COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR: 1) AN ADJUSTMENT OF THE ELECTRIC RATES; (2) APPROVAL OF AN ENVIRONMENTAL ENVIRONMENTAL COMPLIANCE PLAN AND SURCHARGE MECHANISM; 3) APPROVAL OF NEW TARIFFS; 4) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES, AND (5) ALL OTHER REQUIRED APPROVALS AND RELIEF	)	**CASE NO. 2017-00321**

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY OFFICE OF THE ATTORNEY GENERAL

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

DECEMBER 2017

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DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Describe your education and professional experience.

A. I earned a Bachelor of Business Administration (“BBA”) degree in accounting and a Master of Business Administration (“MBA”) degree from the University of Toledo. I also earned a Master of Arts (“MA”) degree in theology from Luther Rice University. I am a Certified Public Accountant (“CPA”), with a practice license, Certified Management Accountant (“CMA”), and Chartered Global Management Accountant (“CGMA”). I am a member of numerous professional organizations, including the Society of Depreciation Professionals.

I have been an active participant in the utility industry for more than thirty years, initially as an employee of The Toledo Edison Company from 1976 to 1983 and thereafter as a consultant in the industry since 1983. I have testified as an expert witness on planning, ratemaking, accounting, finance, and tax issues in proceedings before regulatory commissions and courts at the federal and state levels on hundreds of occasions.

I have testified before the Kentucky Public Service Commission on numerous occasions, including base rate, environmental surcharge, fuel adjustment clause, resource acquisition, and merger and acquisition proceedings involving Kentucky Power Company (“KPC”), Kentucky Utilities Company (“KU”), Louisville Gas and Electric Company (“LG&E”), East Kentucky Power Cooperative, Inc. (“EKPC”), Big

Rivers Electric Corporation ("BREC"), Atmos Energy Corporation ("Atmos"), and Columbia Gas of Kentucky, Inc.[1]

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Office of the Attorney General of the Commonwealth of Kentucky ("AG").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: 1) summarize the AG revenue requirement recommendations, 2) address numerous issues that affect the Company's revenue requirement, including the recently enacted reduction in the federal corporate income tax rate, 3) quantify the effect on the revenue requirement of the return on equity recommendation provided by AG witness Mr. Richard Baudino, 4) address the Company's proposed new Environmental Surcharge Mechanism ("ESM"), and 5) address the Company's proposed new FERC Transmission Cost Reconciliation Mechanism ("Rider FTR").

Q. Please summarize your testimony.

A. I recommend that the Commission reduce the Company's base rates by at least

[1] My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

$16.014 million compared to the Company’s proposed base increase of $48.646 million. In the following table, I provide a summary of the AG recommendations compared to the Company’s request for a base rate increase. The AG recommendations regarding the cost of capital also will reduce the proposed Environmental Surcharge Mechanism (“ESM”) rider and Distribution Capital Investment (“DCI”) rider revenue requirements, if those riders are adopted, although I do not show the quantification of these reductions in the table.

Duke Energy Kentucky, Inc. Case No. 2017-00321 Base Revenue Requirement Summary of AG Recommendations For the Test Year Ended March 31, 2019 ($ Millions)	
Base Rate Increase Requested by Company	
Requested Base Increase	48.646
Operating Income Issues	
Include PJM Make Whole and Other Revenues Not Incl in Company's Revenue Forecast	(3.604)
Include Off-System Sales Margins to Reset PSM to $0	(3.826)
Reduce Replacement Power Expense	(4.069)
Reduce RTEP Charges	(0.410)
Reduce Vegetation Management Expense to Historic Levels	(2.407)
Reduce Planned Outage O&M Normalization	(1.203)
Remove Incentive Compensation Expense Tied to Financial Performance	(1.638)
Reduce Retirement Plan Expense	(1.584)
Increase AMI Levelization Adjustments	(1.368)
Reduce Carbon Management Amortization Expense to Reflect 10 Year Amortization Period	(0.201)
Reduce Amortization of East Bend Reg Asset to Reflect Lower O&M Expense Prior to Test Year	(0.406)
Reduce Depreciation Expense by Using ASL vs ELG Methodology	(6.939)
Reduce Depreciation Expense by Removing Terminal Net Salvage for Generating Units	(4.519)
Reduce Remaining Net Salvage Included in Depreciation Expense	(4.630)
Reduce Income Tax Expense to Reflect Reduction in Federal Rate	(10.255)
Reduce Income Tax Expense to Reflect Amortization of Excess Deferred Income Taxes	(6.054)
Reduce Income Tax Expense for Research Tax Credits	(0.102)
Capitalization Issues	
Reduce Capitalization for Loans to Other Duke Energy Affiliates from Sep 2018 to March 2019	(0.451)
Reduce Capitalization to Reflect Removal of East Bend O&M Reg Asset	(3.449)
Remove Deferred DSM Costs from Capitalization	(0.130)
Remove Deferred East Bend Coal Ash ARO Costs from Capitalization	(1.630)
Increase Capitalization to Reflect Reduction in Carbon Management Amortization Expense	0.018
Increase Capitalization to Reflect Reduction in Depreciation Expense-Use of ASL Methodogy	0.241
Increase Capitalization to Reflect Reduction in Depreciation Expense-Remove Terminal Net Salvage	0.157
Increase Capitalization to Reflect Reduction in Depreciation Expense-Remove Remaining Net Salvage	0.161
Cost of Capital Issues	
Reduce Return on Equity from 10.3% to 8.8%	(6.363)
Total AG Adjustments to DEK Request	**(64.661)**
Decrease After AG Adjustments	**(16.014)**

The AG does not oppose the ESM rider, but I make certain recommendations to ensure that only actual costs incurred are included in the ESM revenue requirement. The AG strongly opposes the proposed Rider FTR and the DCI rider. I respond to the proposed Rider FTR and Mr. Baudino responds to the Company's request for a DCI.

The remainder of my testimony is structured to address each of the issues on the preceding table followed by the ESM and FTR issues. The amounts that I cite throughout my testimony are electric only unless otherwise indicated as "total Company."

II. OPERATING INCOME ISSUES

A. <u>Include PJM Make Whole and Other Revenues In Revenue Forecast</u>

Q. Did the Company include RSG Rev - MISO Make Whole revenues in the test year other revenues?

A. No. The Company does not budget these revenues and for that reason did not include them in the test year other revenues, according to its response to AG discovery.[2] It should be noted that the account name refers to MISO, but the Company uses the account for PJM revenues.[3] The Company exited MISO in 2011 and has been a member of PJM since 2012.[4]

Q. What is the actual history of these revenues?

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[2] Company's response to AG 2-11. I have attached a copy of this response as my Exhibit___(LK-2).

[3] *Id.*

[4] Direct Testimony of John D. Swez at 15.

A. The Company actually recorded RSG Rev - MISO Make Whole revenues in account 456025 of $1.815 million in 2012, $0.787 million in 2013, $1.589 million in 2014, $1.389 million in 2015, $1.523 million in 2016, and $0.851 million in the first ten months of 2017 ($1.021 million annualized). The actual annual average is $1.254 million over the six-year historic period.[5]

Q. Is it reasonable to reflect RSG Rev – MISO Make Whole revenues of $0 in the test year?

A. No. The Company historically has received revenues each year. It is irrelevant whether the Company budgets the revenues. They should be included in the test year revenue requirement. The actual historic revenues provide a reasonable forecast for the test year.

Q. What is your recommendation?

A. I recommend that the Commission include the actual average revenues of $1.254 million in the test year revenue requirement.

Q. Are there other revenues that the Company failed to include in the test year?

A. Yes. The Company failed to include Scheduling & Dispatch revenues recorded in

[5] *Id.*

account 457105 and PJM Reactive Revenues recorded in account 457204. The Scheduling and Dispatch revenues were recorded in account 565 prior to February 2017 and the PJM Reactive Revenues were recorded in account 555 prior to December 2016.[6] Nevertheless, the Company actually recorded Scheduling & Dispatch Revenues of $0.207 million for the months February 2017 through October 2017 ($0.276 million annualized) and actually recorded PJM Reactive Revenues of $1.720 million ($2.064 million annualized) for the months January 2017 through October 2017.[7]

Q. What is your recommendation for the Scheduling & Dispatch Revenues and the PJM Reactive Revenues for the test year revenue requirement?

A. I recommend that the Commission include the $0.276 million annualized Scheduling & Dispatch Revenues from 2017 and the $2.064 million annualized PJM Reactive Revenues from 2017 in the test year revenue requirement.

B. Include Off-System Sales Margins and Reset Profit Sharing Margin Rider to $0

Q. Describe the Company's proposal for the off-system sales margins in the base revenue requirement and the Profit Sharing Margin rider.

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[6] Company's response to AG 2-11.
[7] *Id.*

A. The Company removed all off-system sales margins from the base revenue requirement. Instead, it proposes that all such margins be shared between the Company and its customers through the Profit Sharing Margin ("PSM") rider. The Company proposes to modify the existing PSM rider to include various additional expenses and revenues. The Company also proposes to modify the sharing structure so that the first $1 million no longer goes 100% to customers, but is shared between the Company and its customers. In addition, the Company proposes that all margins be shared 90% to customers and 10% instead of the present sharing of 75% to customers and 25% to the Company over the initial $1 million.[8]

Q. What are the forecast off-system sales margins in the test year?

A. The Company forecasts $3.815 million in off-system sales margins in the test year.[9]

Q. Should the forecast off-system sales margins be included in the PSM instead of in the base revenue requirement?

A. No. The Commission historically has included off-system sales margins in the base revenue requirement and contemporaneously reset the PSM or other sharing mechanism to $0. Thereafter, if the actual margins are more or less than the margins

[8] Direct Testimony of William Don Wathen Jr. at 12-18.
[9] Company response to AG 2-21. I have attached a copy of this response as my Exhibit___(LK-3).

included in the base revenue requirement, then the differences are shared through the PSM or other sharing mechanism.

Q. What is the effect of your recommendation?

A. The effect is a reduction of $3.836 million in the base revenue requirement. This reflects 100% of the Company's forecast off-system sales margins in the base revenue requirement and is consistent with resetting the PSM rider to $0.

C. <u>Reduce Replacement Power O&M Expense and Accept Request for Related Accounting Deferral Mechanism</u>

Q. Describe the Company's forecast of replacement power expense that cannot be recovered through the fuel adjustment mechanism.

A. The Company included $5.668 million in replacement power expense for the incremental fuel and other expense due to unplanned (forced) derates and outages that cannot be recovered through the fuel adjustment mechanism.[10] The Company forecast this expense using its GenTrader production cost model. It is related exclusively to East Bend and does not include any replacement power expense for the Woodsdale plant.[11]

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[10] Company's response to AG 1-11. I have attached a copy of this response as my Exhibit___(LK-4).

[11] *Id.*

Q. How does this forecast compare to the Company's actual replacement power expense for East Bend?

A. The forecast for the test year is wildly excessive compared to the actual replacement power expense for East Bend during the last three years. In fact, it is more than three times the average actual expense over the last three years. The actual replacement power expense was $1.294 million in 2015, $1.748 million in 2016, and $1.788 million in 2017 on an annualized basis. The Company has owned the entirety of the East Bend facility since December 31, 2014.[12]

Q. Is there any compelling reason why the Commission should include a forecast with an increase of this magnitude?

A. No. An increase of this magnitude does not pass any rational reasonableness test. This expense is inherently uncertain and unknown by its very nature. It hardly makes sense to rely on a production cost model to forecast this expense. First, because outages are either input (through deratings) or determined based on algorithms (through "random" forced outages), neither of which is sufficiently known or reliable to develop a forecast for ratemaking purposes. Second, because the replacement power cost depends on the methodology and/or the hourly distribution (pricing varies by hour) and the related assumptions regarding hourly pricing, neither of which can be sufficiently known or

[12] *Id.*

reliable to develop a forecast for ratemaking purposes.

Q. What is your recommendation?

A. I have two recommendations. First, I recommend that the Commission use the actual average replacement power expense for the years 2015-2017. This expense has been relatively constant over the three years and provides a reasonable forecast for the test year expense. Second, I recommend that the Commission approve the Company's request for accounting authority to defer replacement power expense greater than or less than the expense included in the base revenue requirement, subject to future review for ratemaking recovery.

In this manner, the Commission can reflect a reasonable replacement power expense in the base revenue requirement and the Company and its customers are protected if the actual expense is more or less through the opportunity to defer the difference between the actual expense and the expense included in the base revenue requirement.

Q. What is the effect of your recommendation?

A. The effect is a reduction in the replacement power expense of $4.058 million and a reduction in the revenue requirement of $4.069 million.

D. <u>Reduce RTEP Charge O&M Expense</u>

Q. Describe the forecast RTEP expense included in the test year revenue requirement.

A. The Company included $4.030 million in RTEP expense in its requested test year revenue requirement. It calculated this amount in several steps. First, it forecast the 2017 expense based on worksheets that are available on the PJM Interconnection website. Second, it calculated the escalation in the forecast 2017 expense over the actual 2016 expense as 7.7%. Third, it applied this 7.7% escalation to quantify the forecast 2018 expense and then applied the 7.7% escalation again to the forecast 2018 expense to quantify the forecast 2019 expense. Finally, it took 9 months of the forecast 2018 expense and 3 months of the forecast 2019 expense for the test year expense.[13]

Q. How does the forecast for 2017 compare to the Company's actual RTEP expense for 2017?

A. The forecast for 2017 is significantly more than the actual expense for 2017, which means that the escalation factor used by the Company and the resulting expenses are excessive, not only for 2017, but also for 2018 and 2019. In fact, the actual 2017 expense annualized is only 2.2% more than the actual 2016 expense, not the 7.7% reflected in the Company's forecast. In fact, the actual 2016 expense is only 0.7%

[13] Company's response to AG 1-14. I have attached a copy of this response as my Exhibit___(LK-5).

more than the actual 2015 expense. The average increase for 2016 and 2017 is only 1.4%. If this 1.4% is used to escalate the 2017 actual expense to forecast 2018 and 2019, the forecast RTEP expense will be much less than if the Company's forecast of 7.7% annual escalation each year after 2016 is used.[14]

Q. What is your recommendation?

A. I recommend that the Commission use the average actual RTEP escalation for the years 2016-2017. The Company's actual expense escalation provides a more reasonable escalation to forecast the test year expense than the Company's overstated 7.7% annual escalation.

Q. What is the effect of your recommendation?

A. The effect is a reduction in the RTEP expense of $0.409 million and a reduction in the revenue requirement of $0.410 million.

E. <u>Reduce Distribution Vegetation Management O&M Expense to Historic Levels</u>

Q. Describe the Company's request for vegetation management expense in the test year revenue requirement.

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[14] Company's response to AG 1-15. I have attached a copy of this response as my Exhibit___(LK-6).

A. The Company requests $4.480 million in vegetation management expense.[15] This forecast expense apparently is based on indicative bids issued by the Company.[16]

Q. How does the Company's request compare to the actual vegetation management expense in prior years?

A. It is wildly excessive. The actual expense in the years 2012 through 2016 ranged from a low of $1.774 million to a high of $2.309 million, with an average of $2.080 million. Perhaps more indicative is that the base year expense, a combination of actual expense and forecast expense, is only $1.601 million, even less than the average of the actual expense for the preceding five years.[17]

Q. What is your recommendation?

A. I recommend that the Commission use a more realistic forecast expense based on the actual average expense for the year 2012 through 2016.

Q. **What is the effect of your recommendation?**

A. The effect is a reduction in the vegetation management expense of $2.400 million and a reduction in the revenue requirement of $2.407 million.

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[15] Company's response to Staff 2-18. I have attached a copy of this response as my Exhibit___(LK-7).

[16] Direct Testimony of Anthony J. Platz at 18-19.

[17] Company's response to Staff 2-18.

F. <u>Reduce Normalized Planned Outage O&M Expense and Oppose Request for Related Accounting Deferral Mechanism</u>

Q. Describe the Company's normalized planned outage expense included in the test year revenue requirement.

A. The Company seeks $8.400 million in East Bend planned outage expense in the test year. The Company provided its calculation of this expense in its electronic workpapers as well as other support in response to Staff discovery.[18] The Company calculated a six-year average of actual and forecast planned outage expense for East Bend and Woodsdale on an inflation adjusted basis. The Company used the actual expense for years 2013 through 2016 and forecast expense for 2017 and 2018.[19] The Company did not use forecast expense for 2019, although it provided it in response to Staff discovery.[20]

Q. Is the Company's request reasonable?

A. No. It is excessive. The Company failed to include 2019 in the calculation of the average annual expense even though it included the forecast 2018 expense. Adding the forecast expense for 2019 to the average reduces the expense to $7.200 million

[18] Company's response to Staff 1-71 and Staff 2-23. I have attached a copy of the response to Staff 2-23 as my Exhibit___(LK-8).
[19] Company's response to Staff 1-71.
[20] Company's response to Staff 2-23.

from the requested $8.400 million.

Q. What is your recommendation?

A. I recommend that the Commission adopt an average expense that includes the forecast for 2019.

Q. What is the effect of your recommendation?

A. The effect is a reduction in the normalized planned outage expense of $1.200 million and a reduction in the revenue requirement of $1.203 million.

Q. Describe the Company's proposal for a new accounting deferral mechanism.

A. The Company seeks authorization to defer any actual planned outage expense that is more or less than the normalized planned outage expense included in the base revenue requirement.[21]

Q. Should the Commission approve this request?

A. No. The Company presently has a behavioral incentive to minimize the cost of planned outages. If actual planned outage expense is greater than the normalized planned outage expense included in the base revenue requirement, then the Company

[21] Direct Testimony of David L. Doss at 3-7.

cannot recover this excess. If the Commission adopts the Company's proposal, then this behavioral incentive will shift to encourage more expense, not less. Further, the normalized planned outage expense should be set to a reasonable amount based on actual historic expense and projected expense in the test year. This reasonable amount will provide the Company sufficient revenues to recover these expenses over multiple years.

G. <u>Remove Incentive Compensation Expense Tied to Financial Performance</u>

Q. Did the Company include compensation expense tied to financial performance?

A. Yes. The Company included $0.751 million in Short Term Incentive Plan ("STI") expense tied to the achievement of earnings per share ("EPS").[22] The Company also included $0.883 million in Long Term Incentive Plan ("LTIP") expense paid in the form of performance shares (70%) and restricted stock units (30%) tied primarily to the achievement of financial performance as measured by EPS and total shareholder performance ("TSP").[23,24]

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[22] Company's response to AG 1-18. I have attached a copy of the response as my Exhibit___(LK-9). The amounts reflected in O&M expense are detailed in this response and summarized in my electronic workpapers, which were filed in conjunction with my testimony.

[23] Company's response to AG 1-19. I have attached a copy of the response as my Exhibit___(LK-10). The amounts reflected in O&M expense are detailed in this response and summarized in my electronic workpapers, which were filed in conjunction with my testimony.

[24] Company's response to AG 1-22. I have attached a copy of the response as my Exhibit___(LK-11).

Q. Should this compensation expense tied to financial performance be removed from the revenue requirement?

A. Yes. First, the Commission historically has disallowed and removed all incentive compensation expenses from the revenue requirement that were incurred to incentivize the achievement of shareholder goals as measured by financial performance, not incurred to incentivize the achievement of customer and safety goals. For example, in its Order in Kentucky-American Water Company Case No. 2010-00036, the Commission disallowed incentive compensation expense tied to "financial goals that primarily benefited shareholders."[25] Likewise, in its order in Atmos Energy Corporation Case No. 2013-00148, the Commission stated "Incentive criteria based on a measure of EPS, with no measure of improvement in areas such as safety, service quality, call-center response, or other customer-focused criteria, are clearly shareholder-oriented. As noted in the hearing on this matter, the Commission has long held that ratepayers receive little, if any, benefit from these types of incentive plans. . . 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."[26] Thus, the STI and LTIP expense tied to EPS and total shareholder performance should be borne by shareholders, not customers.

Second, incentive compensation incurred to incentivize Duke Energy financial

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[25] Order in Kentucky American Water Company Case No. 2010-00036 at 14.
[26] Order in Atmos Energy Corporation Case No. 2013-00148 at 9.

performance also provides the Company's executives, managers, and employees a direct incentive to seek greater and more frequent rate increases from customers in order to improve Duke Energy Corporation's EPS and TSP. The greater the rate increases and revenues, the greater Duke Energy's EPS and TSP and the greater the incentive compensation expense. Thus, there is an inherent conflict between achieving lower rates for customers on the one hand and achieving greater financial performance for shareholders and greater incentive compensation for executives, managers, and other employees on the other hand. Thus, all such expenses should be allocated to shareholders, not to customers.

Finally, the Company's request to embed these expenses in the revenue requirement tends to be self-fulfilling. The additional revenues ensure that the expense is covered regardless of the Company's actual performance and regardless of its operational and safety performance. Thus, the expenses should be directly assigned to Duke Energy shareholders, not customers.

In summary, the Company's requests for recovery of STI and LTIP incentive compensation expense tied to EPS and total shareholder return fall clearly within the disallowance precedent and should be allocated to shareholders and not recovered from customers.

Q. What is the effect of your recommendation?

A. The effect is a reduction of $1.634 million in expense and a reduction of $1.638 million in the revenue requirement.

H. Increase AMI Benefit Levelization Adjustment

Q. Describe the Company's proposed AMI benefit levelization adjustment.

A. The Company is required to incorporate an AMI benefit levelization adjustment pursuant to the Stipulation approved by the Commission in Case No. 2016-00152. The Company calculated a reduction to expense of $2.321 million. In its calculation, the Company forecast annual levelized savings of $3.169 million based on the net present value annual savings forecast for the five years 2018 through 2022. The Company then reduced the $3.169 million for the $0.847 million savings that it asserts is included in the test year expense forecast without adjustment.[27]

Q. What is the purpose of the AMI benefit levelization adjustment?

A. The purpose of the AMI benefit levelization adjustment is to ensure that customers timely receive the benefits of the AMI deployment approved in Case No. 2016-00152.

[27] Refer to the Company's calculations on Sch_D2.26 included in the electronic workpapers provided in response to Staff 1-71.

Q. Did the Company estimate the AMI benefits levelization adjustment in Case No. 2016-00152?

A. Yes. The Company estimated these economic benefits in a confidential schedule provided in response to post-hearing data request Staff- PHDR-1-10 in Case No. 2016-00152. This same confidential schedule was provided by the Company in response to discovery in this rate case.[28] The Company used this schedule as the starting point for the calculation of the adjustment in this case.

