh:		
All kWh used during on-peak billing period	$	.13509
All kWh used during off-peak billing period	$	.05209
Home Energy Assistance Program Charge per meter per month	$	.15

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

Service Charge per month	$	13.60
Energy Charge per kWh:		
All kWh used during summer on-peak billing period	$	.10833
All kWh used during winter on-peak billing period	$	.12009
All kWh used during off-peak billing period	$	.0801
Home Energy Assistance Program Charge per meter per month	$	.15

S.G.S.
SMALL GENERAL SERVICE

Service Charge per month	$	17.50
Energy Charge per kWh:		
First 500 kWh per month	$	.11826
All over 500 kWh per month	$	.07382

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

Service Charge per month	$	17.50
Energy Charge per kWh:		
All kWh used during on-peak billing period	$	.14475
All kWh used during off-peak billing period	$	.05215

S.G.S.
SMALL GENERAL SERVICE
OPTIONAL UNMETERED SERVICE PROVISION

Service Charge per month	$	13.50
Energy Charge per kWh:		
First 500 kWh per month	$	.11826
All over 500 kWh per month	$	.07382

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

Service Charge per month	$	17.50
Energy Charge per kWh:		
All kWh used during summer on-peak billing period	$	.11510
All kWh used during winter on-peak billing period	$	.12430
All kWh used during off-peak billing period	$	.08782

M.G.S.
MEDIUM GENERAL SERVICE

Secondary Service Voltage:		
Service Charge per month	$	17.50
Energy Charge per kWh:		
kWh equal to 200 times kW of monthly billing demand	$	.10313
kWh in excess of 200 times kW of monthly billing demand	$	.08851
Demand Charge per kW	$	1.91
Primary Service Voltage:		
Service Charge per month	$	50.00
Energy Charge per kWh:		
kWh equal to 200 times kW of monthly billing demand	$	.09472
kWh in excess of 200 times kW of monthly billing demand	$	.08475
Demand Charge per kW	$	1.87
Sub-transmission Service Voltage:		
Service Charge per month	$	364.00
Energy Charge per kWh:		
kWh equal to 200 times kW of monthly billing demand	$	.08749
kWh in excess of 200 times kW of monthly billing demand	$	.08218
Demand Charge per kW	$	1.83

The minimum monthly charge for industrial and coal mining customers contracting for 3-phase service after October 1, 1959, shall be $7.95 per kW of monthly billing demand.

M.G.S.
MEDIUM GENERAL SERVICE
RECREATIONAL LIGHTING SERVICE PROVISION

Service Charge per month	$	17.50
Energy Charge per kWh	$	.09381

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

Service Charge per month	$	3.75
Energy Charge per kWh:		
All kWh used during on-peak billing period	$	.16070
All kWh used during off-peak billing period	$	.05456

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

Service Charge per month	$ 17.50
Energy Charge per kWh:	
All kWh used during on-peak billing period	$ .16070
All kWh used during off-peak billing period	$ .05456

L.G.S.
LARGE GENERAL SERVICE

Secondary Service Voltage:	
Service Charge per month	$ 85.00
Energy Charge per kWh	$ .08081
Demand Charge per kW	$ 4.67
Primary Service Voltage:	
Service Charge per month	$ 127.50
Energy Charge per kWh	$ .06924
Demand Charge per kW	$ 4.53
Sub-transmission Service Voltage:	
Service Charge per month	$ 628.50
Energy Charge per kWh	$ .04906
Demand Charge per kW	$ 4.48
Transmission Service Voltage:	
Service Charge per month	$ 628.50
Energy Charge per kWh	$ .04814
Demand Charge per kW	$ 4.41
All Service Voltages:	
Excess Reactive Charge per KVA	$ 3.46

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	$ .13251
All kWh used during off-peak billing period	$ .05440