Q. Did the Company modify the calculation of the AMI benefits levelization adjustment in this case compared to the calculation provided in Case No. 2016-00152?

A. Yes. The Company unilaterally shortened the benefits period from 15 years to 5 years. This had the effect of reducing the adjustment in this case.

Q. Is this appropriate?

A. No. The Commission should not depart from the methodology developed by the Company for this purpose in Case No. 2016-00152.

Q. What is the effect of calculating the AMI levelization adjustment using the 15-

[28] Company's confidential response to AG-DR-02-035(c).

year benefit period?

A. The effect is an increase in the AMI levelization adjustment of $1.364 million, to $3.685 million from the $2.321 million calculated by the Company.

I. <u>Reduce Retirement Plan Expenses</u>

Q. Describe the adjustments made by the Commission to reduce retirement plan expense in other recent cases.

A. The Commission reduced the retirement plan expense for both KU and LG&E in Case Nos. 2016-00370 and 2016-00371, respectively. In the KU case, the Commission stated:

> The Commission finds that, for ratemaking purposes, it is not reasonable to include both KU's Pre 2006 DDB plan contributions and KU's matching contributions to the 401(k) Plan for the following employee categories: exempt, manager, non-exempt, and officer and director personnel. Employees participating in the Pre 2006 DDB Plan enjoy generous retirement plan benefits, making the matching 401(k) Plan amounts excessive for ratemaking purposes. Accordingly, the Commission denies for recovery 401(k) Plan matching contributions in the amount of $1,720,383 before gross-up.[29]

Similarly, the Commission reduced the retirement plan expense for Cumberland Valley Electric, Inc. in Case No. 2016-00169. In that case, the Commission stated:

[29] Order dated June 22, 2017 in Case No. 2016-00370 at 14-15.

> The Commission believes all employees should have a retirement benefit, but finds it excessive and not reasonable that Cumberland Valley continues to contribute to both a defined benefit pension plan as well as a 401(k) plan for salaried employees. The Commission will allow Cumberland Valley to recover only the costs of the more expensive defined benefit plan for the salaried employees and the 401(k) plan for union employees. Accordingly, the Commission will remove for ratemaking purposes Cumberland Valley's test year 401(k) contributions for salaried employees.[30]

Q. What is the effect of a similar adjustment in this proceeding?

A. The effect is a reduction in retirement plan expense of $1.580 million and a reduction in the revenue requirement of $1.584 million. This includes the retirement plan expense incurred directly by the Company for its employees and the charges from affiliates for their employees.[31]

J. Reduce Carbon Management Amortization Expense to Reflect 10-Year Amortization Period

Q. Describe the Company's request for amortization of the Carbon Management Research regulatory asset.

A. The Company deferred $2.000 million it incurred to fund carbon management research by the Carbon Management Research Group ("CMRG").[32] The Company sought and

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[30] Order dated February 6, 2017 in Case No. 2016-00169 at 10.

31 Company's response to Staff 2-5. I have attached a copy of this response as my Exhibit___(LK-12).

[32] WPD 2.31a.

obtained authorization from the Commission to defer these costs for accounting purposes.[33] The Company seeks to recover $0.400 million in amortization expense based on an amortization period of 5 years.[34] The regulatory asset, net of ADIT, is included in capitalization.

Q. Is the proposed 5-year amortization period appropriate?

A. No. The Company was one of four applicants in Case No. 2008-00308 wherein they sought authority to defer their funding contributions to CMRG and the Kentucky Consortium for Carbon Storage ("KCCS"), although the Company only sought such authority for funding contributions to CMRG. In their joint application, they stated their intent to seek authority to amortize the CMRG regulatory asset over 10 years in a subsequent base rate case as follows:

> 18. The Applicants propose that their commitments for these payments be treated as regulatory assets to be deferred until recovery is provided within the next base rate case of each applicant, at which time the regulatory assets will be amortized over the life of each project: four years in the case of KCCS and ten years with respect to payments to CMRG.

On that basis alone, the Commission should use a 10-year amortization period instead of the proposed 5-year amortization period.

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[33] Order in Case No. 2008-0308.
[34] WPD 2.31a.

Q. Is there another reason why the Commission should use a 10-year amortization period?

A. Yes. The Company's revenue requirement reflects the full amount of the regulatory asset in capitalization at March 31, 2018. As the regulatory asset is amortized, the related capitalization and the revenue requirement decline. However, the Company's revenues do not decline to match the reduction in the revenue requirement until there is another base rate case and base rates are reset. Thus, the Company retains the savings resulting from the decline in the revenue requirement until base rates are reset. Although that is unavoidable unless the Commission uses a levelized (annuitized) methodology like that proposed by the Company for the East Bend O&M expense regulatory asset, the Commission can minimize the over-recovery by using a longer amortization period.

Q. What is the effect of using an amortization period of 10 years for the Carbon Management Research regulatory asset?

A. The effect is a reduction in the revenue requirement of $0.183 million, comprised of a $0.201 million reduction due to the reduction of $0.200 million in amortization expense, and an increase in the return on rate base of $0.018 million.[35]

[35] The quantifications of these amounts are reflected in my electronic workpapers, which were filed along with my testimony.

K. <u>Reduce Amortization of East Bend O&M Expense Regulatory Asset to Reflect Lower O&M Expense Prior to Test Year</u>

Q. Describe the Company's East Bend deferred O&M expense regulatory asset.

A. The Company seeks recovery of $39.162 million as of March 31, 2018 for this regulatory asset.[36] The Company has recorded these deferrals on its accounting books since January 2015. The regulatory asset reflects actual deferrals through December 2016 and forecast deferrals since January 2017.[37]

The Commission authorized the Company for accounting purposes to defer the increase in East Bend O&M expense resulting from its acquisition of the remaining 31% minority interest offset by the reduction in Miami Fort 6 ("MF 6") O&M expense due to the planned retirement of that unit. In addition, the Commission authorized the Company to defer carrying charges on the deferred O&M expense at its weighted average cost of debt.[38]

Although the Commission authorized these deferrals for accounting purposes in conjunction with approval of a Stipulation between the Company and the AG, it did not authorize future rate recovery. The Stipulation states: "Cost recovery for the foregoing accounting treatments shall be considered in the course of a future rate

[36] WPD 2.31a.
[37] Company's response to AG 1-23, which provides the monthly calculation of the East Bend O&M deferral, including the incremental East Bend O&M expenses, MF 6 base offset, and the carrying costs on the deferrals. I have attached a copy of the response as my Exhibit___(LK-13).
[38] Order in Case No. 2014-00201.

proceeding."[39] This is the Commission's first opportunity in a base rate proceeding to review the deferrals and determine the appropriate rate recovery.

Q. Describe the Company's proposed recovery of the East Bend O&M expense regulatory asset in this proceeding.

A. The Company proposes an amortization expense of $4.812 million based on a levelized (annuitized) recovery of the $39.162 million regulatory asset over ten years using the Company's forecast cost of debt.[40] Although it included the debt return in the levelized amortization expense, it failed to reduce capitalization to remove the return on this regulatory asset. I address this issue in greater detail in the Capitalization Issues section of my testimony.

Q. Describe how the Company calculated the deferral balance at the beginning of the test year and how this affects the resulting amortization expense.

A. The Company forecasted the deferred O&M expense at March 31, 2018, the day before the beginning of the test year. It did so by adding the actual East Bend O&M expense deferred in excess of the MF 6 "base" through December 2016 to its forecast of East Bend O&M expense in excess of the MF 6 base from January 2017 through March 2018. The Company also applied the average cost of debt to the actual deferrals

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[39] *Id.*
[40] WPD 2.31a.

each month through December 2016 and to the forecast deferrals each month from January 2017 through March 2018 and added these carrying charges to the deferral as well.[41]

Q. Are the forecast deferrals from January 2017 through March 2018 reasonable?

A. No. They are excessive. Consequently, the forecast East Bend O&M expense regulatory asset at March 31, 2018 is excessive and the levelized amortization expense is excessive. More specifically, the Company's actual historic East Bend O&M expense has been much less than the forecast O&M expense for these 15 months. The Company forecast a monthly deferral of O&M expenses, excluding the debt return, of $0.945 million. However, the actual deferrals for the months January 2017 through October 2017 are much less and the average actual monthly deferrals for the twelve months ending October 2017 also are much less than the Company's forecast for the months November 2017 through March 2018, as shown on the following table.

[41] Company's response to AG 1-23.

East Bend O&M Monthly Deferrals
Actual vs Forecast
($ Millions)

Month	Actual Deferral		Projected Deferral	Actual Less Than Projected
Jan-17	0.721		0.945	(0.223)
Feb-17	0.656		0.945	(0.289)
Mar-17	0.865		0.945	(0.080)
Apr-17	0.543		0.945	(0.402)
May-17	1.146		0.945	0.201
Jun-17	0.674		0.945	(0.271)
Jul-17	0.727		0.945	(0.217)
Aug-17	0.727		0.945	(0.217)
Sep-17	0.510		0.945	(0.434)
Oct-17	0.748		0.945	(0.196)
Nov-17	0.729	*	0.945	(0.216)
Dec-17	0.729	*	0.945	(0.216)
Jan-18	0.729	*	0.945	(0.216)
Feb-18	0.729	*	0.945	(0.216)
Mar-18	0.729	*	0.945	(0.216)
Total	10.962		14.170	(3.209)

* Actual Deferral Amounts for the Months November 2017 through March 2018 Represent the Average of the Prior 12 Months Actuals

Q. What is your recommendation?

A. I recommend that the Commission reduce the regulatory asset to reflect the actual deferrals through October 2017 and to revise the forecast for the months November 2017 through March 2018 so that they are consistent with the actual monthly deferrals for the twelve months ending October 2017. In this manner, the forecast is updated for the actual deferrals through October 2017 and for the most current actual monthly deferrals as a reasonable proxy for the remaining forecast months through March 2018.

Q. Have you quantified the effect of your recommendation?

A. Yes. The effect is a reduction in the levelized expense of $0.405 million and a reduction in the revenue requirement of $0.406 million.[42] This calculation reflects the reductions in the deferred O&M expenses as well as the reductions in the related deferred carrying charges. The revised regulatory asset is $35.870 million at March 31, 2018 and the revised levelized expense is $4.408 million.

L. <u>Reduce Depreciation Expense to Reflect ALG Instead of ELG Procedure for Calculation of Depreciation Rates</u>

Q. Describe the Company's request to change its depreciation rates.

A. The Company proposes to change its depreciation rates effective at the beginning of the test year to reflect the results of the depreciation study performed by Mr. John Spanos based on a study date of December 31, 2016. The present depreciation rates were set forth in a Stipulation that was approved by the Commission in Case No. 2006-

[42] The quantifications of these amounts are reflected in my electronic workpapers, which were filed along with my testimony. I used the Company's formula reflected in Schedule D-2.31 WPa to calculate the levelized amortization expense based on the adjusted regulatory asset at March 31, 2018.

00172.[43]

The proposed depreciation rates are based on the Equal Life Group ("ELG") procedure instead of the Average Life Group ("ALG") procedure, the dominant procedure used by other electric utilities, including all other electric utilities in the Commonwealth. The AG opposed the ELG procedure in Case No. 2006-00172. Although Mr. Spanos proposes the ELG procedure, he also provided the depreciation rates using the ALG procedure in response to AG discovery.[44]

Q. How do the ELG and ALG depreciation rates resulting from Mr. Spanos' study compare to the present depreciation rates?

A. The proposed depreciation rates using either the ELG or the ALG procedures vary significantly from the present depreciation rates. The Company provided a comparison of the proposed depreciation rates using the ELG procedure to the present depreciation rates in response to AG discovery.[45] The Company's proposed changes in the depreciation rates using the ELG procedure result in an increase in the test year depreciation expense of $5.936 million.[46]

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[43] Stipulation Attachment 2 to Commission Order in Case No. 2006-00172. Confirmed in Company's response to AG 1-34. I have attached a copy of this response as my Exhibit___(LK-14).

[44] Company response to AG 1-35. I have attached a copy of the response as my Exhibit___(LK-15).

[45] Company's response to AG 1-36. I have attached a copy of the response as my Exhibit___(LK-16).

[46] Company's response to AG 1-39. I have attached a copy of the response as my Exhibit___(LK-17).

The Company also provided depreciation rates using the ALG procedure in response to AG discovery. The proposed changes in the depreciation rates revised to reflect the ALG procedure results in a reduction in the test year depreciation expense compared to the proposed ELG procedure of $6.920 million, or a reduction compared to present rates of $0.984 million, assuming no changes to the parameters (assumptions) reflected in the depreciation study.

As is typically the case, the ELG depreciation rates are significantly greater than the ALG rates using similar depreciation parameters (interim retirement curves, cost of removal, gross salvage, average service lives).

Q. Does the Company recover the entirety of its gross plant balances through depreciation expense regardless of whether the ELG or ALG procedure is used?

A. Yes. The difference is in the timing of the recovery. Under the ELG procedure, particularly if it is adopted after the utility historically has used the ALG procedure, the capital recovery periods are accelerated and shortened, and thus, the depreciation rates are greater than if the ALG procedure is used and/or maintained. This result is borne out by the greater ELG depreciation rates and expense compared to the ALG rates and expense resulting from the Company's depreciation study.

Q. Why is that?

A. The ELG procedure utilizes a statistical technique that stratifies plant account data into vintage year equal life groups and depreciates each equal life group over its remaining life so that the plant balance in each group is fully depreciated at the end of its life. In contrast, the ALG procedure depreciates the entire plant account over the remaining life of the account, which is revised each time a depreciation study is performed. The ELG procedure effectively accelerates the depreciation of the plant compared to the ALG procedure.

Q. Is the ELG procedure more accurate than the ALG procedure?

A. No. First, at its very essence, the ELG procedure is simply an alternative statistical methodology to determine the timing of depreciation expense and recovery. The result of the ELG procedure is to accelerate recovery in the early years and decelerate recovery in the latter years compared to the ALG procedure on vintage year plant balances, all else equal.

Second, although the ELG procedure requires a more refined stratification of the data, this stratification is itself the result of judgment and assumptions, which are subject to the discretion of the analyst and easily biased, whether intentionally or unintentionally. Thus, the claimed precision is illusory at best and biased at worst.

Third, both the ELG and ALG procedures require estimates of all parameters, which inherently are subject to change based on actual results each time another depreciation study is performed. For example, the interim retirement curves frequently change from depreciation study to depreciation study, which then requires a recalibration of the equal life groups and belies the alleged accuracy of the ELG procedure.

Q. Should the Commission adopt the Company's proposal to use the ELG procedure?

A. No. The Commission should adopt the ALG procedure. There is no compelling reason to adopt the ELG procedure. There is no compelling reason to unnecessarily increase depreciation rates and expense. The ALG procedure is fully compensatory and provides the Company full recovery of its gross plant costs, which includes the time value of the recovery because gross plant costs less accumulated depreciation is included in rate base and earn a return until they are depreciated.

The ALG procedure is as accurate as the ELG procedure, but smooths the data so that the depreciation rates for the group tend to remain constant, all else equal, over the service life compared to the ELG procedure, which results in greater depreciation rates initially, but then lower depreciation rates as each equal life group is assumed fully retired. The ALG procedure provides a normalized depreciation expense for ratemaking purposes, all else equal.

Q. What is the effect of your recommendation to reject the ELG procedure and instead use the ALG procedure?

A. The effect is a reduction in the revenue requirement of $6.698 million, comprised of the reduction in depreciation expense of $6.939 million (grossed-up from $6.920 million), offset by the return on the increase in capitalization of $0.241 million due to the reduction in accumulated depreciation.[47]

M. <u>Overview of Terminal and Interim Net Salvage and Effects on Depreciation Rates of Alternative Recovery Approaches</u>

Q. Describe terminal and interim net salvage and alternatives for recovery.

A. Terminal net salvage refers to the cost of removal, less salvage income, to dismantle production facilities, and to restore the site. Interim net salvage refers to all other cost of removal, less salvage income, to retire and remove an asset from service. Actual net salvage is always used to reduce accumulated depreciation (for net negative salvage, where cost of removal exceeds salvage income) or to increase accumulated depreciation (for net salvage, where salvage income exceeds cost of removal).

Q. What are the recovery alternatives?

A. There are three approaches to reflect net salvage in depreciation rates. The first is to estimate and preemptively reflect future net salvage in the depreciation rates and expense. This is the approach proposed by the Company in this proceeding. If there

[47] The quantifications of these amounts are reflected in my electronic workpapers, which were filed along with my testimony.

is net negative salvage (cost of removal), then the estimated future net salvage is added to the net book value to determine the amount that must be recovered, which then is divided by the average life for the assets to calculate the depreciation expense. This calculated depreciation expense is then divided by gross plant to calculate the depreciation rates. This approach results in greater depreciation rates in the earlier years of asset lives and lower depreciation rates in the latter years of asset lives compared to the second or third ways, all else equal.

The second approach is to include no estimate of future net salvage in depreciation rates. Instead, the actual terminal net salvage on production plant is deferred if and when it is incurred and then recovered over an appropriate amortization period. The actual interim net salvage is included in the depreciation rates and expense on a lagged basis. This occurs through the calculation of net book value, which reflects all actual net salvage, but does not include any estimated future net salvage. This approach results in lower depreciation rates in the earlier years of asset lives and greater depreciation rates in the latter years of asset lives compared to the first or third approaches, all else equal.

The third approach is a combination of the first and second approaches. Similar to the second approach, the actual terminal net salvage on production plant is deferred if and when it is incurred and then recovered over an appropriate amortization period. The actual interim net salvage is included at a level that reflects recent actual net salvage rather than an estimate of future net salvage. This third approach provides relatively contemporaneous recovery of actual net salvage rather than the preemptive recovery in the first approach or the lagged recovery of the second approach. This approach results in lower depreciation rates in the earlier years of asset lives and greater depreciation rates in the latter years of asset lives compared to the first approach, and greater depreciation rates in the earlier years of asset lives and lower depreciation rates in the latter years of asset lives compared to the second approach, all else equal.

Q. Does the utility recover all its gross plant costs, including net salvage, under all three approaches that you described?

A. Yes. The utility recovers all its plant costs, including net salvage, under all three approaches that I described. However, the timing of the recovery differs significantly. The first approach provides the most accelerated recovery based on estimated future net salvage. The second approach provides lagged recovery based on actual net salvage. The third approach provides lagged recovery based on actual terminal net salvage for production plant dismantling and site restoration, but contemporaneous recovery of interim net salvage.

N. <u>Reduce Depreciation Expense to Remove Terminal Net Salvage from Production Plant Depreciation Rates</u>

Q. Describe the terminal net salvage included by the Company in its proposed production plant depreciation rates and expense.

A. The Company included $4.506 million in its proposed depreciation expense for terminal net salvage (forecast cost of removal exceeds salvage income).[48] The Company's proposal to include terminal net salvage increased the depreciation rates for the production plant accounts by an average of 18.3%.

Mr. Spanos relied on the terminal net negative salvage estimates initially developed by Mr. Jeffrey Kopp of Burns & McDonnell,[49] which either he or the Company escalated by 2.5% annually until the estimated retirement dates of the East Bend and Woodsdale production plant accounts.[50]

Q. Is the Company's proposed recovery of future terminal net negative salvage for the production plant accounts appropriate?

A. No. The Commission should reject the Company's request to recover forecast costs that are not known with reasonable certainty today. The Company's request inherently adopts a default assumption that the production facilities will be dismantled and the site restored even though that often is not the economic alternative when compared to

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[48] The quantifications of these amounts are reflected in my electronic workpapers, which were filed along with my testimony.

[49] Direct Testimony of Jeffrey Kopp.

[50] Company's response to AG 1-37. I have attached a copy of the response as my Exhibit___(LK-18). The Burns & McDonnell and the escalated decommissioning cost estimates for East Bend and Woodsdale are shown on Attachment JJS-1 page 211 of 346 of the depreciation study.

"retirement in place."[51] The Company's request requires the Commission to preemptively and prematurely decide today the scope of future dismantling activities and site restoration that may be necessary or reasonable when the Company's generating units are retired decades in the future. The Company's request also requires the Commission to guess at the cost of the future dismantling activities and site restoration that may be necessary or reasonable.

Instead, the Commission should adopt a default assumption of "retirement in place" unless and until the generating units actually are retired or near retirement. This assumption should be changed only after the Company files, and only if the Commission approves, a dismantling and site restoration plan, including the estimated cost at that time. The Company would be required to make a filing and demonstrate that the dismantling and site restoration plan was necessary and that the estimated cost was reasonable.

If the Commission approves a dismantling and site restoration plan, then the Company would be allowed to defer the actual and prudent costs incurred pursuant to the approved plan and recover those costs prospectively.

Q. Why is the assumption of "retirement in place" a better approach?

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[51] Retirement in place refers to minimal post-retirement dismantling activities necessary to stabilize the facilities for safety purposes and to secure the site.

A. First, this approach establishes a default assumption of "retirement in place" rather than the Company's preemptive and premature assumption of dismantlement and site restoration and the related scope and cost of those activities.

Second, it requires the Company to demonstrate that dismantling and site restoration, the scope of such activities, and the estimated costs are necessary and reasonable after or near the actual retirement of the generating units.

Third, it ensures that costs are incurred only if dismantling and site restoration is necessary and the Commission approves the scope of the activities after or near the retirement date.

Fourth, it minimizes costs to customers during the operation and after the retirement of the production facilities.

Fifth, it ensures that only actual costs are recovered from customers after they are incurred. This avoids the guesswork of estimates developed and recovery of these estimates through depreciation rates decades before the generating units are retired, let alone dismantled and the site restored.

Q. If the Commission does not remove the terminal net negative salvage from the proposed production plant depreciation rates and expense, do you have another recommendation?

A. Yes. If the Commission allows terminal net salvage, then, at a minimum, it should remove the 2.50% annual escalation rate applied to the terminal net salvage estimate developed by Burns & McDonnell. This escalation methodology improperly "front-loads" recovery of an uncertain estimate of future costs in future dollars, which also is uncertain. The Company's proposed escalation assumes that there will be no changes in the physical dismantling and site restoration approach assumed by Burns & McDonnell, no efficiencies from technology, equipment and disposal advances, and no improvements in productivity, any of which could offset future inflation in costs.

Further, the use for 2017 ratemaking purposes of estimated 2041 future dollars for East Bend and 2032 future dollars for Woodsdale[52] is an inherent mismatch and forces today's customers to subsidize future customers. If the cost estimate or actual cost escalates in future years, then the increases, to the extent they are reasonable and prudent, can be reflected in periodic revisions and updates to depreciation rates and expense.

Q. What is the effect of your recommendation to remove the cost of future dismantling and site restoration from the depreciation rates and expense for the production plant accounts?

A. The effect is a reduction in the revenue requirement of $4.362 million, comprised of the reduction in depreciation expense of $4.519 million (grossed-up from $4.506 million), offset by the return on the increase in capitalization of $0.157 million due to

[52] Schedule V-III-4 in depreciation study provides probable retirement dates of 2041 for East Bend and 2032 for Woodsdale.

the reduction in accumulated depreciation. The reduction in depreciation expense is in addition to the reduction from using the ALG procedure instead of the ELG procedure.[53]

O. <u>Reduce Other (Interim) Net Salvage Included in Depreciation Expense to Reflect Contemporaneous Recovery</u>

Q. Describe the interim net salvage included in the Company's proposed depreciation rates and expense.

A. The Company included interim net salvage based on forecasts of future cost of removal and salvage income, or the "first approach" that I previously described. Mr. Spanos calculated historic net salvage divided by historic retirements and then applied this ratio to the estimated interim retirement portion of the production plant accounts and the entirety of the transmission and distribution plant accounts.

For example, assume that the average annual interim retirements are $100,000 and the average annual interim net salvage is negative $20,000. Assume further that the plant balance in the account is $100 million, accumulated depreciation is $30 million, and the average service life is 30 years. Under the Company's "first approach" methodology, the interim net salvage would be negative 20%. This would

[53] The quantifications of these amounts are reflected in my electronic workpapers, which were filed along with my testimony.

be applied to the entire $100 million in the plant account to increase the depreciable, or recoverable, balance to $90 million (gross plant of $100 million plus $20 million net negative salvage less $30 million accumulated depreciation). The depreciation rate would be 3.00%, of which 2.33% is pure depreciation and 0.67% is interim net salvage. Depreciation expense would be $3 million, of which $2.333 million is pure depreciation and $0.667 million is interim net salvage.

Q. Is the Company's methodology appropriate?

A. No. This "first approach" methodology front-loads forecasted costs based on limited data applied to the interim retirement portion of the production plant accounts and the entirety of the transmission and distribution plant accounts. It preemptively recovers costs that have not and may not be incurred. It overstates depreciation rates and expense.

Q. What is your recommendation?

A. I recommend the "third approach" methodology that I previously described. This methodology calculates the interim net salvage based on the same historic data used by the Company, but uses the average annual historic interim net salvage dollars divided by the interim retirement portion of the production plant account and the entirety of the transmission and distribution plant accounts rather than the annual historic retirements. This methodology assumes that interim net salvage will continue at the same dollar amount until the next depreciation study. As such, it provides contemporaneous recovery of the net salvage dollars as I previously described.

For example, under the assumptions that I used to illustrate the Company's "first approach" methodology, the "third approach" methodology includes $20,000 of interim net salvage in the annual depreciation rate and expense. This results in a depreciation rate of 2.35%, of which 2.33% is pure depreciation and .02% is interim net salvage. Depreciation expense would be $2.350 million, of which $2.333 million is pure depreciation and $0.020 million is interim net salvage.

Q. What is the effect of your recommendation to reject the Company's "first approach" and instead use the "third approach" methodology for interim net salvage?

A. The effect is a reduction in the revenue requirement of $4.469 million, comprised of the reduction in depreciation expense of $4.630 million (grossed-up from $4.617 million), offset by the return on the increase in capitalization of $0.161 million due to the reduction in accumulated depreciation. The reduction in depreciation expense is in addition to the reduction from using the ALG procedure instead of the ELG procedure and in addition to the reduction from removing terminal net salvage from the production plant accounts.[54]

[54] The quantifications of these amounts are reflected in my electronic workpapers, which were filed along with my testimony.

P. Reduce Income Tax Expense to Reflect Reduction in Federal Corporate Income Tax Rate

Q. Please describe the recently enacted reductions in the federal corporate income tax rate.

A. The President recently signed legislation that reduced the federal corporate income tax rate from 35% to 21% effective January 1, 2018.

Q. What effects does the reduction in the federal corporate income tax rate have on the revenue requirement?

A. There are three direct effects based on the Company's income tax expense and ADIT. First, there is a reduction in current and deferred federal income tax expense included in the test year. Second, there is a reduction in deferred income tax expense to reflect the amortization (through negative deferred income tax expense) of the excess accumulated deferred income taxes ("ADIT"). Third, there is a reduction in the gross revenue conversion factor.

In addition, there are three similar indirect effects from affiliate charges that include an income tax component (based on an equity return applied to "rate base" and an ADIT component used to calculate rate base). These effects primarily are included in charges from DEBS and DEO.

Q. Describe the first effect, the reduction in current and deferred federal income tax expense included in the test year.

A. The current and deferred federal income tax expense is simply scaled down to reflect the 21% federal income tax rate instead of the 35% rate used to calculate the expense in the test year. The federal income tax rate is reduced by 40% ((35% - 21%) / 35%). Consequently, the related current and deferred federal income tax expense is reduced by 40%, all else equal.

Q. Describe the second effect, the amortization of the excess ADIT.

A. The reduction in the federal income tax rate results in a reduction of the future net income tax liabilities recorded in the asset and liability ADIT accounts (190, 281, 282, and 283). The reduction in the federal income tax rate permanently reduces these future tax liabilities. The reduction in the net ADIT liability is termed "excess" ADIT and is considered a regulatory liability for generally accepted accounting principles ("GAAP"), although it may continue to be recorded as ADIT for FERC Uniform System of Accounts ("USOA") accounting purposes. The excess ADIT will be amortized as a negative deferred tax expense without a concurrent increase in current income tax expense, which means that it increases operating income and reduces the revenue requirement, all else equal.

Q. Describe the third effect, the reduction in the gross revenue conversion factor.

A. The reduction in the federal income tax rate results in a reduction in the income tax component of the gross revenue conversion factor ("GRCF"). The GRCF is used to gross-up the test year operating income deficiency to calculate the revenue deficiency.

Q. Have you quantified the reduction in the revenue requirement to reflect the direct effects on the Company from the new income tax rate of 21%?

A. Yes. The reduction in the base revenue requirement is $16.309 million. This consists of the reduction of $10.255 million in the revenue requirement due to the reduction in federal income tax expense and a reduction of $6.054 million in the revenue requirement due to the amortization of the excess ADIT of $95.651 million.[55]

Q. Should the Commission also reflect the indirect effects on the Company from affiliate charges that include an income tax component and an ADIT component?

A. Yes.

Q. Should the Commission also reflect the income tax rate of 21% in the revenue requirement for all riders where there is an equity return and income tax

[55] The quantifications of these amounts are reflected in my electronic workpapers, which were filed along with my testimony.

expense?

A. Yes. That would include the proposed environmental surcharge rider as well as any present and/or future riders that include an income tax expense component.

Q. <u>Reduce Income Tax Expense for Research Tax Credits</u>

Q. Describe the research tax credit used by the Company to reduce its actual income tax expense.

A. The Company historically has claimed the research tax credit as a reduction to its current income tax expense. It claimed research tax credits against its electric income tax expense of $.068 million in 2012, $0.039 million in 2013, $0.046 million in 2014, $0.058 in 2015, and $0.226 million in 2016. It forecasts $0.086 million in 2017, $0.088 million in 2018, and $0.091 million in 2019. It forecasts $0.076 million in the test year.[56]

Q. Did the Company reflect its forecast research tax credit as a reduction to the forecast test year income tax expense in its filing in this proceeding?

A. No. Consequently, the test year income tax expense and the revenue requirement are overstated.

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[56] Response to AG 2-5. I have attached a copy of this response as my Exhibit___(LK-19).

Q. Has the Company acknowledged that its failure to include the research tax credit in its filing in this proceeding is an error that should be corrected?

A. Yes. The Company stated in response to AG discovery that the research tax credit "was erroneously excluded from the calculation of tax expense in the test year revenue requirement."[57]

Q. What is the effect on the revenue requirement of correcting this error?

A. The effect is a reduction of $0.102 million, assuming that the newly enacted 21% federal income tax rate is reflected in the income tax expense and gross revenue conversion factor. This is based on the Company's forecast research tax credit of $0.076 million grossed-up for income taxes based on the new 21% federal income tax rate.

III. CAPITALIZATION ISSUES

A. Reduce Capitalization for Loans Made to Other Duke Energy Affiliates

Q. Describe the Company's use of the Duke Energy Money Pool.

A. The Company is a member of the Duke Energy Money Pool. It borrows from the Money Pool to meet short-term cash requirements and lends to the Money Pool when it has surplus cash balances.[58]

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[57] *Id.*
[58] Company's response to AG 2-9. I have attached a copy of the response as my Exhibit___(LK-20).

Q. How are the borrowings and investments in the Money Pool recorded and what effect does this have on the capitalization used for ratemaking purposes?

A. When the Company is a borrower from the Money Pool, it reflects the borrowings as short-term debt, which it includes in capitalization for ratemaking purposes. When it is a lender to (investor in) the Money Pool, it reflects the receivables as short-term investments on the asset side of the balance sheet, which it does not reflect as a reduction to capitalization for ratemaking purposes.

Q. If short-term investments are recorded on the asset side of the balance sheet and are not used to reduce capitalization for ratemaking purposes, is this a problem?

A. Yes. If the Company is a lender to (investor in) the Money Pool, then its capitalization funds that investment, just as it funds plant and other assets. However, the Company should not include a return on these short-term investments in the revenue requirement. These investments are loans to other Duke Energy affiliates. The Company would not be allowed a return on these short-term investments if the Commission used rate base for the return component of the revenue requirement. Similarly, the Company should not be allowed a return on these short-term investments when capitalization is overstated to reflect the funding of these investments.

Q. Does the Company forecast that it will have short-term investments in the Money Pool during the test year?

A. Yes. It forecasts that it will have short-term investments in all months September 2018 through March 2019. The Company acknowledges that it will be a lender (investor) to the Money Pool starting in September 2018, primarily due to the issuance of long-term debt in September 2018,[59] all of which is included in the Company's proposed capitalization.[60]

Q. What is the 13-month average of these short-term investments?

A. The 13-month average is $5.126 million. That means that the 13-month average capitalization is overstated by $5.126 million.

Q. What is the effect of removing the short-term investments from capitalization?

A. The effect is a reduction in the revenue requirement of $0.451 million, assuming the Company's requested return on capitalization, but revised to reflect the gross-up at the new federal income tax rate of 21%.[61]

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[59] Company's response to AG 2-9.

[60] Sch_J3 – Forecast included in its electronic schedules and workpapers provided in response to Staff 1-71.

[61] The quantifications of these amounts are reflected in my electronic workpapers, which were filed along with my testimony.

B. <u>Reduce Capitalization to Reflect Removal of East Bend O&M Expense Regulatory Asset</u>

Q. Did the Company remove the East Bend O&M Expense Regulatory Asset from capitalization?

A. No. This is an error in the Company's filing. The Company included a debt only rate of return in the levelized amortization expense for the East Bend O&M expense regulatory asset and in the revenue requirement. The Company also included the regulatory asset in capitalization and included the grossed-up return at the weighted cost of capital in the revenue requirement. The Company is entitled to only one return on the regulatory asset, not two.

Q. What is your recommendation?

A. I recommend that the Commission remove the East Bend O&M expense regulatory asset from capitalization.

Q. Have you quantified the effect of correcting this error?

A. Yes. The effect is a reduction in the revenue requirement of $3.449 million, assuming the Company's requested return on capitalization, but revised to reflect the gross-up at the new federal income tax rate of 21%.[62]

[62] The quantification of these amounts are reflected in my electronic workpapers, which were filed

C. Remove DSM Regulatory Asset from Capitalization

Q. Did the Company remove the DSM regulatory asset from capitalization?

A. No. This is an error. This regulatory asset is the result of the Company's under recovery of its DSM costs through the DSM rider. The Company recovers its DSM costs through the DSM rider, including any over or under recovery. All DSM costs should be removed from the base revenue requirement.

Q. Does the Company agree that the DSM costs should be removed from the base revenue requirement?

A. The Company agrees that all revenues and expenses should be removed, according to its response to AG discovery. The Company stated:

> The Duke Energy Kentucky Deferred DSM Costs in account 0182401 represents the (over)under collected balance of the DSM Charge that Duke Energy Kentucky collects from its customers via Rider DSM. DSM costs are recovered through the Company's DSM rider, not through the base revenue requirement. All DSM related revenues and expenses were eliminated from the test period in Schedule D-2.22.[63]

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along with my testimony.

[63] Company's response to AG 2-4(a). I have attached a copy of the response as my Exhibit___(LK-21).

It follows that any mismatch between the revenues and expenses that was deferred as a regulatory asset or liability also should be eliminated from the capitalization.

Q. What is the effect of correcting this error?

A. The effect is a reduction of $0.130 million in the base revenue requirement, assuming the Company's requested return on capitalization, but revised to reflect the gross-up at a revised gross-up at the new federal income tax rate of 21%.[64]

D. Remove East Bend Coal Ash Regulatory Asset from Capitalization

Q. Describe the Company's proposal to recover the East Bend Coal Ash ARO through the Environmental Surcharge Mechanism.

A. The Company seeks recovery of the actual incurred and forecast East Bend Coal Ash ARO costs through a new ESM rider. The Company seeks a ten-year recovery and a return on the unamortized costs incurred at the grossed-up weighted average cost of capital through the ESM rider.[65]

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[64] The calculations are detailed in my electronic workpapers filed coincident with my testimony.
[65] Company's response to Staff 2-34. I have attached a copy of the response as my Exhibit___(LK-22).

Q. Did the Company remove the East Bend Coal Ash Regulatory Asset from capitalization consistent with its request to include the costs in the proposed ESM?

A. No. This is an error in the Company's filing. The Company is entitled to one return on this regulatory asset, not two. The Company records this regulatory asset in account 182471 Coal Ash Spend – Retail (NC & MW).

Q. Does the Company now agree that the East Bend Coal Ash regulatory asset should be removed from capitalization?

A. Yes. The Company agreed that this regulatory asset should be removed from capitalization in response to AG discovery. It stated "The Company has made no adjustment to capitalization for this regulatory asset but would be willing to make an adjustment given the balance is accruing carrying costs."[66]

Q. What is the effect of correcting this error?

A. The effect is a reduction in the revenue requirement of $1.630 million, assuming the Company's requested return on capitalization, but revised to reflect the gross-up at the new federal income tax rate of 21%.[67]

IV. COST OF CAPITAL ISSUES

[66] Company's response to AG 2-4(e).
[67] The calculations are detailed in my electronic workpapers filed coincident with my testimony.

<u>A. Effect of Return on Common Equity Recommended by AG</u>

Q. Have you quantified the effect on the Company's revenue requirement of the return on equity recommendation sponsored by AG witness Mr. Richard Baudino?

A. Yes. The effect is a reduction of $6.363 million in the base revenue requirement. There is an additional effect on the ESM revenue requirement and the proposed DCI revenue requirement, although I have not quantified these effects. As I noted in the Summary section of my testimony, the AG strongly opposes the proposed DCI rider.

Q. What is the effect of each 1.0% return on common equity?

A. The effect of each 1.0% return on common equity is $4.242 million on the base revenue requirement. As I noted previously, there also is an effect on the ESM revenue requirement and the proposed DCI revenue requirement, although I have not quantified these effects.

Q. What is the pretax return on common equity requested by the Company and that recommended by the AG?

A. The pretax return on common equity requested by the Company is 16.79%, which is based on the 35% federal income tax rate reflected in the filing. This pretax return drops to 13.81% based on the 21% income tax rate. The pretax return recommended by AG is 11.80% based on the 21% income tax rate.

The pretax return is the return on common equity that must be recovered from ratepayers in the revenue requirement. It includes federal and state income taxes that must be recovered in the revenue requirement, but that are expensed by the Company in computing its earned return. For this purpose, I included not only the gross-up for income taxes on the return on common equity but also the Company's proposed gross-up for uncollectibles expense and the Commission maintenance fee.

Q. Describe why there will be an effect on the ESM revenue requirement and the DCI revenue requirement, if adopted, in addition to the effect on the base revenue requirement.

A. The Commission historically has used the return on common equity set in the utility's most recent base rate proceeding in the return applied in other riders, such as proposed the ESM. Unlike base rates, which in this proceeding will be based on a forecast test year, the ESM reflects actual costs that have been incurred. Thus, the effect of the return on common equity will change as the rate base included in the monthly ESM filings changes after the date base rates are reset in this proceeding.

V. ENVIRONMENTAL SURCHARGE MECHANISM

Q. Describe the Company's proposed recovery of the East Bend Coal Ash ARO through the ESM.

A. The Company proposes recovery of the East Bend Coal Ash ARO through a straight-line amortization over ten years (from June 2018 through May 2018).

Q. Has the Company actually incurred all the East Bend Coal Ash ARO costs?

A. No.

Q. Does KRS 278.183 limit recovery of environmental costs through the ESM to actual costs incurred?

A. Yes. KRS 278.183(2) states that costs recovered through the environmental surcharge be included on customer bills "in the second month following the month in which the costs are incurred." The Commission has the authority to determine when costs are incurred for ratemaking purposes. The company seeks authorization from the Commission to amortize and recover through the ESM costs that actually have been incurred and those that it forecasts it will incur. The latter would result in a pre-emptive amortization of costs that have not yet been incurred.

Q. Aside from the requirements of KRS 278.183(2), are there other reasons why the Commission should not allow preemptive amortization and recovery of ARO costs that have not yet been incurred?

A. Yes. Preemptive amortization and recovery of costs increases the costs to customers because it requires the prepayment of income taxes. Dismantling and site restoration costs are not deductible for income tax purposes until actually incurred. If the Commission authorizes recovery prior to the date when costs actually are incurred, this results in an increase in taxable income and current income tax expense, negative deferred income tax expense, and an asset ADIT, which is included in the ESM rate base. The grossed-up return on the asset ADIT increases the ESM revenue requirement.

Q. What is your recommendation?

A. I recommend that the Commission authorize amortization and recovery of costs in the second month after the Company actually incurs the costs related to the ARO. These costs should not be deferred as a regulatory asset and should not be included in the ESM rate base or amortization expense until after they actually are incurred. In this manner, costs to customers are minimized by avoiding the unnecessary increase in rate base from the asset ADIT.

VI. FERC TRANSMISSION COST RECONCILIATION MECHANISM

Q. Describe the Company's request for a FERC Transmission Cost Reconciliation Mechanism.

A. The Company proposes a new Rider FTR that will allow it to recover all FERC-jurisdictional transmission expenses in excess of the expense included in the base revenue requirement. The proposed "Rider FTR would track and reconcile transmission-related charges and credits such as network integration transmission service (NITS), both firm and non-firm point-to-point transmission service, transmission owner scheduling, system control and dispatch service, market administration fees, PJM's Regional Transmission Expansion Plan (RTEP) costs, and any other transmission related cost or credit that may be billed in the future by P JM that is used to supply retail load."[68]

The Company proposes a monthly/annual filing, annual review process, and an annual application for new rates, according to its Application.[69] However, Company witnesses Mr. Bruce Sailors and Mr. William Don Wathen Jr. apparently have a different proposal, i.e., quarterly filings and new rates.[70]

Q. What is your recommendation?

A. I recommend that the Commission reject the Company's proposed Rider FTR. The

[68] Direct Testimony of John D. Swez at 26-27.
[69] Application at 18-19.
[70] Direct Testimony of Bruce L. Sailors at 14 and Direct Testimony of William Don Wathen Jr. at 19.

Company's proposal will significantly and negatively transform the retail ratemaking for these costs and drive up customer rates more quickly than under the present ratemaking paradigm.

It would drive up the retail revenue requirement in real-time based on net expense (charges net of credits) pursuant to FERC tariffs. It would shift recovery from the base revenue requirement to the proposed rider. It would change recovery from a fixed amount based on the test year expense revised in conjunction with periodic base rate increases to an unending series of automatic quarterly Rider FTR rate increases based on quarterly filings. These increases likely will be significant in future years.

In addition, it would change the Company's incentives to attempt to influence these expenses or to reduce other expenses to compensate for the increases in these expenses due to the selective single nature of these expenses. Further, it would allow the Company to continually increase customer rates even if it is earning in excess of its authorized return. Finally, the Commission previously rejected a similar proposal made by Kentucky Power Company in Case No. 2014-00396. In its Order, the Commission stated:

> The Commission is in agreement with the AG on this issue. 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.[71]

Q. Does this complete your testimony?

A. Yes.

[71] Order in Case No. 2014-00396 at 33-34.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR: 1) AN ADJUSTMENT OF THE ELECTRIC RATES; (2) APPROVAL OF AN ENVIRONMENTAL ENVIRONMENTAL COMPLIANCE PLAN AND SURCHARGE MECHANISM; 3) APPROVAL OF NEW TARIFFS; 4) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES, AND (5) ALL OTHER REQUIRED APPROVALS AND RELIEF	**)**	**CASE NO. 2017-00321**

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY OFFICE OF THE ATTORNEY GENERAL

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

DECEMBER 2017

EXHIBIT ____ (LK-1)

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

Luther Rice University, MA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

Mr. Kollen has more than thirty years of utility industry experience in the financial, rate, tax, and planning areas. He specializes in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition and diversification. Mr. Kollen has expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present:

J. Kennedy and Associates, Inc.: Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Maryland, Minnesota, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, West Virginia and Wisconsin state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986:

Energy Management Associates: Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983:

The Toledo Edison Company: Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

RESUME OF LANE KOLLEN, VICE PRESIDENT

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
CF&I Steel, L.P.
Climax Molybdenum Company
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
Gallatin Steel
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for
  Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial
  Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy
  Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Cities in Texas-New Mexico Power Company's Service Territory
Cities in AEP Texas Central Company's Service Territory
Cities in AEP Texas North Company's Service Territory
Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

RESUME OF LANE KOLLEN, VICE PRESIDENT

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

Expert Testimony Appearances
of
Lane Kollen
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County, completion.