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	$	.08657
Off-Peak Energy Charge per kWh	$	.04502
Demand Charge per kW	$	9.55
Primary Service Voltage:		
Service Charge per month	$	127.50
Energy Charge:		
On-Peak Energy Charge per kWh	$	.08356
Off-Peak Energy Charge per kWh	$	.04381
Demand Charge per kW	$	6.85
Sub-transmission Service Voltage:		
Service Charge per month	$	628.50
Energy Charge:		
On-Peak Energy Charge per kWh	$	.08265
Off-Peak Energy Charge per kWh	$	.04344
Demand Charge per kW	$	1.06
Transmission Service Voltage:		
Service Charge per month	$	628.50
Energy Charge:		
On-Peak Energy Charge per kWh	$	.08167
Off-Peak Energy Charge per kWh	$	.04305
Demand Charge per kW	$	1.05
All Service Voltages:		
Excess Reactive Charge per KVA	$	3.46

TARIFF K-12 SCHOOL
PUBLIC SHCOOL

Secondary Service Voltage:		
Service Charge per month	$	85.00
Energy Charge per kWh	$	.07692
Demand Charge per kW	$	4.67
Primary Service Voltage:		
Service Charge per month	$	127.50
Energy Charge per kWh	$	.06535
Demand Charge per kW	$	4.53

Sub-transmission Service Voltage:

Service Charge per month	$ 628.50
Energy Charge per kWh	$ .04517
Demand Charge per kW	$ 4.48

Transmission Service Voltage:

Service Charge per month	$ 628.50
Energy Charge per kWh	$ .04425
Demand Charge per kW	$ 4.41

All Service Voltages:

Excess Reactive Charge per KVA	$ 3.46

TARIFF M.W.
MUNICIPAL WATERWORKS

Service Charge per month	$ 22.90
Energy Charge - All kWh per kWh	$ .08630

Subject to a minimum monthly charge equal to the sum of the service charge plus $8.20 per KVA as determined from customer's total connected load.

TARIFF C.S. – I.R.P.
CONTRACT SERIVCE – INTERRUPTIBLE POWER

Credits under this tariff of $3.68/kW/month will be provided for interruptible load that qualifies under PJM's rules as capacity for the purpose of Kentucky Power's Fixed Resource Requirement obligations.

TARIFF I.G.S.
INDUSTRIAL GENERAL SERVICE

Secondary Service Voltage:

Service Charge per month	$ 276.00
Energy Charge per kWh	$ .03357
Demand Charge per kW	
Of Monthly On-Peak Billing Demand	$ 18.23
Of Monthly Off-Peak Billing Demand	$ 1.10

Primary Service Voltage:

Service Charge per month	$ 276.00
Energy Charge per kWh	$ .03241
Demand Charge per kW	
Of Monthly On-Peak Billing Demand	$ 15.21
Of Monthly Off-Peak Billing Demand	$ 1.07

<u>Sub-transmission Service Voltage</u>:

Service Charge per month	$ 794.00
Energy Charge per kWh	$ .03205
Demand Charge per kW	
Of Monthly On-Peak Billing Demand	$ 10.02
Of Monthly Off-Peak Billing Demand	$ 1.05

<u>Transmission Service Voltage</u>:

Service Charge per month	$1,353.00
Energy Charge per kWh	$ .03167
Demand Charge per kW	
Of Monthly On-Peak Billing Demand	$ 9.75
Of Monthly Off-Peak Billing Demand	$ 1.04

<u>All Service Voltages</u>:
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.

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

Secondary	$ 19.59
Primary	$ 16.53
Subtransmission	$ 11.32
Transmission	$ 11.03

TARIFF O.L.
OUTDOOR LIGHTING

OVERHEAD LIGHTING SERVICE

High Pressure Sodium per Lamp:	
100 Watts (9,500 Lumens)	$ 9.35
150 Watts (16,000 Lumens)	$ 10.65
200 Watts (22,000 Lumens)	$ 12.40
250 Watts (28,000 Lumens)	$ 17.75
400 Watts (50,000 Lumens)	$ 19.20
Mercury Vapor per Lamp:	
175 Watts (7,000 Lumens)	$ 10.55
400 Watts (20,000 Lumens)	$ 18.25

POST-TOP LIGHTING SERVICE

High Pressure Sodium per Lamp:	
100 Watts (9,500 Lumens)	$ 14.15
150 Watts (16,000 Lumens)	$ 23.20
100 Watts Shoe Box (9,500 Lumens)	$ 32.90
250 Watts Shoe Box (28,000 Lumens)	$ 25.95
400 Watts Shoe Box (50,000 Lumens)	$ 43.15
Mercury Vapor per Lamp:	
175 Watts (7,000 Lumens)	$ 12.10