Expert Testimony Appearances
of
Lane Kollen
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric Corp.	Financial workout plan.
5/88	M-87017-1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017-2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.
7/88	M-87017-1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
7/88	M-87017-2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170-EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171-EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800-355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71).
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.

Expert Testimony Appearances
of
Lane Kollen
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.

Expert Testimony Appearances
of
Lane Kollen
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231-E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	PUC Docket 10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.

**Expert Testimony Appearances
of
Lane Kollen
As of September 2017**

Date	Case	Jurisdict.	Party	Utility	Subject
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base.
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
3/93	93-01-EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission	Gulf States Utilities /Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
4/94	U-20647 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.

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9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U Rebuttal	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co., The Cleveland Electric Illuminating Co.	Competition, asset write-offs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC Docket 14965	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.

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7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co., and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co., Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness.
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.

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11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.
11/97	U-22491	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	U-22491 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.

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10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
4/99	99-02-05	Ct	Connecticut Industrial Utility Customers	Connecticut Light and Power Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.

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5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Co.	Alternative regulation.
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, American Electric Power Co.	Merger Settlement and Stipulation.
7/99	97-596 Surrebuttal	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 Surrebuttal	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
8/99	98-474 98-083 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
8/99	98-0452-E-GI Rebuttal	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
10/99	U-24182 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	PUC Docket 21527	TX	The Dallas-Fort Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
01/00	U-24182 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
04/00	99-1212-EL-ETP 99-1213-EL-ATA 99-1214-EL-AAM	OH	Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
05/00	2000-107	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 Supplemental Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT, EDIT, ITC.
07/00	PUC Docket 22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	SOAH Docket 473-00-1015 PUC Docket 22350	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 Affidavit	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009	PA	Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925, U-22092 (Subdocket B) Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy Corp.	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.

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07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Company	Revenue requirements, Rate Plan, fuel clause recovery.
11/01	14311-U Direct Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
11/01	U-25687 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	PUC Docket 25230	TX	The Dallas-Fort Worth Hospital Council and the Coalition of Independent Colleges and Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02	U-25687 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02	14311-U Rebuttal Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	14311-U Rebuttal Panel with Michelle L. Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear life extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02	U-25687 (Suppl. Surrebuttal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 U-22092 (Subdocket C)	LA	Louisiana Public Service Commission	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.

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09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.
04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.
11/03	ER03-583-000, ER03-583-001, ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated)	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Unit power purchases and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Purchased power contracts between affiliates, terms and conditions.

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03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	SOAH Docket 473-04-2459 PUC Docket 29206	TX	Cities Served by Texas-New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including valuation issues, ITC, ADIT, excess earnings.
05/04	04-169-EL-UNC	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan, deferrals, T&D rate increases, earnings.
06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction true-up revenues, interest.
08/04	SOAH Docket 473-04-4555 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand.
09/04	U-23327 Subdocket B	LA	Louisiana Public Service Commission Staff	SWEPCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC Orders.
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission Staff	SWEPCO	Revenue requirements.
12/04	Case Nos. 2004-00321, 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, et al.	Environmental cost recovery, qualified costs, TIER requirements, cost allocation.
01/05	30485	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric, LLC	Stranded cost true-up including regulatory Central Co. assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
02/05	18638-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements.
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan.

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02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Energy conservation, economic development, and tariff issues.
03/05	Case Nos. 2004-00426, 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP system sales.
06/05	050045-EI	FL	South Florida Hospital and Heallthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.
08/05	31056	TX	Alliance for Valley Healthcare	AEP Texas Central Co.	Stranded cost true-up including regulatory assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
09/05	20298-U	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Revenue requirements, roll-in of surcharges, cost recovery through surcharge, reporting requirements.
09/05	20298-U Panel with Victoria Taylor	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization, cost of debt.
10/05	04-42	DE	Delaware Public Service Commission Staff	Artesian Water Co.	Allocation of tax net operating losses between regulated and unregulated.
11/05	2005-00351 2005-00352	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Workforce Separation Program cost recovery and shared savings through VDT surcredit.
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	System Sales Clause Rider, Environmental Cost Recovery Rider. Net Congestion Rider, Storm damage, vegetation management program, depreciation, off-system sales, maintenance normalization, pension and OPEB.
03/06	PUC Docket 31994	TX	Cities	Texas-New Mexico Power Co.	Stranded cost recovery through competition transition or change.
05/06	31994 Supplemental	TX	Cities	Texas-New Mexico Power Co.	Retrospective ADFIT, prospective ADFIT.
03/06	U-21453, U-20925, U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.

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03/06	NOPR Reg 104385-OR	IRS	Alliance for Valley Health Care and Houston Council for Health Education	AEP Texas Central Company and CenterPoint Energy Houston Electric	Proposed Regulations affecting flow- through to ratepayers of excess deferred income taxes and investment tax credits on generation plant that is sold or deregulated.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	2002-2004 Audit of Fuel Adjustment Clause Filings. Affiliate transactions.
07/06	R-00061366, Et. al.	PA	Met-Ed Ind. Users Group Pennsylvania Ind. Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of NUG-related stranded costs, government mandated program costs, storm damage costs.
07/06	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
08/06	U-21453, U-20925, U-22092 (Subdocket J)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
11/06	05CVH03-3375 Franklin County Court Affidavit	OH	Various Taxing Authorities (Non-Utility Proceeding)	State of Ohio Department of Revenue	Accounting for nuclear fuel assemblies as manufactured equipment and capitalized plant.
12/06	U-23327 Subdocket A Reply Testimony	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
03/07	PUC Docket 33309	TX	Cities	AEP Texas Central Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	PUC Docket 33310	TX	Cities	AEP Texas North Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Interim rate increase, RUS loan covenants, credit facility requirements, financial condition.
03/07	U-29157	LA	Louisiana Public Service Commission Staff	Cleco Power, LLC	Permanent (Phase II) storm damage cost recovery.
04/07	U-29764 Supplemental and Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
04/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and state income tax effects on equalization remedy receipts.
04/07	ER07-684-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuel hedging costs and compliance with FERC USOA.

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05/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and account 924 effects on MSS-3 equalization remedy payments and receipts.
06/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC, Entergy Gulf States, Inc.	Show cause for violating LPSC Order on fuel hedging costs.
07/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Revenue requirements, post-test year adjustments, TIER, surcharge revenues and costs, financial need.
07/07	ER07-956-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Storm damage costs related to Hurricanes Katrina and Rita and effects of MSS-3 equalization payments and receipts.
10/07	05-UR-103 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	05-UR-103 Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction.
11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.
11/07	ER07-682-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	ER07-682-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	07-551-EL-AIR Direct	OH	Ohio Energy Group, Inc.	Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company	Revenue requirements.
02/08	ER07-956-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.

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03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
04/08	2007-00562, 2007-00563	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas and Electric Co.	Merger surcredit.
04/08	26837 Direct Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Suppl Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
06/08	2008-00115	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Environmental surcharge recoveries, including costs recovered in existing rates, TIER.
07/08	27163 Direct	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Revenue requirements, including projected test year rate base and expenses.
07/08	27163 Taylor, Kollen Panel	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Affiliate transactions and division cost allocations, capital structure, cost of debt.
08/08	6680-CE-170 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Nelson Dewey 3 or Colombia 3 fixed financial parameters.
08/08	6680-UR-116 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	CWIP in rate base, labor expenses, pension expense, financing, capital structure, decoupling.
08/08	6680-UR-116 Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Capital structure.
08/08	6690-UR-119 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, incentive compensation, Crane Creek Wind Farm incremental revenue requirement, capital structure.
09/08	6690-UR-119 Surrebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, Section 199 deduction.

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09/08	08-935-EL-SSO, 08-918-EL-SSO	OH	Ohio Energy Group, Inc.	First Energy	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	08-917-EL-SSO	OH	Ohio Energy Group, Inc.	AEP	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	2007-00564, 2007-00565, 2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Company	Revenue forecast, affiliate costs, ELG v ASL depreciation procedures, depreciation expenses, federal and state income tax expense, capitalization, cost of debt.
11/08	EL08-51	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities, regulatory asset and bandwidth remedy.
11/08	35717	TX	Cities Served by Oncor Delivery Company	Oncor Delivery Company	Recovery of old meter costs, asset ADFIT, cash working capital, recovery of prior year restructuring costs, levelized recovery of storm damage costs, prospective storm damage accrual, consolidated tax savings adjustment.
12/08	27800	GA	Georgia Public Service Commission	Georgia Power Company	AFUDC versus CWIP in rate base, mirror CWIP, certification cost, use of short term debt and trust preferred financing, CWIP recovery, regulatory incentive.
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
01/09	ER08-1056 Supplemental Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Blytheville leased turbines; accumulated depreciation.
02/09	EL08-51 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities regulatory asset and bandwidth remedy.
02/09	2008-00409 Direct	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Revenue requirements.
03/09	ER08-1056 Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
03/09 04/09	U-21453, U-20925 U-22092 (Sub J) Direct Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	2009-00040 Direct-Interim (Oral)	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Emergency interim rate increase; cash requirements.

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04/09	PUC Docket 36530	TX	State Office of Administrative Hearings	Oncor Electric Delivery Company, LLC	Rate case expenses.
05/09	ER08-1056 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
06/09	2009-00040 Direct-Permanent	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements, TIER, cash flow.
07/09	080677-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Multiple test years, GBRA rider, forecast assumptions, revenue requirement, O&M expense, depreciation expense, Economic Stimulus Bill, capital structure.
08/09	U-21453, U-20925, U-22092 (Subdocket J) Supplemental Rebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
08/09	8516 and 29950	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Modification of PRP surcharge to include infrastructure costs.
09/09	05-UR-104 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Revenue requirements, incentive compensation, depreciation, deferral mitigation, capital structure, cost of debt.
09/09	09AL-299E	CO	CF&I Steel, Rocky Mountain Steel Mills LP, Climax Molybdenum Company	Public Service Company of Colorado	Forecasted test year, historic test year, proforma adjustments for major plant additions, tax depreciation.
09/09	6680-UR-117 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Power and Light Company	Revenue requirements, CWIP in rate base, deferral mitigation, payroll, capacity shutdowns, regulatory assets, rate of return.
10/09	09A-415E Answer	CO	Cripple Creek & Victor Gold Mining Company, et al.	Black Hills/CO Electric Utility Company	Cost prudence, cost sharing mechanism.
10/09	EL09-50 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
10/09	2009-00329	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Trimble County 2 depreciation rates.
12/09	PUE-2009-00030	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Return on equity incentive.

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12/09	ER09-1224 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	ER09-1224 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	EL09-50 Rebuttal Supplemental Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
02/10	ER09-1224 Final	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
02/10	30442 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Revenue requirement issues.
02/10	30442 McBride-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Affiliate/division transactions, cost allocation, capital structure.
02/10	2009-00353	KY	Kentucky Industrial Utility Customers, Inc., Attorney General	Louisville Gas and Electric Company, Kentucky Utilities Company	Ratemaking recovery of wind power purchased power agreements.
03/10	2009-00545	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Ratemaking recovery of wind power purchased power agreement.
03/10	E015/GR-09-1151	MN	Large Power Interveners	Minnesota Power	Revenue requirement issues, cost overruns on environmental retrofit project.
03/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation expense and effects on System Agreement tariffs.
04/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Revenue requirement issues.
04/10	2009-00548, 2009-00549	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	Revenue requirement issues.
08/10	31647	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Revenue requirement and synergy savings issues.
08/10	31647 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Affiliate transaction and Customer First program issues.

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08/10	2010-00204	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	PPL acquisition of E.ON U.S. (LG&E and KU) conditions, acquisition savings, sharing deferral mechanism.
09/10	38339 Direct and Cross-Rebuttal	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Revenue requirement issues, including consolidated tax savings adjustment, incentive compensation FIN 48; AMS surcharge including roll-in to base rates; rate case expenses.
09/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.
09/10	2010-00167	KY	Gallatin Steel	East Kentucky Power Cooperative, Inc.	Revenue requirements.
09/10	U-23327 Subdocket E Direct	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
11/10	U-23327 Rebuttal	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
09/10	U-31351	LA	Louisiana Public Service Commission Staff	SWEPCO and Valley Electric Membership Cooperative	Sale of Valley assets to SWEPCO and dissolution of Valley.
10/10	10-1261-EL-UNC	OH	Ohio OCC, Ohio Manufacturers Association, Ohio Energy Group, Ohio Hospital Association, Appalachian Peace and Justice Network	Columbus Southern Power Company	Significantly excessive earnings test.
10/10	10-0713-E-PC	WV	West Virginia Energy Users Group	Monongahela Power Company, Potomac Edison Power Company	Merger of First Energy and Allegheny Energy.
10/10	U-23327 Subdocket F Direct	LA	Louisiana Public Service Commission Staff	SWEPCO	AFUDC adjustments in Formula Rate Plan.
11/10	EL10-55 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.
12/10	ER10-1350 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
01/11	ER10-1350 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.

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03/11 04/11	ER10-2001 Direct Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Arkansas, Inc.	EAI depreciation rates.
04/11	U-23327 Subdocket E	LA	Louisiana Public Service Commission Staff	SWEPCO	Settlement, incl resolution of S02 allowance expense, var O&M expense, sharing of OSS margins.
04/11 05/11	38306 Direct Suppl Direct	TX	Cities Served by Texas-New Mexico Power Company	Texas-New Mexico Power Company	AMS deployment plan, AMS Surcharge, rate case expenses.
05/11	11-0274-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company, Wheeling Power Company	Deferral recovery phase-in, construction surcharge.
05/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements.
06/11	29849	GA	Georgia Public Service Commission Staff	Georgia Power Company	Accounting issues related to Vogtle risk-sharing mechanism.
07/11	ER11-2161 Direct and Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
07/11	PUE-2011-00027	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Return on equity performance incentive.
07/11	11-346-EL-SSO 11-348-EL-SSO 11-349-EL-AAM 11-350-EL-AAM	OH	Ohio Energy Group	AEP-OH	Equity Stabilization Incentive Plan; actual earned returns; ADIT offsets in riders.
08/11	U-23327 Subdocket F Rebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Depreciation rates and service lives; AFUDC adjustments.
08/11	05-UR-105	WI	Wisconsin Industrial Energy Group	WE Energies, Inc.	Suspended amortization expenses; revenue requirements.
08/11	ER11-2161 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
09/11	PUC Docket 39504	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Investment tax credit, excess deferred income taxes; normalization.
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility Consumers, Inc.	Louisville Gas & Electric Company, Kentucky Utilities Company	Environmental requirements and financing.
10/11	11-4571-EL-UNC 11-4572-EL-UNC	OH	Ohio Energy Group	Columbus Southern Power Company, Ohio Power Company	Significantly excessive earnings.

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10/11	4220-UR-117 Direct	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	4220-UR-117 Surrebuttal	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	PUC Docket 39722	TX	Cities Served by AEP Texas Central Company	AEP Texas Central Company	Investment tax credit, excess deferred income taxes; normalization.
02/12	PUC Docket 40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Temporary rates.
03/12	11AL-947E Answer	CO	Climax Molybdenum Company and CF&I Steel, L.P. d/b/a Evraz Rocky Mountain Steel	Public Service Company of Colorado	Revenue requirements, including historic test year, future test year, CACJA CWIP, contra-AFUDC.
03/12	2011-00401	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Big Sandy 2 environmental retrofits and environmental surcharge recovery.
4/12	2011-00036 Direct Rehearing Supplemental Direct Rehearing	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Rate case expenses, depreciation rates and expense.
04/12	10-2929-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, CRES capacity charges, Equity Stabilization Mechanism
05/12	11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, Equity Stabilization Mechanism, Retail Stability Rider.
05/12	11-4393-EL-RDR	OH	Ohio Energy Group	Duke Energy Ohio, Inc.	Incentives for over-compliance on EE/PDR mandates.
06/12	40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Revenue requirements, including ADIT, bonus depreciation and NOL, working capital, self insurance, depreciation rates, federal income tax expense.
07/12	120015-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Revenue requirements, including vegetation management, nuclear outage expense, cash working capital, CWIP in rate base.
07/12	2012-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental retrofits, including environmental surcharge recovery.
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Company	Section 1603 grants, new solar facility, payroll expenses, cost of debt.
10/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Revenue requirements, including off-system sales, outage maintenance, storm damage, injuries and damages, depreciation rates and expense.

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10/12	120015-EI Direct	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
11/12	120015-EI Rebuttal	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
10/12	40604	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Policy and procedural issues, revenue requirements, including AFUDC, ADIT – bonus depreciation & NOL, incentive compensation, staffing, self-insurance, net salvage, depreciation rates and expense, income tax expense.
11/12	40627 Direct	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
12/12	40443	TX	Cities Served by SWEPCO	Southwestern Electric Power Company	Revenue requirements, including depreciation rates and service lives, O&M expenses, consolidated tax savings, CWIP in rate base, Turk plant costs.
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Termination of purchased power contracts between EGSL and ETI, Spindletop regulatory asset.
01/13	ER12-1384 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Little Gypsy 3 cancellation costs.
02/13	40627 Rebuttal	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
03/13	12-426-EL-SSO	OH	The Ohio Energy Group	The Dayton Power and Light Company	Capacity charges under state compensation mechanism, Service Stability Rider, Switching Tracker.
04/13	12-2400-EL-UNC	OH	The Ohio Energy Group	Duke Energy Ohio, Inc.	Capacity charges under state compensation mechanism, deferrals, rider to recover deferrals.
04/13	2012-00578	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Resource plan, including acquisition of interest in Mitchell plant.
05/13	2012-00535	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
06/13	12-3254-EL-UNC	OH	The Ohio Energy Group, Inc., Office of the Ohio Consumers' Counsel	Ohio Power Company	Energy auctions under CBP, including reserve prices.
07/13	2013-00144	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Biomass renewable energy purchase agreement.

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07/13	2013-00221	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Hawesville Smelter market access.
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
12/13	2013-00413	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Sebree Smelter market access.
01/14	ER10-1350	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 lease accounting and treatment in annual bandwidth filings.
02/14	U-32981	LA	Louisiana Public Service Commission	Entergy Louisiana, LLC	Montauk renewable energy PPA.
04/14	ER13-432 Direct	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
05/14	PUE-2013-00132	VA	HP Hood LLC	Shenandoah Valley Electric Cooperative	Market based rate; load control tariffs.
07/14	PUE-2014-00033	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting, change in FAC Definitional Framework.
08/14	ER13-432 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
08/14	2014-00134	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Requirements power sales agreements with Nebraska entities.
09/14	E-015/CN-12-1163 Direct	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class cost allocation.
10/14	2014-00225	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Allocation of fuel costs to off-system sales.
10/14	ER13-1508	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy service agreements and tariffs for affiliate power purchases and sales; return on equity.
10/14	14-0702-E-42T 14-0701-E-D	WV	West Virginia Energy Users Group	First Energy-Monongahela Power, Potomac Edison	Consolidated tax savings; payroll; pension, OPEB, amortization; depreciation; environmental surcharge.
11/14	E-015/CN-12-1163 Surrebuttal	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class allocation.
11/14	05-376-EL-UNC	OH	Ohio Energy Group	Ohio Power Company	Refund of IGCC CWIP financing cost recoveries.

**Expert Testimony Appearances
of
Lane Kollen
As of September 2017**

Date	Case	Jurisdict.	Party	Utility	Subject
11/14	14AL-0660E	CO	Climax, CF&I Steel	Public Service Company of Colorado	Historic test year v. future test year; AFUDC v. current return; CACJA rider, transmission rider; equivalent availability rider; ADIT; depreciation; royalty income; amortization.
12/14	EL14-026	SD	Black Hills Industrial Intervenors	Black Hills Power Company	Revenue requirement issues, including depreciation expense and affiliate charges.
12/14	14-1152-E-42T	WV	West Virginia Energy Users Group	AEP-Appalachian Power Company	Income taxes, payroll, pension, OPEB, deferred costs and write offs, depreciation rates, environmental projects surcharge.
01/15	9400-YO-100 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Energy Corporation	WEC acquisition of Integrys Energy Group, Inc.
01/15	14F-0336EG 14F-0404EG	CO	Development Recovery Company LLC	Public Service Company of Colorado	Line extension policies and refunds.
02/15	9400-YO-100 Rebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Energy Corporation	WEC acquisition of Integrys Energy Group, Inc.
03/15	2014-00396	KY	Kentucky Industrial Utility Customers, Inc.	AEP-Kentucky Power Company	Base, Big Sandy 2 retirement rider, environmental surcharge, and Big Sandy 1 operation rider revenue requirements, depreciation rates, financing, deferrals.
03/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company and Louisville Gas and Electric Company	Revenue requirements, staffing and payroll, depreciation rates.
04/15	2014-00450	KY	Kentucky Industrial Utility Customers, Inc. and the Attorney General of the Commonwealth of Kentucky	AEP-Kentucky Power Company	Allocation of fuel costs between native load and off-system sales.
04/15	2014-00455	KY	Kentucky Industrial Utility Customers, Inc. and the Attorney General of the Commonwealth of Kentucky	Big Rivers Electric Corporation	Allocation of fuel costs between native load and off-system sales.
04/15	ER2014-0370	MO	Midwest Energy Consumers' Group	Kansas City Power & Light Company	Affiliate transactions, operation and maintenance expense, management audit.
05/15	PUE-2015-00022	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting; change in FAC Definitional Framework.
05/15 09/15	EL10-65 Direct, Rebuttal Complaint	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Accounting for AFUDC Debt, related ADIT.

Expert Testimony Appearances
of
Lane Kollen
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
07/15	EL10-65 Direct and Answering Consolidated Bandwidth Dockets	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback ADIT, Bandwidth Formula.
09/15	14-1693-EL-RDR	OH	Public Utilities Commission of Ohio	Ohio Energy Group	PPA rider for charges or credits for physical hedges against market.
12/15	45188	TX	Cities Served by Oncor Electric Delivery Company	Oncor Electric Delivery Company	Hunt family acquisition of Oncor; transaction structure; income tax savings from real estate investment trust (REIT) structure; conditions.
12/15 01/16	6680-CE-176 Direct, Surrebuttal, Supplemental Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Need for capacity and economics of proposed Riverside Energy Center Expansion project; ratemaking conditions.
03/16 0/16 04/16 05/16 06/16	EL01-88 Remand Direct Answering Cross-Answering Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Bandwidth Formula: Capital structure, fuel inventory, Waterford 3 sale/leaseback, Vidalia purchased power, ADIT, Blythesville, Spindletop, River Bend AFUDC, property insurance reserve, nuclear depreciation expense.
03/16	15-1673-E-T	WV	West Virginia Energy Users Group	Appalachian Power Company	Terms and conditions of utility service for commercial and industrial customers, including security deposits.
04/16	39971 Panel Direct	GA	Georgia Public Service Commission Staff	Southern Company, AGL Resources, Georgia Power Company, Atlanta Gas Light Company	Southern Company acquisition of AGL Resources, risks, opportunities, quantification of savings, ratemaking implications, conditions, settlement.
04/16	2015-00343	KY	Office of the Attorney General	Atmos Energy Corporation	Revenue requirements, including NOL ADIT, affiliate transactions.
04/16	2016-00070	KY	Office of the Attorney General	Atmos Energy Corporation	R & D Rider.
05/16	2016-00026 2016-00027	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Need for environmental projects, calculation of environmental surcharge rider.
05/16	16-G-0058 16-G-0059	NY	New York City	Keyspan Gas East Corp., Brooklyn Union Gas Company	Depreciation, including excess reserves, leak prone pipe.
06/16	160088-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Fuel Adjustment Clause Incentive Mechanism re: economy sales and purchases, asset optimization.

Expert Testimony Appearances
of
Lane Kollen
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
07/16	160021-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Revenue requirements, including capital recovery, depreciation, ADIT.
08/16	15-1022-EL-UNC 16-1105-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power Company	SEET earnings, effects of other pending proceedings.
9/16	2016-00162	KY	Office of the Attorney General	Columbia Gas Kentucky	Revenue requirements, O&M expense, depreciation, affiliate transactions.
09/16	E-22 Sub 519, 532, 533	NC	Nucor Steel	Dominion North Carolina Power Company	Revenue requirements, deferrals and amortizations.
09/16	15-1256-G-390P (Reopened) 16-0922-G-390P	WV	West Virginia Energy Users Group	Mountaineer Gas Company	Infrastructure rider, including NOL ADIT and other income tax normalization and calculation issues.
10/16	10-2929-EL-UNC 11-346-EL-SSO 11-348-EL-SSO 11-349-EL-SSO 11-350-EL-SSO 14-1186-EL-RDR	OH	Ohio Energy Group	AEP Ohio Power Company	State compensation mechanism, capacity cost, Retail Stability Rider deferrals, refunds, SEET.
11/16	16-0395-EL-SSO Direct	OH	Ohio Energy Group	Dayton Power & Light Company	Credit support and other riders; financial stability of Utility, holding company.
12/16	Formal Case 1139	DC	Healthcare Council of the National Capital Area	Potomac Electric Power Company	Post test year adjust, merger costs, NOL ADIT, incentive compensation, rent.
01/17	46238	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Company	Acquisition of Oncor by Next Era Energy; goodwill, transaction costs, transition costs, cost deferrals, ratemaking issues.
02/17	16-0395-EL-SSO Direct (Stipulation)	OH	Ohio Energy Group	Dayton Power & Light Company	Non-unanimous stipulation re: credit support and other riders; financial stability of utility, holding company.
02/17	45414	TX	Cities of Midland, McAllen, and Colorado City	Sharyland Utilities, LP, Sharyland Distribution & Transmission Services, LLC	Income taxes, depreciation, deferred costs, affiliate expenses.
03/17	2016-00370 2016-00371	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	AMS, capital expenditures, maintenance expense, amortization expense, depreciation rates and expense.
06/17	29849 (Panel with Philip Hayet)	GA	Georgia Public Service Commission Staff	Georgia Power Company	Vogtle 3 and 4 economics.

Expert Testimony Appearances
of
Lane Kollen
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
08/17	17-0296-E-PC	WV	Public Service Commission of West Virginia Charleston	Monongahela Power Company, The Potomac Edison Power Company	ADIT, OPEB.

EXHIBIT ____ (LK-2)

AG-DR-02-011

REQUEST:

Refer to the "BP Rev by Product" and the "FP Rev by Product" worksheet tabs in the Excel filing schedules provided in response to Staff 1-71.

a. Explain why the Company shows no revenues in the base period forecast months and no revenues in the forecast period months for account 456025 even though there were actual revenues in every month of the base period actual months.

b. Provide the actual revenues recorded in account 456025 for each month January 2012 through the most recent month for which actual amounts are available.

c. Explain why the Company shows no revenue in the base period forecast months and no revenues in the forecast period months for account 453625 even though there were actual revenue in the first four base period actual months.

d. Provide the actual revenues recorded in account 453625 for each month January 2012 through the most recent month for which actual amounts are available.

e. Explain why the Company shows no revenues in the base period forecast months and no revenues in the forecast period months for account 457105 even though there were actual revenues in several of the base period actual months.

f. Provide the actual revenues recorded in account 457105 for each month January 2012 through the most recent month for which actual amounts are available.

g. Explain why the Company shows no revenues in the base period forecast months and no revenues in the forecast period months for account 457204 even though there were actual revenues in every month of the base period actual months.

h. Provide the actual revenues recorded in account 457204 for each month January 2012 through the most recent month for which actual amounts are available.

RESPONSE:

a. The actual amounts recorded in Account 456025 are related to PJM billing line items 2370, Day-ahead Operating Reserve Credit, and 2375, Balancing Operating Reserve. These billing line items are to ensure that generation owners are fully compensated by PJM for their daily offer amounts. For budgeting purposes the Company assumes that the day-ahead and real-time offers are the same.

b. See AG-DR-02-011 Attachment being uploaded electronically and a copy provided on CD.

c. The company does not budget all individual miscellaneous revenue accounts but instead attempts to ensure that miscellaneous revenues trend properly in total.

d. See AG-DR-02-011 Attachment being uploaded electronically and a copy provided on CD.

e. The company does not budget all individual miscellaneous revenue accounts but instead attempts to ensure that miscellaneous revenues trend properly in total.

f. See AG-DR-02-011 Attachment being uploaded electronically and a copy provided on CD.

g. There were no amounts in the forecasted months of the base period due to an oversight during the 2017 budgeting process. The forecasted period did contain budgeted amounts for Account 457204.

h. See AG-DR-02-011 Attachment being uploaded electronically and a copy provided on CD.

PERSON RESPONSIBLE: David L. Doss / Beau Pratt

Duke Energy Kentucky
Miscellaneous Revenue Accounts

Account ID CB	Account Long Descr CB	Accounting Period CMD	2012	2013	2014	2015	2016	2017
453625	Intercompany Sales of Water	1						(9,819.25)
	Intercompany Sales of Water	2						(9,819.25)
	Intercompany Sales of Water	3						(9,819.25)
	Intercompany Sales of Water	12					(85,000.00)	
453625		Sum:					(85,000.00)	(29,457.75)
456025	RSG Rev - MISO Make Whole	1	(6,153.96)	0.00	(1,042,739.35)	(9,885.47)	(101,865.16)	(172,028.35)
	RSG Rev - MISO Make Whole	2	(14.50)	4.92	(220,230.93)	(555,317.32)	(76,528.62)	(20,831.36)
	RSG Rev - MISO Make Whole	3	0.00	(48,698.48)	(142,571.13)	(290,636.34)	(37,198.09)	(222,875.39)
	RSG Rev - MISO Make Whole	4	0.00	(34,901.41)	(24,282.88)	(23.42)	(63,736.73)	(20.07)
	RSG Rev - MISO Make Whole	5	0.00	0.00	(1,663.80)	(79,566.07)	18.72	(52,195.30)
	RSG Rev - MISO Make Whole	6	(46,338.98)	(34,505.45)	(55,186.32)	(120,611.57)	(18,817.21)	92.48
	RSG Rev - MISO Make Whole	7	(1,329,988.50)	(342,204.05)	(59,569.10)	(72,073.33)	(280,421.41)	(79,845.12)
	RSG Rev - MISO Make Whole	8	(5,690.05)	(6,660.93)	(1.93)	(115,579.59)	(285,681.32)	(136,878.11)
	RSG Rev - MISO Make Whole	9	(352,985.31)	(185,054.06)	53.29	(99,891.46)	(125,180.72)	(48,994.13)
	RSG Rev - MISO Make Whole	10	0.00	(5.49)	(15,595.12)	182,660.25	(250,140.13)	(117,420.01)
	RSG Rev - MISO Make Whole	11	(52,657.58)	(12,930.81)	(27,582.09)	(153,731.63)	(217,217.97)	
	RSG Rev - MISO Make Whole	12	(21,513.36)	(122,544.15)	(11.32)	(74,092.20)	(66,722.12)	
456025		Sum:	(1,815,342.24)	(787,499.91)	(1,589,380.68)	(1,388,748.15)	(1,523,490.76)	(850,995.36)
457105	Scheduling & Dispatch Revenues	1						
	Scheduling & Dispatch Revenues	2						(65,633.96)
	Scheduling & Dispatch Revenues	3						(13,301.99)
	Scheduling & Dispatch Revenues	4						0.80
	Scheduling & Dispatch Revenues	5						(15,074.62)
	Scheduling & Dispatch Revenues	6						(20,538.62)
	Scheduling & Dispatch Revenues	7						(29,182.04)
	Scheduling & Dispatch Revenues	8						(30,090.63)
	Scheduling & Dispatch Revenues	9						(17,235.94)
	Scheduling & Dispatch Revenues	10						(16,183.17)
	Scheduling & Dispatch Revenues	11						
	Scheduling & Dispatch Revenues	12						
457105		Sum:						(207,240.17)
457204	PJM Reactive Rev	1						(24,056.86)
	PJM Reactive Rev	2						45,056.86
	PJM Reactive Rev	3						(622,802.31)
	PJM Reactive Rev	4						(177,769.09)
	PJM Reactive Rev	5						(156,769.06)
	PJM Reactive Rev	6						(156,769.19)
	PJM Reactive Rev	7						(156,769.12)
	PJM Reactive Rev	8						(156,769.10)
	PJM Reactive Rev	9						(156,769.14)
	PJM Reactive Rev	10						(156,769.18)
	PJM Reactive Rev	11						
	PJM Reactive Rev	12					(1,100,470.38)	
457204		Sum:	0.00	0.00	0.00	0.00	(1,100,470.38)	(1,720,186.19)
		Sum:	(1,815,342.24)	(787,499.91)	(1,589,380.68)	(1,388,748.15)	(2,708,961.14)	(2,807,879.47)

EXHIBIT ____ (LK-3)

AG-DR-02-021

REQUEST:

Refer to the proposed Rider PSM. Provide all calculation components for the test year under the proposed rider, assuming it is adopted with no modifications. Provide all support for your calculations, including electronic spreadsheets in live format with all formulas intact and all support documents or other support for assumptions and/or other input amounts.

RESPONSE:

Please see AG-DR-02-021 Attachment being uploaded electronically and a copy provided on CD.

PERSON RESPONSIBLE: William Don Wathen Jr.

DUKE ENERGY KENTUCKY, Inc.

Proposed Rider PSM for the Forecasted Test Period

Line No.	Description		Source		Total
1	**Off-System Sales Revenue**				
2	Asset Energy	(+)	WPD-2.20a		$ 11,959,000
3	Non-Asset Energy	(+)			-
4	Bilateral Sales	(+)			-
5	Hedges	(+)			-
6	PJM Bal & DA Oper Reserve Credits	(+)			-
7	***Fuel Related RTO Costs and Credits***	(+)			-
8	***Non-Fuel Related RTO Costs and Credits***	(+)			-
9	Capacity	(+)			-
10	Ancillary Services Market	(+)	WPD-2.20a	(1)	819,230
11	Sub-Total Revenues				$ 12,778,230
12					
13	**Variable Costs Allocable to Off-System Sales**				
14	Bilateral Purchases	(+)			$ -
15	Non-Native Fuel Cost	(+)	WPD-2.20a		8,758,000
16	Variable O&M Cost	(+)			-
17	SO_2 Cost	(+)	WPD-2.20a		241
18	NO_x Cost	(+)			-
19	PJM and Other Costs	(+)			-
20	(Gain)/Losss on Sale of Fuel	(+)			-
21	Sub-Total Expenses				$ 8,758,241
22	Total Off-System Sales Margin (Line 11 - Line 21)	(+)			$ 4,019,989
23	Net Margins on Capacity Transactions Allocated to Customers	(+)	WPD-2.20a		$ (204,693)
24	Net Margins on Sales of Emission Allowances	(+)			$ -
25	***Net Proceeds from the Sale of Renewable Energy Credits***	(+)			-
26	Total				$ 3,815,296
27	***Percentage Allocated to Customers (90%)***				90.00%
28	Total PSM Credit				$ 3,433,766

(1) Net of reactive power revenue and expense.

EXHIBIT ____ (LK-4)

REQUEST:

Refer to the Direct Testimony of Mr. Doss at page 5 lines 9-19 regarding the replacement power costs forecasted in the test year.

a. Provide a schedule showing the actual amounts of replacement power cost for each of the years 2013-2016 and for 2017 to date separately for the East Bend and Woodsdale units along with the same for the projected test year. In addition, please describe what considerations would need to be made when reviewing historical replacement power costs associated with the ownership change percentages of the East Bend Station occurring in 2015.

b. Explain how the projected replacement power costs from the GenTrader production cost model were determined and describe any known assumption changes from the levels experienced during the last four actual years.

c. Provide copies of all input and output sources from GenTrader used to source the test year forecasted costs.

RESPONSE:

<u>CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment (c) Only)</u>

a. See attachment AG-DR-01-011(a) Attachment for replacement power costs in 2013-2016 and 2017 to date.

b. The monthly projected cost of replacement power is calculated starting with the generation output forecast from the GenTrader model. This output is then used to calculate the monthly amount of forced generation (either from a derate or outage) by dividing by one minus the units projected forced outage rate. Next, the projected monthly weighted average cost of fuel inventory (WACI) is subtracted from the monthly forward market power price to calculate the forecasted monthly replacement power cost ($/MWhr). Finally, the replacement power cost ($/MWhr) is multiplied by the amount of forced generation (MWhrs) to calculate the forecasted monthly replacement power costs ($). It should be noted that since East Bend has a far larger share of the energy generated to serve the Duke Energy Kentucky customer, for simplicity only the generation forecast, WACI, and forced outage rate of East Bend is used in these calculations. The GenTrader model is regularly updated for various input assumptions, including commodity prices, market power forecasts, outage schedules, and forced outage rates. In addition, the Company's acquisition of the remaining share of East Bend (186 MW) as well as the retirement of Miami Fort 6 (163 MW) are known assumption changes that have occurred within the past four years.

c. Objection. The question is overbroad and unduly burdensome in sofar as the question requests all inputs and outputs sources to be provided. It would be nearly impossible to list each and every input and output that is or can be incorporated into the model. Without waiving said objection and to the extent discoverable, the major inputs and outputs of the GenTrader model are summarized in CONFIDENTIAL AG-DR-01-011(c) Attachment 1 – Inputs and CONFIDENTIAL AG-DR-01-011(c) Attachment 2 – Output provided electronically on CD.

a. Attachment AG-DR-01-011c (1) – Inputs:

    i. Load = Hourly forecast of DEK customer load, MW
    ii. Coal Prices = Coal prices delivered to East Bend Station, \$/MMBtu
    iii. Gas Prices = Gas price at Henry Hub and delivered to Woodsdale Station, \$/MMBtu
    iv. Power Prices = Power price at AD Hub and DEK Load Zone, \$/MWhr
    v. Basis = Difference between LMP at East Bend/Woodsdale Stations and AD Hub, \$/MWhr
    vi. Outage Schedule = Planned generator outage schedule
    vii. Hours = Defination of peak and off-peak times

b. Attachment AG-DR-01-011c (2)– Outputs:

    i. GenerationPivot = Monthly generation for each unit, GWHrs
    ii. GenerationRawData = Detailed monthly output, including unit generation, fuel burn, unit emissions, and reagents
    iii. NetC&L = Net congestion and losses for generation and load
    iv. GenerationC&L = Generation congestion and losses
    v. LoadC&L = Load congestion and losses

PERSON RESPONSIBLE: David L. Doss, Jr. (a)
John D. Swez/ David L. Doss, Jr. (b)
John D. Swez/ David L. Doss, Jr. (c)

Duke Energy Kentucky

Cost removed from FAC recovery due to unplanned derates and outages

Risk period (not accounting period)	East Bend	Miami Fort 6	Woodsdale	Total
Jan-13	$ 310,948	$ 231	$ -	$ 311,179
Feb-13	$ 102,282	$ 192,535	$ -	$ 294,817
Mar-13	$ 332,719	$ 2,770	$ -	$ 335,489
Apr-13	$ 192,949	$ 124,624	$ -	$ 317,573
May-13	$ 46,379	$ 330,839	$ -	$ 377,218
Jun-13	$ 50,836	$ 546,845	$ -	$ 597,681
Jul-13	$ 271,828	$ 244,982	$ -	$ 516,810
Aug-13	$ 24,663	$ 112,882	$ -	$ 137,545
Sep-13	$ 58,813	$ 16,645	$ -	$ 75,458
Oct-13	$ -	$ 136,571	$ -	$ 136,571
Nov-13	$ 169,896	$ 209,959	$ -	$ 379,855
Dec-13	$ 529,687	$ -	$ -	$ 529,687
	$ 2,090,999	$ 1,918,882	$ -	$ 4,009,881
Jan-14	$ 4,618,441	$ 1,553,519	$ -	$ 6,171,960
Feb-14	$ 2,034,815	$ 7	$ -	$ 2,034,822
Mar-14	$ 341,437	$ 1,732,470	$ -	$ 2,073,907
Apr-14	$ -	$ 11	$ -	$ 11
May-14	$ -	$ 1,366,035	$ -	$ 1,366,035
Jun-14	$ 1,108,337	$ 370,167	$ -	$ 1,478,504
Jul-14	$ 97,549	$ 298,844	$ -	$ 396,393
Aug-14	$ 3,471	$ 75,324	$ -	$ 78,795
Sep-14	$ 887,716	$ 71,401	$ -	$ 959,117
Oct-14	$ 10,390	$ 67,406	$ -	$ 77,796
Nov-14	$ -	$ 2	$ -	$ 2
Dec-14	$ 44,926	$ 2,319	$ -	$ 47,244
	$ 9,147,082	$ 5,537,505	$ -	$ 14,684,588
Jan-15	$ 16,397	$ -	$ -	$ 16,397
Feb-15	$ 195,600	$ 280,718	$ -	$ 476,318
Mar-15	$ 15,123	$ 422,558	$ -	$ 437,680
Apr-15	$ 168,672	$ -	$ -	$ 168,672
May-15	$ 77,814	$ -	$ -	$ 77,814
Jun-15	$ 598,486	$ -	$ -	$ 598,486
Jul-15	$ 79,162	$ -	$ -	$ 79,162
Aug-15	$ 72,235	$ -	$ -	$ 72,235
Sep-15	$ 28,493	$ -	$ -	$ 28,493
Oct-15	$ 2,414	$ -	$ -	$ 2,414
Nov-15	$ 36,184	$ -	$ -	$ 36,184
Dec-15	$ 3,881	$ -	$ -	$ 3,881
	$ 1,294,461	$ 703,276	$ -	$ 1,997,737
Jan-16	$ 42,306	$ -	$ -	$ 42,306
Feb-16	$ -	$ -	$ -	$ -
Mar-16	$ -	$ -	$ -	$ -
Apr-16	$ -	$ -	$ -	$ -

May-16	$	-	$	-	$	-	$	-
Jun-16	$	138,775	$	-	$	-	$	138,775
Jul-16	$	58,859	$	-	$	-	$	58,859
Aug-16	$	54,143	$	-	$	-	$	54,143
Sep-16	$	2,486	$	-	$	-	$	2,486
Oct-16	$	-	$	-	$	-	$	-
Nov-16	$	-	$	-	$	-	$	-
Dec-16		$1,451,118.28	$	-	$	-	$	1,451,118
	$	1,747,687	$	-	$	-	$	1,747,687

Jan-17	$	-	$	-	$	-	$	-
Feb-17	$	10,956	$	-	$	-	$	10,956
Mar-17	$	-	$	-	$	-	$	-
Apr-17	$	1,360	$	-	$	-	$	1,360
May-17	$	-	$	-	$	-	$	-
Jun-17	$	88,718	$	-	$	-	$	88,718
Jul-17	$	784,908	$	-	$	-	$	784,908
Aug-17	$	6,889	$	-	$	-	$	6,889
Sep-17	$	549,670	$	-	$	-	$	549,670
Oct-17			$	-	$	-	$	-
Nov-17			$	-	$	-	$	-
Dec-17			$	-	$	-	$	-
	$	1,442,500	$	-	$	-	$	1,442,500

EXHIBIT ____ (LK-5)

AG-DR-01-014

REQUEST:

Refer to the Direct Testimony of Mr. Pratt at page 21 lines 9-14 and proforma adjustment D-2.34. Provide copies of the source documents for the projected RTEP costs and provide a five year history of such costs from 2012-2016 and 2017 to date. If the projected RTEP costs are higher than the historical annual amounts, provide and quantify all reasons why this is the case.

RESPONSE:

a. See AG-DR-01-014 Attachment 1 for the calculation of the Duke Energy Kentucky RTEP expense of $4,030,393. The 2016 actual of $20,055,522 consists of (1) actual RTEP charges per PJM monthly invoices (2) estimates of current month RTEP charges and (3) reversals of previous month estimates. See AG-DR-01-014 Attachment 2 for support for the 2016 actual charges, consisting of $16,636,789 charged to Account 561800 and $3,418,733 charged to Account 566100. The 2017 Forecast of $21,598,751 is from Transmission Enhancement Worksheets that can be found on the PJM Interconnection website. The 2018 and 2019 numbers are escalated based on the ratio of 2017 to 2016.

b. See AG-DR-01-014 Attachment 3 for historical RTEP charges from January 2013 through September 2017. Duke Energy Kentucky did not incur RTEP charges in 2012.

c. The projected RTEP costs are higher than historical annual amounts because as more RTEP projects are placed into service, RTEP expense increases.