FLOOD LIGHTING SERVICE

High Pressure Sodium per Lamp:	
200 Watts (22,000 Lumens)	$ 14.50
400 Watts (50,000 Lumens)	$ 20.35
Metal Halide:	
250 Watts (20,500 Lumens)	$ 18.00
400 Watts (36,000 Lumens)	$ 22.75
1,000 Watts (110,000 Lumens)	$ 41.50
250 Watts Mongoose (19,000 Lumens)	$ 24.75
400 Watts Mongoose (40,000 Lumens)	$ 29.60

Per Month:	
Wood Pole	$ 3.10
Overhead Wire Span not over 150 Feet	$ 1.80
Underground Wire Lateral not over 50 Feet	$ 6.75

TARIFF S.L.
STREET LIGHTING

Rate per Lamp:	
Overhead Service on Existing Distribution Poles	
High Pressure Sodium	
100 Watts (9,500 Lumens)	$ 7.85
150 Watts (16,000 Lumens)	$ 8.95
200 Watts (22,000 Lumens)	$ 10.80
400 Watts (50,000 Lumens)	$ 16.15

Service on New Wood Distribution Poles	
High Pressure Sodium	
100 Watts (9,500 Lumens)	$ 11.10
150 Watts (16,000 Lumens)	$ 12.30
200 Watts (22,000 Lumens)	$ 14.25
400 Watts (50,000 Lumens)	$ 19.95

Service on New Metal or Concrete Poles	
High Pressure Sodium	
100 Watts (9,500 Lumens)	$ 20.45
150 Watts (16,000 Lumens)	$ 21.45
200 Watts (22,000 Lumens)	$ 27.30
400 Watts (50,000 Lumens)	$ 29.65

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

Monthly Metering Charges:	
Single Phase:	
Standard Measurement	$ 8.15
Time-of-Day Measurement	$ 8.70
Polyphase:	
Standard Measurement	$ 10.65
Time-of-Day Measurement	$ 10.95
Energy Credit per kWh:	
Standard Meter – All kWh	$ .03790
Time-of-Day Meter:	
On-Peak kWh	$ .04640
Off-Peak kWh	$ .03180
Capacity Credit:	
Standard Meter per kW	$ 3.54
Time-of-Day Meter per kW	$ 8.49

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

Metering Charges:	
Single Phase:	
Standard Measurement	$ 8.15
Time-of-Day Measurement	$ 8.70
Polyphase:	
Standard Measurement	$ 10.65
Time-of-Day Measurement	$ 10.95

Energy Credit per kWh:		
Standard Meter – All kWh	$	.03790
Time-of-Day Meter:		
On-Peak kWh	$	.04640
Off-Peak kWh	$	.03180
Capacity Credit:		
Standard Meter per kW	$	3.54
Time-of-Day Meter per kW	$	8.49

TARIFF C.C.
CAPACITY CHARGE

Energy Charge per kWh:		
Service Tariff		
I.G.S.	$	.000656
All Other	$	.001185

RIDER A.F.S.
ALTERNATE FEED SERVICE RIDER

Monthly Rate for Annual Test of Transfer Switch/Control Module	$	14.25
Monthly Capacity Reservation Demand Charge per kW	$	5.76

ECONOMIC DEVELOPMENT SURCHARGE

Applicable to All Rate Classes per meter per month	$	.15

B.S.1.O R.
BIG SANDY UNIT 1 OPERATION RIDER

Residential Service		
Residential Service Load Management Time-of-Day		
Residential Service Time-of-Day		
Experimental Residential Service Time-of-Day 2		
Charge per kWh	$	0.00330
Small General Service		
Small General Service Time-of-Day		
Charge per kWh	$	0.00272
Medium General Service		
Charge per kWh	$	0.00141
Charge per kW	$	0.34