PERSON RESPONSIBLE: Robert H. Pratt

Duke Energy Kentucky, Inc.
RTEP Expense

			2016 Actuals	2017 Forecast (1)	2018 Forecast	2019 Forecast	April 1 2018 - Mar 1 2019 Forecast
2016 8x4 RTEP Forecast							
		Total Share of Projects	$ 20,055,522	$ 21,598,751	$ 23,260,729	$ 25,050,592	$ 23,708,195
RTEP	Total DEO	DEO (83%)	$ 16,646,083	$ 17,926,963	$ 19,306,405	$ 20,791,991	
RTEP	Total DEK	DEK (17%)	$ 3,409,439	$ 3,671,788	$ 3,954,324	$ 4,258,601	$ 4,030,393
		Total Duke Expense	**$ 20,055,522**	**$ 21,598,751**	**$ 23,260,729**	**$ 25,050,592**	

(1) per transmission-enhancement-worksheet-July-2017.xls

DUKE ENERGY.

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GENERAL LEDGER REPORT - DETAIL
Business Unit(s):

Fiscal Year
Currency Code: USD

Account Tree: WTB_GAAP_REPORT
Account(s):

0561800 - Reliability-Plan&Stds Dev

Fiscal Year and Period JD	Journal ID	Journal Descr JD	Bus Unit and Long Descr JD	Resp Center ID CB	Oper Unit ID CB	Res Type	Product ID CB	Invoice ID JD	Period Activity
201601	402ED301P	Estimate and reversal of estim	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			$0.00
	402ED311P	To record prior month final re	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			$1,424,962.41
201601									$1,424,962.41

Fiscal Year and Period JD	Journal ID	Journal Descr JD	Bus Unit and Long Descr JD	Resp Center ID CB	Oper Unit ID CB	Res Type	Product ID CB	Invoice ID JD	Period Activity
201602	402ED301P	Estimate and reversal of estim	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			($51,000.00)
	402ED311P	To record prior month final re	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			$1,374,233.49
201602									$1,323,233.49

Fiscal Year and Period JD	Journal ID	Journal Descr JD	Bus Unit and Long Descr JD	Resp Center ID CB	Oper Unit ID CB	Res Type	Product ID CB	Invoice ID JD	Period Activity
201603	402ED301P	Estimate and reversal of estim	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			$0.00
	402ED311P	To record prior month final re	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			$1,374,233.68
201603									$1,374,233.68

Fiscal Year and Period JD	Journal ID	Journal Descr JD	Bus Unit and Long Descr JD	Resp Center ID CB	Oper Unit ID CB	Res Type	Product ID CB	Invoice ID JD	Period Activity
201604	402ED301P	Estimate and reversal of estim	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			$0.00
	402ED311P	To record prior month final re	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			$1,373,994.37
201604									$1,373,994.37

Fiscal Year and Period JD	Journal ID	Journal Descr JD	Bus Unit and Long Descr JD	Resp Center ID CB	Oper Unit ID CB	Res Type	Product ID CB	Invoice ID JD	Period Activity
201605	402ED301P	Estimate and reversal of estim	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			$4,000.00
	402ED311P	To record prior month final re	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			$1,378,450.50
201605									$1,382,450.50

Fiscal Year and Period JD	Journal ID	Journal Descr JD	Bus Unit and Long Descr JD	Resp Center ID CB	Oper Unit ID CB	Res Type	Product ID CB	Invoice ID JD	Period Activity
201606	402ED301P	Estimate and reversal of estim	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			$31,000.00
	402ED311P	To record prior month final re	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			$1,409,121.43
201606									$1,440,121.43

Fiscal Year and Period JD	Journal ID	Journal Descr JD	Bus Unit and Long Descr JD	Resp Center ID CB	Oper Unit ID CB	Res Type	Product ID CB	Invoice ID JD	Period Activity
201607	402ED301P	Estimate and reversal of estim	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			($85,000.00)
	402ED311P	To record prior month final re	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			$1,324,469.25
201607									$1,239,469.25

Fiscal Year and Period JD	Journal ID	Journal Descr JD	Bus Unit and Long Descr JD	Resp Center ID CB	Oper Unit ID CB	Res Type	Product ID CB	Invoice ID JD	Period Activity
201608	402ED301P	Estimate and reversal of estim	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			$77,000.00
	402ED311P	To record prior month final re	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			$1,401,267.55
	406WOJS101	Write off Midwest Gen balances	75930 - AHFS - OH NonReg MV	5930	AHFO	99810			$117,056.15
201608									$1,595,323.70

DUKE ENERGY

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Fiscal Year.
Currency Code: USD

GENERAL LEDGER REPORT - DETAIL

Business Unit(s):

Account Tree: WTB_GAAP_REPORT
Account(s):

Fiscal Year and Period JD	Journal ID	Journal Descr JD	Bus Unit and Long Descr JD	Resp Center ID CB	Oper Unit ID CB	Res Type	Product ID CB	Invoice ID JD	Period Activity
201609	402ED301P	Estimate and reversal of estim	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			$0.00
	402ED311P	To record prior month final re	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			$1,401,267.24
201609									$1,401,267.24

Fiscal Year and Period JD	Journal ID	Journal Descr JD	Bus Unit and Long Descr JD	Resp Center ID CB	Oper Unit ID CB	Res Type	Product ID CB	Invoice ID JD	Period Activity
201610	402ED301P	Estimate and reversal of estim	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			$0.00
	402ED311P	To record prior month final re	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			$1,401,267.28
201610									$1,401,267.28

Fiscal Year and Period JD	Journal ID	Journal Descr JD	Bus Unit and Long Descr JD	Resp Center ID CB	Oper Unit ID CB	Res Type	Product ID CB	Invoice ID JD	Period Activity
201611	402ED301P	Estimate and reversal of estim	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			$0.00
	402ED311P	To record prior month final re	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			$1,401,267.15
201611									$1,401,267.15

Fiscal Year and Period JD	Journal ID	Journal Descr JD	Bus Unit and Long Descr JD	Resp Center ID CB	Oper Unit ID CB	Res Type	Product ID CB	Invoice ID JD	Period Activity
201612	402ED301P	Estimate and reversal of estim	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			($61,000.00)
	402ED311P	To record prior month final re	75930 - AHFS - OH NonReg MV	S839	AHFO	99810			$1,340,198.47
201612									$1,279,198.47

			Sum:			$16,636,788.95
						$16,636,788.95

Duke Energy.

Beginning Accounting Period: 1

Ending Accounting Period: 12

GENERAL LEDGER REPORT - DETAIL

Business Unit(s): 75001

Account Tree: WTB_GAAP_REPORT

Account(s): 0566100

Fiscal Year: 2016

Currency Code: USD

0566100 - Misc Trans-Trans Lines Related

75001 - DE Ohio Commercial Power

Fiscal Year and Period	Journal ID	Journal Description	per Unit IC	ournal Date JC	Operator ID JD	Affiliate ID CB	Period Activity
201601	RTEP-1601	Reclass PJM DEK RTEP charges t	OHCP	1/31/2016	JRK8391		287,446.75
		Sum of Activity in 201601:					287,446.75

Fiscal Year and Period	Journal ID	Journal Description	per Unit IC	ournal Date JC	Operator ID JD	Affiliate ID CB	Period Activity
201602	RTEP-1602	Reclass PJM DEK RTEP charges t	OHCP	2/29/2016	JRK8391		285,776.77
		Sum of Activity in 201602:					285,776.77

Fiscal Year and Period	Journal ID	Journal Description	per Unit IC	ournal Date JC	Operator ID JD	Affiliate ID CB	Period Activity
201603	RTEP-1603	Reclass PJM DEK RTEP charges t	OHCP	3/31/2016	JRK8391		285,900.29
		Sum of Activity in 201603:					285,900.29

Fiscal Year and Period	Journal ID	Journal Description	per Unit IC	ournal Date JC	Operator ID JD	Affiliate ID CB	Period Activity
201604	RTEP-1604	Reclass PJM DEK RTEP charges t	OHCP	4/30/2016	PLARKINS		285,776.77
		Sum of Activity in 201604:					285,776.77

Fiscal Year and Period	Journal ID	Journal Description	per Unit IC	ournal Date JC	Operator ID JD	Affiliate ID CB	Period Activity
201605	RTEP-1605	Reclass PJM DEK RTEP charges t	OHCP	5/31/2016	PLARKINS		286,721.62
		Sum of Activity in 201605:					286,721.62

Fiscal Year and Period	Journal ID	Journal Description	per Unit IC	ournal Date JC	Operator ID JD	Affiliate ID CB	Period Activity
201606	RTEP-1606	Reclass PJM DEK RTEP charges t	OHCP	6/30/2016	PLARKINS		290,770.29
		Sum of Activity in 201606:					290,770.29

Fiscal Year and Period	Journal ID	Journal Description	per Unit IC	ournal Date JC	Operator ID JD	Affiliate ID CB	Period Activity

Duke Energy

GENERAL LEDGER REPORT - DETAIL

Business Unit(s): 75001

Account Tree: WTB_GAAP_REPORT

Account(s): 0566100

Beginning Accounting Period: 1

Ending Accounting Period: 12

Fiscal Year: 2016

Currency Code: USD

201607	RTEP-1607	Reclass PJM DEK RTEP charges t	OHCP	7/31/2016	PLARKINS		269,515.06
		Sum of Activity in 201607:					269,515.06

Fiscal Year and Period	Journal ID	Journal Description	per Unit IC	ournal Date JC	Operator ID JD	Affiliate ID CB	Period Activity
201608	RTEP-1608	Reclass PJM DEK RTEP charges t	OHCP	8/31/2016	MLI1		285,261.60
		Sum of Activity in 201608:					285,261.60

Fiscal Year and Period	Journal ID	Journal Description	per Unit IC	ournal Date JC	Operator ID JD	Affiliate ID CB	Period Activity
201609	RTEP-1609	Reclass PJM DEK RTEP charges t	OHCP	9/30/2016	MLI1		285,261.60
		Sum of Activity in 201609:					285,261.60

Fiscal Year and Period	Journal ID	Journal Description	per Unit IC	ournal Date JC	Operator ID JD	Affiliate ID CB	Period Activity
201610	RTEP-1610	Reclass PJM DEK RTEP charges t	OHCP	10/31/2016	MLI1		285,520.11
		Sum of Activity in 201610:					285,520.11

Fiscal Year and Period	Journal ID	Journal Description	per Unit IC	ournal Date JC	Operator ID JD	Affiliate ID CB	Period Activity
201611	RTEP-1611	Reclass PJM DEK RTEP charges t	OHCP	11/30/2016	MLI1		285,261.60
		Sum of Activity in 201611:					285,261.60

Fiscal Year and Period	Journal ID	Journal Description	per Unit IC	ournal Date JC	Operator ID JD	Affiliate ID CB	Period Activity
201612	RTEP-1612	Reclass PJM DEK RTEP charges t	OHCP	12/31/2016	MLI1		285,520.11
		Sum of Activity in 201612:					285,520.11

		Sum:					3,416,732.57

KyPSC Case No. 2017-00321
AG-DR-01-014 Attachment 2
Page 4 of 4

Duke Energy Kentucky, Inc.
RTEP Charges
January 2013 Through September 2017

Month	Type	Amount
Jan-13	Actual	207,081
Feb-13	Actual	207,081
Mar-13	Actual	207,081
Apr-13	Actual	207,081
May-13	Actual	207,081
Jun-13	Actual	203,510
Jul-13	Actual	205,205
Aug-13	Actual	205,205
Sep-13	Actual	205,205
Oct-13	Actual	205,205
Nov-13	Actual	205,205
Dec-13	Actual	205,205
Jan-14	Actual	230,907
Feb-14	Actual	231,965
Mar-14	Actual	231,474
Apr-14	Actual	231,474
May-14	Actual	231,474
Jun-14	Actual	256,263
Jul-14	Actual	263,975
Aug-14	Actual	263,975
Sep-14	Actual	269,733
Oct-14	Actual	264,654
Nov-14	Actual	264,654
Dec-14	Actual	264,654
Jan-15	Actual	286,494
Feb-15	Actual	286,494
Mar-15	Actual	286,494
Apr-15	Actual	286,494
May-15	Actual	286,494
Jun-15	Actual	290,467
Jul-15	Actual	289,385
Aug-15	Actual	289,385
Sep-15	Actual	289,385
Oct-15	Actual	289,385
Nov-15	Actual	289,385
Dec-15	Actual	289,385
Jan-16	Actual	287,691
Feb-16	Actual	287,691
Mar-16	Actual	287,691
Apr-16	Actual	288,574
May-16	Actual	294,997
Jun-16	Actual	277,270
Jul-16	Actual	293,275
Aug-16	Actual	293,275
Sep-16	Actual	293,275
Oct-16	Actual	293,275
Nov-16	Actual	293,275
Dec-16	Actual	293,275
Jan-17	Actual	298,395
Feb-17	Actual	295,098
Mar-17	Actual	301,269
Apr-17	Actual	298,254
May-17	Actual	299,944
Jun-17	Actual	293,547
Jul-17	Actual	294,178
Aug-17	Actual	294,178
Sep-17	Actual	294,178

EXHIBIT ____ (LK-6)

Duke Energy Kentucky
Case No. 2017-00321
Attorney General's First Set Data Requests
Date Received: October 27, 2017

AG-DR-01-015

REQUEST:

Refer to WPD-2.34a.

a. Provide the RTEP expense for each month January 2015 through the most recent month for which actual information is available and thereafter the projected RTEP expense for the remainder of 2017 and 2018 through the end of the test year.

b. Provide all support for the projected RTEP charges through the end of the test year and the allocations of the DEO/DEK load zone to DEK.

RESPONSE:

a.

Month	Type	Amount
Jan-15	Actual	286,494
Feb-15	Actual	286,494
Mar-15	Actual	286,494
Apr-15	Actual	286,494
May-15	Actual	286,494
Jun-15	Actual	290,467
Jul-15	Actual	289,385
Aug-15	Actual	289,385
Sep-15	Actual	289,385
Oct-15	Actual	289,385
Nov-15	Actual	289,385
Dec-15	Actual	289,385
Jan-16	Actual	287,691
Feb-16	Actual	287,691
Mar-16	Actual	287,691
Apr-16	Actual	288,574
May-16	Actual	294,997
Jun-16	Actual	277,270

Jul-16	Actual	293,275	
Aug-16	Actual	293,275	
Sep-16	Actual	293,275	
Oct-16	Actual	293,275	
Nov-16	Actual	293,275	
Dec-16	Actual	293,275	
Jan-17	Actual	298,395	
Feb-17	Actual	295,098	
Mar-17	Actual	301,269	
Apr-17	Actual	298,254	
May-17	Actual	299,944	
Jun-17	Actual	293,547	
Jul-17	Actual	294,178	
Aug-17	Actual	294,178	
Sep-17	Actual	294,178	
Oct-17	Projected	354,167	(1)
Nov-17	Projected	354,167	(1)
Dec-17	Projected	354,167	(1)
Jan-18	Projected	396,667	
Feb-18	Projected	396,667	
Mar-18	Projected	396,667	
Apr-18	Projected	335,866	
May-18	Projected	335,866	
Jun-18	Projected	335,866	
Jul-18	Projected	335,866	
Aug-18	Projected	335,866	
Sep-18	Projected	335,866	
Oct-18	Projected	335,866	
Nov-18	Projected	335,866	
Dec-18	Projected	335,866	
Jan-19	Projected	335,866	
Feb-19	Projected	335,866	
Mar-19	Projected	335,867	

(1) These are the budgeted amounts for RTEP but were inadvertently excluded from Duke Energy Kentucky's budget.

b. See the response to AG-DR-01-014. See AG-DR-01-015 Attachment for support for the allocation of the projected RTEP expense to Duke Energy Kentucky.

PERSON RESPONSIBLE: Robert H. Pratt

Duke Energy Kentucky, Inc.
Transmission Enhancement Charges
PJM Billing Line Item 1108

	2013	2014	2015	2016	2017	Total
DEO	13,687,269.69	14,651,369.15	16,996,883.21	16,506,846.86	12,822,134.03	74,664,502.94
	84.71%	82.98%	83.09%	82.57%	82.77%	83.19%
DEK	2,470,144.92	3,005,198.14	3,459,248.05	3,483,568.52	2,669,041.80	15,087,201.43
	15.29%	17.02%	16.91%	17.43%	17.23%	16.81%
Total DEOK	16,157,414.61	17,656,567.29	20,456,131.26	19,990,415.38	15,491,175.83	89,751,704.37

EXHIBIT ____ (LK-7)

STAFF-DR-02-018

REQUEST:

Refer to the Henning Testimony, page 35, lines 5-11. Provide the annual amount of vegetation management expense for the five years ending in 2016, the base period, and the test year.

RESPONSE:

Period	Distribution	Transmission	Total
2012	1,595,813	178,645	1,774,458
2013	2,011,292	191,717	2,203,009
2014	2,123,558	185,715	2,309,273
2015	1,930,287	125,297	2,055,584
2016	1,812,789	242,781	2,055,570
Base Period	1,370,074	230,941	1,601,015
Test Year	4,036,724	443,163	4,479,887

PERSON RESPONSIBLE: Robert H Pratt/David Doss

EXHIBIT ____ (LK-8)

REQUEST:

Refer to the Doss Testimony, page 5, lines 13-14, and the Direct Testimony of Robert H. "Beau" Pratt ("Pratt Testimony"), page 21, lines 4-6.

a. Explain the discrepancy in the testimony of the witnesses listed above as to the timeframe utilized for developing outage and production maintenance expenses in the test year.

b. Provide the actual fiscal/calendar years used to determine the "average" outage and production maintenance expenses.

c. Refer to the Pratt Testimony, page 21. What was the amount of production maintenance expense included in the forecast and why was it understated?

d. Confirm there are no outage and production maintenance expenses related to Miami Fort Unit 6 included in the years utilized for the proposed amount of the outage/production maintenance expense.

e. Provide the forecasted outage/production maintenance expense by account number for the six years included in the Application and for each year through March 2025.

f. Provide a history of the date and cost of generator overhauls by account number for each unit by year since 2006.

g. Provide a schedule showing the date and cost of future generator overhauls by account number by year through 2025.

h. Provide a history of the date and cost of turbine overhauls by account number for each unit by year since 2006.

i. Provide a schedule showing the date and cost of future turbine overhauls by account number by year through 2025.

RESPONSE:

a. The Pratt Testimony referenced refers to the East Bend total maintenance expense proforma adjustment shown on Schedule D-2.30, and was made to correct an understated budget. This proforma adjustment used a five year average of actual data for the years 2012 through 2016. The Doss Testimony referenced refers to an outage expense adjustment, a portion of total maintenance expense, shown on Schedule D-2.33 which was made to normalize planned outage expenses. This proforma adjustment used a six year average consisting of four years of actual data, years 2013 through 2016, and two years of projected data, years 2017 and 2018.

b. See response to item a.

c. As shown on WPD-2.30a, the amount of East Bend maintenance expense included in the forecasted test period was $5,575,440. This amount was based on a budget that was erroneously understated as can be evidenced by the historical data used in determining proforma adjustment D-2.30.

d. Confirmed.

e. See STAFF-DR-02-23e Attachment for details supporting planned outage expense by account number for 2013-2021. The company has not prepared a forecast for periods beyond 2021.

f. None.

g. None.

h. There was one turbine overhaul since 2006 at East Bend Unit 2 and the O&M costs were as follows:

    a. 2007 spend – Acct 513 – $653,175

    b. 2008 spend – Acct 513 – $883,224

i. Through 2021, there is one turbine overhaul planned for the spring of 2018. Forecasting is completed for a five year period and, as such, forecasted data is not available beyond 2021. O&M details of the 2018 turbine overhaul are as follows:

    a. 2017 projected spend – Account 513 – $148,622

    b. 2018 projected spend – Account 513 – $3,774,163

PERSON RESPONSIBLE: Robert H. Pratt / David L. Doss, Jr.

Forecasted outage/production maintenance expense by account number

East Bend

Account	2013	2014	2015	2016	2017	2018	2019	2020	2021
500	637	93	-	1,827	-	-	-	-	-
506	-	2,972	-	26,477	-	-	-	-	-
510	-	6,539	-	631	-	-	-	-	-
511	77,329	106,560	6,611	173,083	-	-	-	-	-
512	3,016,791	8,631,694	2,735,845	4,989,198	739,672	6,854,375	-	4,323,819	4,969,923
513	851,328	5,146,747	101,415	606,932	216,761	5,255,302	-	1,267,096	1,456,437
514	100,862	103,903	6,296	3,043,657	2,918	2,966	-	17,057	19,606
921	-	-	-	85	-	-	-	-	-
925	-	-	-	1,427	-	-	-	-	-
926	53,419	64,386	17,886	54,203	446	453	-	2,607	2,997
	4,100,366	14,062,894	2,868,053	8,897,520	959,797	12,113,096	-	5,610,579	6,448,963

Woodsdale

Account	2013	2014	2015	2016	2017	2018	2019	2020	2021
553	-	-	-	2,271,112	4,529,358	-	-	838,384	-

Notes

a) 2013-2018 reference WPD-2.33a

b) Forecasting is completed for a 5-year period. Forecast is available for 2017-2021 and does not extend to 2025.

EXHIBIT ____ (LK-9)

Duke Energy Kentucky
Case No. 2017-00321
Attorney General's First Set Data Requests
Date Received: October 27, 2017

AG-DR-01-018

REQUEST:

Provide the amount of incentive compensation expense pursuant to the Duke Energy Short Term Incentive ("STI") Plan included in the test year revenue requirement for each target metric used for this plan during the test year. Separately provide the expense projected to be incurred directly by the Company and the costs incurred through charges from DEBS, DEO, and/or any other affiliates. In addition, provide these amounts by FERC O&M and/or A&G expense account/subaccount.

RESPONSE:

Please see Attachment AG-DR-01-018 Attachment 1.

PERSON RESPONSIBLE: Jeffrey R. Setser

Incentive Compensation:

Incentive Compensation: Incentive Target Metric

Response:

NOTE: Response for Question #18 pertains to ELECTRIC operations ONLY.

Total budgeted incentive Apr - Dec 2018

			Affiliates							
Measure	Weight	DE Kentucky	DE Carolinas	Service Company	DE Ohio	DE Indiana	DE Progress	DE Florida	Piedmont	Total to DE Kentucky
EPS	30%	$ 158,524	$ 54,752	$ 618,470	$ 18,145	$ 21,229	$ 10,817	$ 2,352	$ 41	$ 884,329
Operational Excellence	15%	79,262	27,376	309,235	9,072	10,615	5,408	1,176	20	442,164
Customer Satisfaction (CSAT)	5%	26,421	9,125	103,078	3,024	3,538	1,803	392	7	147,388
Team	50%	264,207	91,253	1,030,783	30,241	35,382	18,028	3,919	68	1,473,882
Total	100%	$ 528,415	$ 182,505	$ 2,061,566	$ 60,482	$ 70,764	$ 36,056	$ 7,839	$ 136	$ 2,947,763

Total budgeted incentive Jan - Mar 2019

			Affiliates							
Measure	Weight	DE Kentucky	DE Carolinas	Service Company	DE Ohio	DE Indiana	DE Progress	DE Florida	Piedmont	Total to DE Kentucky
EPS	30%	$ 67,688	$ 18,388	$ 205,299	$ 5,153	$ 6,872	$ 3,752	$ 1,886	$ -	$ 309,039
Operational Excellence	15%	33,844	9,194	102,650	2,576	3,436	1,876	943	-	154,520
Customer Satisfaction (CSAT)	5%	11,281	3,065	34,217	859	1,145	625	314	-	51,507
Team	50%	112,814	30,646	342,166	8,588	11,454	6,254	3,144	-	515,065
Total	100%	$ 225,628	$ 61,293	$ 684,331	$ 17,176	$ 22,908	$ 12,508	$ 6,287	$ -	$ 1,030,131

Incentive Compensation: By FERC account

Response:

NOTE: Response for Question #18 pertains to ELECTRIC operations ONLY.

Incentive Budget Apr-Dec 2018		
		Calc 3 qtrs of
Company	FERC Acct	2018
18400 - Incentives Allocated		
DE Kentucy	107	215,840
	186.1	39,228
	549	(5,567)
	586	6,417
	587	2,193
	588	2,940
	593	1
	717	-
	735	-
	742	-
	863	-
	871	-
	874	-
	878	-
	879	-
	887	
	889	-
	892	-
	893	-
	894	-
	901	3,469
	903	-
	908	-
	930.2	-
DE Kentucy		264,521
DE Carolinas	107	16,242
	108	9,813
	183	3,793
	186.1	-
	417.1	693
	500	696
	501	2,507
	506	46
	510	1,409
	511	2,745
	549	1
	551	1,716
	557	22,149
	566	1,510
	571	697
	580	35
	583	5,285
	586	111
	588	4,792
	597	265
	880	
	901	1,377
	903	19,172
	910	5,386
	912	25,118
	920	56,948
DE Carolinas		182,505

Incentive Budget Jan-Mar 2019		
		Calc 1 qtr of
Company	FERC Acct	2019
18400 - Incentives Allocated		
DE Kentucy		
	107	131,191
	186.1	2,963
	549	(1,856)
	586	2,139
	587	731
	588	1,120
	717	-
	735	-
	742	-
	863	
	871	
	874	
	878	
	879	
	887	
	889	
	892	
	893	-
	894	-
	901	1,156
	903	
	908	-
	930.2	-
DE Kentucy		137,444
DE Carolinas		
	107	5,236
	108	3,285
	183	1,264
	186.1	-
	417.1	231
	500	232
	501	837
	506	15
	510	1,455
	511	942
	551	582
	557	6,744
	561	197
	566	503
	580	12
	583	1,762
	586	37
	588	1,597
	597	88
	880	-
	901	459
	903	6,189
	910	2,059
	912	8,502
	920	19,063
DE Carolinas		61,293

Incentive Compensation: By FERC account

Response:

NOTE: Response for Question #18 pertains to ELECTRIC operations ONLY.

Incentive Budget Apr-Dec 2018		
		Calc 3 qtrs of
Company	FERC Acct	2018
Service Company	107	289,103
	108	17,469
	163	73,775
	186.1	141,939
	228.2	97
	253	-
	417.1	4,198
	426.4	14,231
	500	137,134
	501	8,552
	502	18,392
	506	24,021
	510	193,161
	511	3,674
	546	13,184
	548	312
	549	5,770
	551	16,620
	557	37,791
	561	43,275
	566	3,194
	569.2	4,434
	570	21
	571	1,263
	580	89
	581	28,784
	587	5,993
	588	27,541
	593	3,167
	595	109
	807	-
	874	-
	878	-
	879	-
	880	-
	903	90,450
	910	19,761
	912	7,103
	913	23
	920	398,183
	921	2,471
	923	11
	930.1	751
Service Company		1,636,046
DE Ohio	107	-
	186.1	7,036
	557	1,296
	586	529
	588	1,595
	597	16,378
	880	-
	901	2,699
	903	5,540
	912	16,176
DE Ohio		51,247
DE Indiana	107	24,513
	108	30,943
	501	1,993
	511	263
	547	503
	551	403
	557	4,631
	597	928
	901	1,298
	903	18
	920	5,271
DE Indiana		70,764

Incentive Budget Jan-Mar 2019		
		Calc 1 qtr of
Company	FERC Acct	2019
Service Company		
	107	86,029
	108	5,138
	163	24,592
	186.1	66,127
	228.2	32
	253	-
	417.1	1,443
	426.4	4,754
	500	45,399
	501	2,851
	502	6,230
	506	8,007
	510	64,049
	511	1,227
	546	3,945
	548	104
	549	1,923
	551	5,321
	557	13,117
	561	14,301
	566	1,080
	569.2	608
	570	7
	580	30
	581	4,200
	587	1,998
	588	7,061
	593	1,056
	595	36
	807	
	874	-
	878	
	879	-
	880	-
	903	30,478
	910	5,427
	912	2,598
	913	8
	920	129,661
	921	499
	923	4
	930.1	259
Service Company		539,599
DE Ohio	107	-
	557	432
	586	176
	588	532
	597	5,459
	880	-
	901	900
	903	1,847
	912	5,392
		14,737
DE Ohio		
DE Indiana	107	8,187
	108	10,314
	501	664
	511	88
	547	168
	551	139
	557	1,404
	597	309
	901	433
	903	6
	920	1,196
DE Indiana		22,908

Incentive Compensation: By FERC account

Response:

NOTE: Response for Question #18 pertains to ELECTRIC operations ONLY.

Incentive Budget Apr-Dec 2018		
		Calc 3 qtrs of
Company	FERC Acct	2018
DE Progress	107	3,030
	186.1	93
	417.1	960
	500	1,091
	501	1,554
	511	27
	551	124
	557	7,077
	580	40
	588	254
	880	-
	903	1,146
	910	83
	912	3,751
	920	16,825
DE Progress		36,056
DE Florida	107	92
	501	20
	511	129
	547	16
	551	97
	557	677
	597	840
	903	70
	910	23
	912	478
	920	5,397
DE Florida		7,839
Piedmont	163	-
	742	-
	807	-
	863	-
	874	-
	878	-
	879	-
	880	-
	901	136
	930.2	-
Piedmont		136
18401 - Incentives Allocated-Union		
Service Company	107	6,044
	163	12,946
	186.1	2,684
	510	76
	551	50
	562	1,109
	563	282
	566	16
	569	421
	570	4,042
	571	22
	582	1,778
	588	43
	591	154
	592	7,192
	903	3,236
	910	25
	920	355
Service Company		40,475
DE Ohio	107	245
	186.1	1,918
	586	291
	588	2,509
	597	3,046
	901	896
	902	329
	903	1
DE Ohio		9,235

Incentive Budget Jan-Mar 2019		
		Calc 1 qtr of
Company	FERC Acct	2019
DE Progress	107	901
	186.1	31
	417.1	229
	500	358
	501	518
	511	9
	551	42
	557	3,066
	580	13
	588	85
	880	-
	903	212
	910	28
	912	1,124
	920	5,892
DE Progress		12,508
DE Florida	107	58
	501	7
	511	43
	547	5
	551	33
	557	342
	581	3,291
	597	280
	903	199
	910	8
	912	154
	920	1,867
DE Florida		6,287
18401 - Incentives Allocated-Union		
DE Kentucy	107	24,805
	108	88
	416	39
	500	804
	501	4,032
	502	21,459
	505	3,739
	506	623
	511	4,940
	512	5,517
	514	1,982
	548	3,035
	549	3,302
	583	243
	584	8
	586	407
	587	662
	588	2,707
	593	6,732
	594	579
	595	38
	596	19
	597	4
	717	-
	735	-
	863	-
	871	
	874	-
	878	-
	879	-
	887	-
	889	
	892	-
	893	
	894	-
	901	504
	903	1,915
	908	-
DE Kentucy		88,183

Incentive Compensation: By FERC account

Response:

NOTE: Response for Question #18 pertains to ELECTRIC operations ONLY.

Incentive Budget Apr-Dec 2018		
Company	FERC Acct	Calc 3 qtrs of 2018
DE Kentucy	107	71,579
	108	263
	416	118
	500	2,364
	501	11,928
	502	63,517
	505	11,067
	506	4,978
	511	14,637
	512	16,354
	514	5,875
	548	8,802
	549	8,836
	583	730
	584	25
	586	4,450
	587	1,986
	588	7,004
	593	20,195
	594	1,737
	595	114
	596	66
	597	9
	717	-
	735	-
	871	-
	874	-
	878	
	879	-
	887	-
	889	-
	892	-
	893	-
	894	-
	901	1,513
	903	5,745
	908	-
DE Kentucy		263,894
1E002 - Exec Short Term Incent		
Service Company	107	12,258
	108	8,306
	163	3,352
	186.1	26,655
	417.1	953
	426.4	24,241
	500	36,572
	506	84
	510	548
	511	2,765
	546	4,360
	557	6,308
	561	1,542
	566	137
	588	492
	880	-
	903	7,626
	910	477
	912	4,869
	920	122,163
	921	121,336
Service Company		385,045
Total to DE Kentucky		$ 2,947,763

Incentive Budget Jan-Mar 2019		
Company	FERC Acct	Calc 1 qtr of 2019
Service Company	107	1,177
	163	4,315
	186.1	1,566
	510	25
	551	17
	562	422
	563	94
	566	5
	569	140
	570	1,347
	571	7
	582	759
	588	14
	591	51
	592	2,397
	903	1,079
	910	8
	920	120
Service Company		13,546
DE Ohio	107	82
	586	97
	588	836
	597	1,015
	901	299
	902	110
	903	0
DE Ohio		2,439
1E002 - Exec Short Term Incent		
Service Company	107	4,132
	108	2,865
	163	1,157
	186.1	9,196
	417.1	329
	426.4	8,363
	500	12,617
	506	29
	510	189
	511	954
	546	1,504
	557	2,176
	561	532
	566	47
	588	170
	880	-
	903	2,631
	910	164
	912	1,680
	920	42,052
	921	40,399
Service Company		131,187
		$ 1,030,131
		$ -

EXHIBIT ____ (LK-10)

AG-DR-01-019

REQUEST:

Provide the amount of incentive compensation expense pursuant to the Duke Energy Long Term Incentive ("LTI") Plan included in the test year revenue requirement for each target metric used for this plan during the test year. Separately provide the costs projected to be incurred directly by the Company and the costs incurred through charges from DEBS, DEO, and/or any other affiliates. In addition, provide these amounts by FERC O&M and/or A&G expense account.

RESPONSE:

Please see Attachment AG-DR-01-019 Attachment 1.

PERSON RESPONSIBLE: Jeffrey R. Setser

Duke Energy Kentucky
Test Period: 4/1/2018 - 3/31/2019

Incentive Compensation

Response:

NOTE: Response for Question #19 pertains to ELECTRIC operations ONLY.

Restricted Stock Units (RSUs) [a]

		Affiliates							
	DE Kentucky	DE Carolinas	Service Company	DE Ohio	DE Indiana	DE Progress	DE Florida	Piedmont	Total to DE Kentucky
Total	$ -	$ -	$ 684,410	$ -	$ -	$ -	$ -	$ -	$ 684,410

Performance Shares

		Affiliates							
Measure	DE Kentucky	DE Carolinas	Service Company	DE Ohio	DE Indiana	DE Progress	DE Florida	Piedmont	Total to DE Kentucky
EPS	$ -	$ -	$ 160,503	$ -	$ -	$ -	$ -	$ -	$ 160,503
TSR	-	-	100,201	-	-	-	-	-	100,201
TICR	-	-	60,302	-	-	-	-	-	60,302
ROE	-	-	39,527	-	-	-	-	-	39,527
Total	$ -	$ -	$ 360,533	$ -	$ -	$ -	$ -	$ -	$ 360,533

(a) There are no target metrics associated with RSU's. Incentive is earned if participant is employed at the end of the vesting period.

Duke Energy Kentucky
Test Period: 4/1/2018 - 3/31/2019

Incentive Compensation - By FERC Account

Response:

NOTE: Response for Question #19 pertains to ELECTRIC operations ONLY.

Time Hierarchy Y-Q-M	(Multiple Items)
Business Unit Hierarchy	(Multiple Items)

Row Labels	MTD Budget Amount
1E200 - Restricted Stock Units	**684,410**
110_SERVICE_COMPANY	**684,410**
107	22,114
108	14,483
163	7,592
186.1	57,447
417.1	1,014
426.4	40,336
500	52,517
506	176
510	1,307
511	4,928
546	8,066
557	11,133
561	3,088
566	876
588	1,047
903	12,157
910	932
912	9,615
920	219,459
921	191,405
930.2	24,720
536_DEK	**0**
500	0
506	0
510	0
546	0
920	0
921	0
CORP	**684,410**
CORP (FY)	**684,410**
NON_CORP	**0**
NON_CORP (FY)	**0**
1E202 - Performance Award	**360,533**
110_SERVICE_COMPANY	**360,533**
107	4,067
426.4	15,295

Duke Energy Kentucky
Test Period: 4/1/2018 - 3/31/2019

Incentive Compensation - By FERC Account

Response:

NOTE: Response for Question #19 pertains to ELECTRIC operations ONLY.

Time Hierarchy Y-Q-M	(Multiple Items)
Business Unit Hierarchy	(Multiple Items)

Row Labels	MTD Budget Amount
500	18,741
511	713
557	4,940
903	4,848
910	54
912	4,300
920	144,414
921	163,162
536_DEK	**0**
500	0
920	0
CORP	**360,533**
CORP (FY)	**360,533**
NON_CORP	**0**
NON_CORP (FY)	**0**
Grand Total	**1,044,943**

EXHIBIT ____ (LK-11)

Duke Energy Kentucky
Case No. 2017-00321
Attorney General's First Set Data Requests
Date Received: October 27, 2017

AG-DR-01-022

REQUEST:

Refer to Table 1 of Mr. Wathen's Direct Testimony at page 33. For each of the projected regulatory asset balances listed, please provide a schedule showing each of the individual expenses (by FERC O&M or A&G expense account) or costs deferred that sum to the balances provided.

RESPONSE:

a. For AMI Opt Out

   See workpaper WPD-2.31a. and AG-DR-01-022(a) ATTACHMENT.

b. For East Bend Deprecation

   See workpapers WPD-2.21a and WPD-2.21b.

c. For East Bend O&M

   See workpaper WPD-2.31a and response to AG-DR-01-023.

d. Carbon Management Research

   Pursuant to a Commission in Case No. 2008-00308, the Company has made $200,000 payments, annually, since 2009 to the Carbon Management Research Group. See workpaper WPD2-31a for FERC account number.

e. AMI Meter Change-Out

   See workpaper WPD2-16a.

PERSON RESPONSIBLE: William D. Wathen Jr.

EXHIBIT ____ (LK-12)

REQUEST:

Refer to the Application, Volume 11, Tab 51; Duke Kentucky's responses to Staff's First Request for Information to Duke Kentucky ("Staff's First Request"). Item 66; and the Direct Testimony of Thomas Silinski ("Silinski Testimony") beginning at page 34 regarding employee benefit plans.

a. Provide the jurisdictional employee medical insurance adjustment assuming the following: Total Healthcare/Medical Cost for Each Level of Coverage = Company Paid Portion of Premium + Employee Contribution to Premium. Continue to assume that the employee would pay 21 percent of the total cost for single coverage and 33 percent of the total cost for all other types of coverage, compared to the amount of healthcare/medical insurance expense incurred the test year.

b. Provide the jurisdictional dental insurance adjustment in the test year assuming employees would pay 60 percent of the total cost of coverage. Calculate the amount as follows: Total Dental Cost for Each Level of Coverage = Company Paid Portion of Premium + Employee Contribution to Premium.

c. Provide a schedule that identifies the jurisdictional cost for providing long-term disability insurance.

d. Provide a schedule that identifies the costs for providing group life insurance coverage for coverage over $50,000.

e. For employees who participate in a defined benefit plan, provide the total and jurisdictional amount of matching contributions made on behalf of employees who also participate in any 401(k) retirement savings account.

f. Provide the information requested in items a. through e. that are passed through from Duke Energy or other affiliated companies.

RESPONSE:

Please see STAFF-DR-02-005 Attachment

PERSON RESPONSIBLE: Tom Silinski

Question No. 5 - Second Request
Responding Witness: Tom Silinski

The below is an analysis of the Test Period numbers:

A.

	Kentucky		Allocated from Affiliates	
Total Costs:				
Single Coverage	356,507		230,865	
Other Coverage	1,728,327		1,119,222	
Total	2,084,834		1,350,087	
Employee Cost:				
Single Coverage	71,301	20%	46,173	20%
Other Coverage	570,348	33%	369,343	33%
Total	641,649		415,516	
Employer Cost:				
Single Coverage	285,206		184,692	
Other Coverage	1,157,979		749,879	
Total	1,443,185		934,571	
Total KY Cost (Previously submitted)	1,737,361		1,125,073	
Change	294,176		190,502	

Note: The calculations above only look at the premium cost share. It does not reflect the out of pocket costs incurred by the employee (coinsurance, copays, deductibles). For medical coverage, the employee pays on average 17% of the premium and 34% of the total cost of coverage.

B.

	Kentucky		Allocated from Affiliates	
Total Costs:				
Single Coverage	20,376		13,694	
Other Coverage	136,786		91,931	
Total	157,162		105,625	
Employee Cost:				
Single Coverage	12,225	60%	8,216	60%
Other Coverage	82,072	60%	55,158	60%
Total	94,297		63,375	
Employer Cost:				
Single Coverage	8,150		5,478	
Other Coverage	54,714		36,772	
Total	62,865		42,250	
Total KY Cost (Previously submitted)	102,627		68,973	
Change	39,762		26,723	

Note: The calculations above only look at the premium cost share. It does not reflect the out of pocket costs incurred by the employee (coinsurance, copays, deductibles). For dental coverage, the employee pays on average 35% of the premium and 56% of the total cost of coverage.

C. For the Test period, the jurisdictional cost for providing salary continuation insurance is expected to be the following

Kentucky	45,501
Allocated from Affiliates	30,460
Total	75,961

D. For the Test period, the jurisdictional cost for providing life insurance coverage over $50k is expected to be the following:

Kentucky	6,594
Allocated from Affiliates	4,414
Total	11,008

E. For the Test period, the jurisdictional cost of company match for individuals with a DC and DB plan is expected to be the following:

Kentucky	991,325
Allocated from Affiliates	588,436
Total	1,579,761

F. See 'allocated from affiliates' portion of A-E above

EXHIBIT ____ (LK-13)

AG-DR-01-023

REQUEST:

Refer to the Direct Testimony of Ms. Lawler at 12 wherein she states:

The third regulatory asset is associated with the Company's acquisition of the 31 percent interest in the East Bend Generating Station (East Bend) as approved in Case No. 2014-0020 I. In that case, the Commission authorized the Company to defer the incremental operations and maintenance expenses above amounts that were currently reflected in base rates associated with the acquisition of the 31 percent interest in East Bend, the incremental retirement costs associated with the retirement of Miami Fort Unit 6 Generating Station (MF6), carrying costs on the unrecovered balance based upon the Company's actual cost of debt, and any other incremental costs related to the assumed liabilities or otherwise necessary to effectuate the purchase of East Bend.

a. Provide a copy of all calculations supporting each of the components of the deferrals included in this regulatory asset, including, but not limited to, the calculation of the carrying costs based on the Company's cost of debt.

b. Indicate if the regulatory asset reflects any offsets for the reductions in operating expenses (non-fuel O&M expense, depreciation, ad valorem taxes, etc.) due to the retirement of MF6. If not, explain why not.

RESPONSE:

a. See AG-DR-01-023 Attachment.

b. As noted on AG-DR-01-023, the regulatory asset includes offsets for reductions in operating expenses due to the retirement of MF6.