Medium General Service Recreational Lighting Service Provision		
Medium General Service Load Management Time-of-Day Provision		
Medium Service Time-of-Day		
Charge per kWh	$	0.00283
Large General Service		
Large General Service Time-of-Day		
Public Schools		
Charge per kWh	$	0.00139
Charge per kW	$	0.45
Large General Service Load Management Time-of-Day Provision		
Charge per kWh	$	0.00276
Industrial General Service		
Curtailable Service – Interruptible Power		
Charge per kWh	$	0.00139
Charge per kW	$	0.55
Municipal Water Works		
Charge per kWh	$	0.00248
Outdoor Lighting		
Charge per kWh	$	0.00147
Street Lighting		
Charger per kWh	$	0.00147

NONRECURRING CHARGES

Reconnect for non-payment – regular hours	$	21.00
Reconnect for non-payment – overtime hours	$	30.00
Reconnect for non-payment – call out	$	95.00
Reconnect for non-payment – double time	$	124.00
Termination or field trip	$	13.00
Returned Check Charge	$	18.00
Meter Test Charge	$	48.00
Meter Reading Check	$	21.00

APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2014-00396 DATED JUN 22 2015

NON-CONTESTED ADJUSTMENTS TO REVENUES AND EXPENSES

Adjustments	Amount
Capacity Charge Revenues Rockport Unit Power Agreement	($5,719,968)
Weather Normalization (overall)	($2,380,420)
Eliminate Environmental Surcharge Revenues	$2,812,947
Customer Migration Adjustment	$149,766
Customer Annualization Adjustment	($160,351)
Miscellaneous Service Charges	$251,903
Fuel Under (Over) Revenues	($5,298,776)
Asset Transfer Rider Gross-Up	$10,014,069
Remove AEP Pool Costs	($10,480,841)
System Sales Margin	$60,722,845
O&M Expense Interest on Customer Deposit	($2,422)
Normalization / Elimination of Commission Mandated Consultant Cost	$84,864
Normalization Major Storms Adjustment	($647,763)
Amortization Storm Cost Deferral	($2,237,475)
Rate Case Expense	$258,037
Postage Rate Increase Adjustment	$12,219
Eliminate Advertising Expense	($30,610)
Annualization of Lease Costs	$72,974
Reliability Adjustment	$10,655,900
Annualization of Employee Benefit Plan Costs	($206,580)
Annualization Employee Related Expense	$36,587
PJM Charges and Credits Adjustment to Reflect Pool Termination & Mitchell Transfer	$7,584,302
Adjustments to Include Test Year Mitchell Plant O&M and Rate Base	$10,712,560
Eliminate Mitchell O&M FGD	($14,879,350)
Cost of Removal Adjustment 2014	$69,695
Kentucky Power Company Depreciation Annualization Expense	$12,771,261
Amortization of Intangible Expense	$209,475
Mitchell Depreciation Annualization Expense	$3,764,718
Removal of Big Sandy Depreciation	($17,212,456)
ARO Depreciation	$237,400
Remove RTO Amortization	($149,718)
ARO Accretion	$363,539
Annualization of Property Tax Expense	$314,531
KPSC Maintenance Assessment	$92,475
Sales & Use Tax	$116,430
State Franchise Tax	$9,020

APPENDIX D

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2014-00396 DATED JUN 22 2015

Environmental Compliance Plan

Project	Plant	Pollutant	Description	In-Service Year
			Kentucky Power Company's 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 and Rockport	NOx	Costs Associated with NOx Allowances	As Needed
7	Big Sandy, Mitchell and Rockport	SO2	Costs Associated with SO2 Allowances	As Needed
			Kentucky Power Company's Proposed Environmental Compliance Projects	
8	Big Sandy, Mitchell and 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

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DATA REQUEST

KCTA_2_017 Provide the following information regarding the number of poles in KPCO Account 364 as of the twelve months ending December 31, 2015 and December 31, 2016: (a) total number of KPCO poles; (b) total number of 35 foot poles; (c) total number of 40 feet poles; and (d) total number of 45 feet poles.

RESPONSE

Kentucky Power's property records are not maintained by height of pole. Therefore, the requested information by pole height is not available. Kentucky Power's number of total poles in Account 364 as of December 31, 2015 is 215,532 and December 31, 2016 is 216,439.

Witness: Tyler H. Ross

DATA REQUEST

KCTA_2_018 Please provide the information requested in the previous request (KCTA_2_017) for each of the preceding five years 2010 – 2014.

RESPONSE

Kentucky Power's property records are not maintained by height of pole. Therefore, the requested information by pole height is not available. Shown below are Kentucky Power's total number of poles as of December 31, 2010, 2011, 2012, 2013 and 2014:

2010 - 209,984

2011 - 211,134

2012 - 212,645

2013 - 213,900

2014 - 214,650

Witness: Tyler H. Ross

DATA REQUEST

KCTA_2_019 Please provide the following information regarding gross pole investment in KPCO Account 364 as of the twelve months ending December 31, 2015 and December 31, 2016: (a) total gross pole investment in 35 feet poles; (b) total gross pole investment in 40 feet poles; and (c) total gross pole investment in 45 feet poles.

RESPONSE

Kentucky Power's utility pole property records are not maintained by height of pole. Therefore, the requested information by pole height is not available. Please see the Company's response to KCTA_1_004 and KCTA_1_003 for Kentucky Power's gross pole investment in Account 364 as of December 31, 2015 and December 31, 2016, respectively.

Witness: Tyler H. Ross

DATA REQUEST

KCTA_2_020 Please provide the following information regarding depreciation reserve for KPCO Account 364 as of the twelve months ending December 31, 2015 and December 31, 2016: (a) depreciation reserve related to the gross investment in 35 feet poles; (b) deprecation reserve related to the gross investment in 40 feet poles; and (c) depreciation reserve related to the gross investment in 45 feet poles.

RESPONSE

Kentucky Power's property records are not maintained by height of pole. Therefore, the requested information by pole height is not available. Kentucky Power's depreciation reserve in Account 364 as of December 31, 2015 is $77,184,956.94 and December 31, 2016 is $81,514,131.57.

Witness: Tyler H. Ross

DATA REQUEST

KCTA_2_021 Provide continuing property records from KPCO Account 364 as of the twelve months ending December 31, 2015 and December 31, 2016, showing detailed breakdown of pole plant investment according to class of pole (i.e., height, material), vintage, quantity, and cost.

RESPONSE

Please refer to attachments KPCO_R_KCTA_2_21_Attachment1.xls (for 2015) and KPCO_R_KCTA_2_21_Attachment2.xls (for 2016) for the requested information. Kentucky Power's records are not maintained by height of pole. Predominantly all of the poles included in the attached files are wooden poles.

Witness: Tyler H. Ross

DATA REQUEST

KCTA_2_022 Please provide the following information regarding the number of cable attachments on KPCO poles as of the twelve months ending December 31, 2015 and December 31, 2016: (a) total number of cable attachments; (b) total number of cable attachments on a two-user pole as described in Administrative Order 251; (c) total number of cable attachments on a three-user pole as described in Administrative Order 251.

RESPONSE

a.

2015 - 141,873

2016 - 141,921

b.

2015 - 62,792

2016 - 62,819

c.

2015 - 79,081

2016 - 79,102

Witness: Stephen L. Sharp

DATA REQUEST

KCTA_2_023 Please provide the following information regarding pole attachment revenues for 2015 and 2016: (a) total dollars of pole attachment revenues; (b) pole attachment revenues associated with a two-user pole as described in Administrative Order 251; and (c) pole attachment revenues associated with a three-user pole as described in Administrative Order 251.

RESPONSE

Please refer to KPCO_R_KTCA_2_23_Attachment1.xlsx for the requested information.

Witness: Stephen L. Sharp

DATA REQUEST

KCTA_2_024 Please provide the information requested in the previous request (KCTA_2_023) for each of the preceding five years 2010 – 2014.

RESPONSE

Please refer to KPCO_R_KTCA_2_23_Attachment1.xlsx for the requested information.

Witness: Stephen L. Sharp

DATA REQUEST

KCTA_2_025 Identify the amount of makeready and other non-recurring charges paid to KPCO by cable operators in addition to the pole attachment revenues identified in response to 2_023 and 2_024 for the years 2010 to 2016.

RESPONSE

Please refer to KPCO_R_KCTA_2_25_Attachment1.xlsx for the requested information

Witness: Stephen L. Sharp