PERSON RESPONSIBLE: Sarah E. Lawler

Duke Energy Kentucky, Inc.
East Bend Deferral Analysis

DEK East Bend Deferral Forecast	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15
O&M	$1,189,456.35	$1,415,405.40	$1,386,208.51	$1,213,065.37	$1,099,821.53	$833,246.58	$828,586.04	$815,015.99	$831,441.71	$1,036,647.52
Reagents EB Incremental	$369,911.00	$318,620.60	$243,276.60	$276,275.70	$328,775.80	$279,073.10	$331,356.90	$274,584.20	$300,394.40	$249,431.50
Total Incremental	$1,559,367.35	$1,734,026.00	$1,629,485.11	$1,489,341.07	$1,428,597.33	$1,112,319.68	$1,159,942.94	$1,089,600.19	$1,131,836.11	$1,286,079.02
Less MF6 base	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)
Total Deferral	$1,194,777.68	$1,369,436.33	$1,264,895.44	$1,124,751.40	$1,064,007.66	$747,730.01	$795,353.27	$725,010.52	$767,246.44	$921,489.35
Cumulative Deferral	$1,194,777.68	$2,569,896.17	$3,846,986.58	$4,990,060.77	$6,077,800.33	$6,854,435.35	$7,682,387.17	$8,443,933.84	$9,251,338.22	$10,216,825.39
Carrying Costs (1)	$5,682.16	$12,194.97	$18,322.79	$23,731.90	$28,905.01	$32,598.55	$36,536.15	$40,157.94	$43,997.82	$48,589.52
Cumulative Deferral with carrying costs	$1,200,459.84	$2,582,091.14	$3,865,309.37	$5,013,792.67	$6,106,705.34	$6,887,033.90	$7,718,923.32	$8,484,091.78	$9,295,336.04	$10,265,414.91

Duke Energy Kentucky, Inc.
East Bend Deferral Analysis

DEK East Bend Deferral Forecast	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16
O&M	$747,881.01	$1,274,276.91	$451,395.18	$915,243.70	$1,383,284.41	$3,067,186.11	$760,341.40	$828,785.28	$529,828.26	$707,425.06
Reagents EB Incremental	$287,362.50	$227,097.70	$284,029.00	$270,017.30	$226,066.00	$7,412.60	$169,194.40	$293,808.30	$304,607.30	$363,747.20
Total Incremental	$1,035,243.51	$1,501,374.61	$735,424.18	$1,185,261.00	$1,609,350.41	$3,074,598.71	$929,535.80	$1,122,594.58	$834,435.56	$1,071,172.26
Less MF6 base	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)
Total Deferral	$670,653.84	$1,136,784.94	$370,834.51	$820,671.33	$1,244,760.74	$2,710,009.04	$564,946.13	$758,004.91	$469,845.89	$706,582.59
Cumulative Deferral	$10,936,068.75	$12,124,853.61	$12,553,362.15	$13,433,735.18	$14,742,384.53	$17,522,505.89	$18,170,786.14	$19,015,208.28	$19,575,487.33	$20,375,167.67
Carrying Costs (1)	$52,010.12	$57,663.83	$59,701.70	$63,888.61	$70,112.32	$83,334.12	$86,417.23	$90,433.16	$93,097.75	$96,900.90
Cumulative Deferral with carrying costs	$10,988,078.87	$12,182,527.64	$12,613,063.85	$13,497,623.79	$14,812,496.85	$17,605,840.01	$18,257,203.37	$19,105,641.44	$19,668,585.08	$20,472,068.57

Duke Energy Kentucky, Inc
East Bend Deferral Analysis

DEK East Bend Deferral Forecast	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17
O&M	$676,473.97	$454,622.11	$601,413.21	$1,018,179.69	$1,150,935.73	$1,150,935.73	$1,150,935.73	$1,150,935.73	$1,150,935.73	$1,150,935.73
Reagents EB Incremental	$343,534.50	$354,215.00	$325,529.30	$253,948.90	$158,333.33	$158,333.33	$158,333.33	$158,333.33	$158,333.33	$158,333.33
Total Incremental	$1,020,008.47	$808,837.11	$926,942.51	$1,272,128.59	$1,309,269.06	$1,309,269.06	$1,309,269.06	$1,309,269.06	$1,309,269.06	$1,309,269.06
Less MF6 base	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)
Total Deferral	$655,418.80	$444,247.44	$562,352.84	$907,538.92	$944,679.39	$944,679.39	$944,679.39	$944,679.39	$944,679.39	$944,679.39
Cumulative Deferral	$21,127,487.37	$21,672,213.62	$22,337,635.89	$23,351,408.88	$24,407,143.68	$25,465,653.01	$26,528,925.75	$27,597,243.92	$28,670,630.83	$29,749,110.54
Carrying Costs (1)	$100,478.81	$103,069.43	$106,234.07	$111,055.41	$113,829.94	$118,593.35	$123,638.78	$128,707.52	$133,800.32	$138,917.28
Cumulative Deferral with carrying costs	$21,227,966.18	$21,775,283.05	$22,443,869.96	$23,462,464.29	$24,520,973.62	$25,584,246.36	$26,652,564.53	$27,725,951.44	$28,804,431.15	$29,888,027.81

Duke Energy Kentucky, Inc.
East Bend Deferral Analysis

DEK East Bend Deferral Forecast	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18
O&M	$1,150,935.73	$1,150,935.73	$1,150,935.73	$1,150,935.73	$1,150,935.73	$1,150,935.73	$1,150,935.73	$1,150,935.73	$1,150,935.73
Reagents EB Incremental	$158,333.33	$158,333.33	$158,333.33	$158,333.33	$158,333.33	$158,333.33	$158,333.33	$158,333.33	$158,333.33
Total Incremental	$1,309,269.06	$1,309,269.06	$1,309,269.06	$1,309,269.06	$1,309,269.06	$1,309,269.06	$1,309,269.06	$1,309,269.06	$1,309,269.06
Less MF6 base	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.67)	($364,589.57)	($364,589.67)
Total Deferral	$944,679.39	$944,679.39	$944,679.39	$944,679.39	$944,679.39	$944,679.39	$944,679.39	$944,679.39	$944,679.39
Cumulative Deferral	$30,832,707.20	$31,921,445.11	$33,015,348.64	$34,114,442.32	$35,218,750.75	$36,328,298.70	$37,272,978.09	$38,217,657.48	$39,162,336.87
Carrying Costs (1)	$144,058.51	$149,224.14	$154,414.28	$159,629.05	$164,868.56	$170,132.92	$175,017.70	$179,510.44	$184,003.18
Cumulative Deferral with carrying costs	$30,976,765.72	$32,070,669.25	$33,169,762.93	$34,274,071.36	$35,383,619.31	$36,503,316.40	$37,452,488.53	$38,401,660.66	$39,162,336.87

EXHIBIT ____ (LK-14)

Duke Energy Kentucky
Case No. 2017-00321
Attorney General's First Set Data Requests
Date Received: October 27, 2017

AG-DR-01-034

REQUEST:

Provide a copy of the depreciation study(ies) underlying the current depreciation rates and cite all cases in which those rates were authorized. If not indicated in the depreciation study(ies), provide the terminal net salvage component of the depreciation rates and the underlying workpapers support, including any conceptual or other studies used to develop the terminal net salvage estimate and/or percentage. If not indicated in the depreciation study(ies), provide the probable retirement date and service life used for each unit in the study(ies).

RESPONSE:

The attached schedule, AG-DR-01-034(a) Attachment, sets forth the current depreciation rates, probable retirement date, life and salvage parameters utilized to develop those depreciation rates. The depreciation rates were developed and authorized in Case No. 2006-00172. The terminal net salvage component approved in Case No. 2006-00172 is set forth in the net salvage percent utilized in the depreciation rate. These workpapers are set forth in AG-DR-01-034(b) Attachment.

PERSON RESPONSIBLE: John J. Spanos

DUKE ENERGY KENTUCKY

CURRENT RETIREMENT DATES, SURVIVOR CURVES, NET SALVAGE, AND ANNUAL DEPRECIATION RATES

	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE		NET SALVAGE PERCENT	CURRENT DEPRECIATION RATE
	(1)	(2)	(3)		(4)	(5)
	COMMON PLANT					
1900	STRUCTURES & IMPROVEMENTS					
	ERLANGER OPERATIONS CENTER		15-SQ		0	6.78
	FLORENCE SERVICE BUILDING	06-2041	100-R1	*	(10)	2.54
	KENTUCKY SERVICE BUILDING - 19TH & AUGUSTINE	06-2012	100-R1	*	(10)	5.94
	MINOR STRUCTURES		40-R1		0	3.20
1910	OFFICE FURNITURE AND EQUIPMENT		20-SQ		0	12.36
1930	STORES AND EQUIPMENT		20-SQ		0	48.47
1940	TOOLS, SHOP AND GARAGE EQUIPMENT		25-SQ		0	6.27
1970	COMMUNICATION EQUIPMENT		15-SQ		0	13.62
1980	MISCELLANEOUS EQUIPMENT		15-SQ		0	6.65
	STEAM PRODUCTION PLANT					
	MIAMI FORT UNIT 6					
3110	STRUCTURES AND IMPROVEMENTS	06-2020	100-R2.5	*	(4)	0.28
3120	BOILER PLANT	06-2020	55-S1	*	(13)	5.35
3122	BOILER PLANT - RETROFIT PRECIPITATORS	06-2020	50-S1.5	*	(12)	1.24
3140	TURBOGENERATOR UNITS	06-2020	55-R2.5	*	(9)	1.16
3150	ACCESSORY ELECTRIC EQUIPMENT	06-2020	60-R2.5	*	(4)	1.13
3160	MISCELLANEOUS POWER PLANT - EXCLUDING SHOP	06-2020	55-S0.5	*	0	5.53
	EAST BEND					
3110	STRUCTURES AND IMPROVEMENTS	06-2041	100-R2.5	*	(3)	1.28
3120	BOILER PLANT	06-2041	55-S1	*	(11)	2.32
3123	BOILER PLANT - CATALYST		8-S2.5		0	15.28
3140	TURBOGENERATOR UNITS	06-2041	55-R2.5	*	(8)	2.26
3150	ACCESSORY ELECTRIC EQUIPMENT	06-2041	60-R2.5	*	(4)	1.72
3160	MISCELLANEOUS POWER PLANT - EXCLUDING SHOP	06-2041	55-S0.5	*	0	2.15
	OTHER PRODUCTION PLANT					
3401	RIGHTS OF WAY		40-SQ		0	3.63
3410	STRUCTURES AND IMPROVEMENTS	06-2032	SQUARE	*	(3)	2.04
3420	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2032	SQUARE	*	(3)	1.75
3430	PRIME MOVERS	06-2032	SQUARE	*	(5)	3.96
3440	GENERATORS	06-2032	75-R2.5	*	(4)	2.38
3450	ACCESSORY ELECTRIC EQUIPMENT	06-2032	55-S2	*	0	1.80
3460	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2032	50-R2.5	*	0	2.00
	TRANSMISSION PLANT					
3501	RIGHTS OF WAY		65-R4		0	1.48
3520	STRUCTURES AND IMPROVEMENTS		55-R3		(5)	0.41
3530	STATION EQUIPMENT		50-R1.5		(5)	2.25
3532	STATION EQUIPMENT - MAJOR		50-R3		(10)	2.27
3535	STATION EQUIPMENT - ELECTRONIC		15-R2		0	9.55
3550	POLES AND FIXTURES		50-R1.5		(20)	2.10
3560	OVERHEAD CONDUCTORS AND DEVICES		44-R0.5		(10)	2.31

DUKE ENERGY KENTUCKY

CURRENT RETIREMENT DATES, SURVIVOR CURVES, NET SALVAGE, AND ANNUAL DEPRECIATION RATES

	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	CURRENT DEPRECIATION RATE
	(1)	(2)	(3)	(4)	(5)
	DISTRIBUTION PLANT				
3601	RIGHTS OF WAY		70-R3	0	1.07
3610	STRUCTURES AND IMPROVEMENTS		55-R3	(5)	0.94
3620	STATION EQUIPMENT		50-R2	(10)	2.91
3622	STATION EQUIPMENT - MAJOR		50-R3	(10)	2.77
3635	STATION EQUIPMENT - ELECTRONIC		15-R2	0	9.65
3640	POLES, TOWERS AND FIXTURES		44-R0.5	(15)	3.29
3650	OVERHEAD CONDUCTORS AND DEVICES		46-R1.5	(20)	2.46
3660	UNDERGROUND CONDUIT		65-R3	(15)	2.00
3670	UNDERGROUND CONDUCTORS AND DEVICES		65-R3	(25)	2.29
3680	LINE TRANSFORMERS		38-R1.5	0	2.42
3682	LINE TRANSFORMERS - CUSTOMER		50-R1.5	0	-
3691	SERVICES - UNDERGROUND		55-R2	(25)	2.73
3692	SERVICES - OVERHEAD		50-R1	(50)	2.45
3700	METERS		28-S0	0	5.82
3701	LEASED METERS		28-S0	0	5.61
3720	LEASED PROPERTY ON CUSTOMER PREMISES		25-L2	0	-
3731	STREET LIGHTING - OVERHEAD		30-L1	(5)	0.92
3732	STREET LIGHTING - BOULEVARD		30-L1	(5)	3.62
3733	STREET LIGHTING - CUSTOMER POLES		33-R1.5	(15)	1.47
	GENERAL PLANT				
3900	STRUCTURES AND IMPROVEMENTS		35-R2.5	(5)	1.77
3910	OFFICE FURNITURE AND EQUIPMENT		20-SQ	0	18.56
3921	TRAILERS		15-SQ	0	6.53
3940	TOOLS, SHOP AND GARAGE EQUIPMENT		25-SQ	0	4.14
3960	POWER OPERATED EQUIPMENT		14-R3	0	-
3970	COMMUNICATION EQUIPMENT		15-SQ	0	6.93

* CURVE SHOWN IS INTERIM SURVIVOR CURVE. EACH FACILITY IN THE ACCOUNT IS ASSIGNED AN INDIVIDUAL PROBABLE RETIREMENT YEAR.

DUKE ENERGY KENTUCKY
DETERMINATION OF NET SALVAGE PERCENTS AFTER ESCALATED DECOMMISSIONING COSTS

	ACCOUNT (1)	NET SALVAGE PERCENT (2)	ORIGINAL COST (3)	ORIGINAL COST SURVIVING AT RETIREMENT DATE (4)	ALLOCATION AMOUNT (5)	ESCALATED DECOMMISSIONING COST (6)	DECOMMISSIONING ALLOCATION AMOUNT (7)=(6)*(5)	INTERIM NET SALVAGE (8)=[(3)-(4)]*(2)	NEW SALVAGE ESTIMATE (9)=[(7)+(8)]/(3)
	EAST BEND UNITS 1 & 2								
3110	STRUCTURES AND IMPROVEMENTS	(5)	35,078,476.47	31,570,628.82	(1,753,923.82)		(992,215.93)	(175,392.38)	(3)
3120	BOILER PLANT	(15)	276,530,868.48	221,224,693.18	(41,479,629.97)		(23,465,528.67)	(8,295,926.00)	(11)
3122	BOILER PLANT - RETROFIT PRECIPITATORS	(15)	0.00	0.00	0.00		0.00	0.00	
3140	TURBOGENERATOR UNITS	(10)	66,989,482.81	53,591,586.25	(6,698,948.28)		(3,789,676.11)	(1,339,789.66)	(8)
3150	ACCESSORY ELECTRIC EQUIPMENT	(5)	25,101,925.75	17,571,348.03	(1,255,096.29)		(710,023.16)	(376,528.89)	(4)
3160	MISCELLANEOUS POWER PLANT	0	8,496,040.20	6,372,030.15	0.00		0.00	0.00	0
					(51,187,598.36)	(28,957,443.87) **	(28,957,443.87)		
	MIAMI FORT UNIT 6								
3110	STRUCTURES AND IMPROVEMENTS	(5)	3,056,616.76	2,139,631.73	(152,830.84)		(73,588.58)	(45,849.25)	(4)
3120	BOILER PLANT	(15)	37,142,775.96	22,285,665.58	(5,571,416.39)		(2,682,656.40)	(2,228,566.56)	(13)
3122	BOILER PLANT - RETROFIT PRECIPITATORS	(15)	11,772,653.72	7,652,224.92	(1,765,898.06)		(850,286.07)	(618,064.32)	(12)
3123	BOILER PLANT - SCRUBBERS	(15)	0.00	0.00	0.00		0.00	0.00	
3140	TURBOGENERATOR UNITS	(10)	11,501,258.65	6,900,755.19	(1,150,125.87)		(553,789.61)	(460,050.35)	(9)
3150	ACCESSORY ELECTRIC EQUIPMENT	(5)	4,075,296.48	2,648,942.71	(203,764.82)		(98,113.47)	(71,317.69)	(4)
3160	MISCELLANEOUS POWER PLANT - EXCLUDING SHOP	0	724,421.07	543,315.80	0.00		0.00	0.00	0
					(8,844,035.98)	(4,258,434.13) **	(4,258,434.13)		
	WOODSDALE UNITS 1 THROUGH 6								
3410	STRUCTURES AND IMPROVEMENTS	(5)	33,725,782.31	33,725,782.31	(1,686,289.12)		(908,148.66)	0.00	(3)
3420	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	(5)	15,507,515.98	15,507,515.98	(775,375.80)		(417,577.56)	0.00	(3)
3430	PRIME MOVERS	(10)	173,729.17	173,729.17	(17,372.92)		(9,356.16)	0.00	(5)
3440	GENERATORS	(5)	188,960,592.35	141,720,444.26	(9,448,029.62)		(5,088,223.21)	(2,362,007.40)	(4)
3450	ACCESSORY ELECTRIC EQUIPMENT	0	16,867,009.87	11,806,906.91	0.00		0.00	0.00	0
3460	MISCELLANEOUS POWER PLANT EQUIPMENT	0	3,701,280.07	2,590,896.05	0.00		0.00	0.00	0
					(11,927,067.46)	(6,423,305.59)	(6,423,305.59)		

** EXCLUDES ASBESTOS REMOVAL AND INCLUDES SCRAP VALUE

EXHIBIT ____ (LK-15)

AG-DR-01-035

REQUEST:

Provide all depreciation rate calculations using the Average Life Group (ALG) methodology instead of the Equal Life Group ("ELG") methodology. Provide this information in hard copy and in electronic format (Excel) with all formulas intact.

RESPONSE:

The attached schedule, AG-DR-01-035(a) Attachment, and the detailed calculations, AG-DR-01-035(b) Attachment, set forth the requested information in the available electronic format.

PERSON RESPONSIBLE: John J. Spanos

DUKE ENERGY KENTUCKY
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2016

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	COMMON PLANT								
1900	STRUCTURES AND IMPROVEMENTS								
	ERLANGER OPERATIONS CENTER	90-R1 *	0	5,938,868.27	3,425,912	2,512,956	57,590	0.97	43.6
	KENTUCKY SERVICE BUILDING - 19TH AND AUGUSTINE	90-R1 *	0	1,798,785.05	1,618,907	179,879	7,430	0.41	24.2
	MINOR STRUCTURES	40-R1	(10)	3,671,283.62	1,141,603	2,896,809	78,568	2.14	36.9
	TOTAL STRUCTURES AND IMPROVEMENTS			11,408,936.94	6,186,422	5,589,644	143,588	1.26	38.9
1910	OFFICE FURNITURE AND EQUIPMENT	20-SQ	0	67,899.49	10,094	57,805	3,398	5.00	17.0
1911	ELECTRONIC DATA PROCESSING	5-SQ	0	807,216.83	545,610	261,607	161,473	20.00	1.6
1940	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SO	0	127,323.71	46,888	80,436	5,087	4.00	15.8
1970	COMMUNICATION EQUIPMENT	15-SQ	0	7,755,234.45	3,827,968	3,927,266	517,384	6.67	7.6
1980	MISCELLANEOUS EQUIPMENT	15-SO	0	41,504.01	15,956	25,548	2,770	6.67	9.2
	TOTAL COMMON PLANT			**20,208,115.43**	**10,632,939**	**9,942,306**	**833,700**	**4.13**	**11.9**
	STEAM PRODUCTION PLANT								
3110	STRUCTURES AND IMPROVEMENTS	100-S0.5 *	(17)	71,372,344.69	41,147,398	42,358,246	1,761,884	2.47	24.0
3120	BOILER PLANT EQUIPMENT	40-S0.5 *	(17)	453,023,974.40	305,620,093	224,417,957	10,156,202	2.24	22.1
3123	BOILER PLANT EQUIPMENT - SCR CATALYST	10-S2.5	0	5,420,680.46	3,370,330	2,050,350	247,333	4.56	8.3
3140	TURBOGENERATOR UNITS	40-S0.5 *	(17)	100,695,783.40	66,465,609	51,348,458	2,373,174	2.36	21.6
3150	ACCESSORY ELECTRIC EQUIPMENT	55-R2 *	(17)	44,736,780.67	29,260,579	23,081,454	1,003,384	2.24	23.0
3160	MISCELLANEOUS POWER PLANT EQUIPMENT	45-S0 *	(17)	19,377,682.01	9,282,060	13,389,828	613,593	3.17	21.8
	TOTAL STEAM PRODUCTION PLANT			**694,627,245.63**	**455,146,070**	**356,646,293**	**16,155,570**	**2.33**	**22.1**
	OTHER PRODUCTION PLANT								
3401	RIGHTS OF WAY	40-SO	0	651,684.00	271,137	380,547	24,551	3.77	15.5
3410	STRUCTURES AND IMPROVEMENTS	60-R4 *	(4)	36,133,374.66	23,762,723	13,815,986	909,196	2.52	15.2
3420	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	55-S2.5 *	(4)	15,785,782.40	11,489,834	4,927,380	336,020	2.13	14.7
3440	GENERATORS	45-R2 *	(4)	210,038,948.92	117,476,601	100,963,906	7,065,233	3.36	14.3
3450	ACCESSORY ELECTRIC EQUIPMENT	40-R2 *	(4)	21,372,936.35	10,850,111	11,377,743	817,292	3.82	13.9
3460	MISCELLANEOUS POWER PLANT EQUIPMENT	35-S0 *	(4)	4,671,828.67	2,562,803	2,295,899	173,281	3.71	13.2
	TOTAL OTHER PRODUCTION PLANT			**288,654,555.00**	**166,413,209**	**133,761,461**	**9,325,573**	**3.23**	**14.3**
	TRANSMISSION PLANT								
3501	RIGHTS OF WAY	65-R4	0	1,092,199.49	644,167	448,033	13,922	1.27	32.2
3520	STRUCTURES AND IMPROVEMENTS	65-R2.5	(10)	1,480,413.30	241,283	1,387,172	28,998	1.96	47.8
3530	STATION EQUIPMENT	50-R2	(15)	16,703,413.69	4,556,595	14,652,330	360,750	2.16	40.6
3531	STATION EQUIPMENT - STEP UP	50-R2.5	0	9,373,633.98	3,842,564	5,531,070	192,366	2.05	28.8
3532	STATION EQUIPMENT - MAJOR	60-R2.5	(10)	5,965,587.37	1,738,102	4,824,044	102,921	1.73	46.9
3534	STATION EQUIPMENT - STEP UP EQUIPMENT	30-R2.5	0	7,057,290.24	802,521	6,254,769	291,558	4.13	21.5
3550	POLES AND FIXTURES	55-R1.5	(30)	7,565,364.06	4,009,740	5,825,234	133,233	1.76	43.7
3560	OVERHEAD CONDUCTORS AND DEVICES	50-R1	(30)	5,791,808.11	3,469,281	4,040,069	110,887	1.91	36.5
3561	OVERHEAD CONDUCTORS AND DEVICES - CLEARING/ROW	60-R3	0	213,241.32	2,117	211,124	3,714	1.74	56.8
	TOTAL TRANSMISSION PLANT			**55,242,951.56**	**19,326,370**	**43,173,845**	**1,238,149**	**2.24**	**34.9**

DUKE ENERGY KENTUCKY
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2016

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	DISTRIBUTION PLANT								
3601	RIGHTS OF WAY	70-R3	0	6,439,899.15	2,942,255	3,497,644	66,306	1.03	52.8
3610	STRUCTURES AND IMPROVEMENTS	65-R2.5	(10)	1,470,232.87	53,521	1,563,735	33,254	2.26	47.0
3620	STATION EQUIPMENT	48-R2.5	(15)	36,917,375.12	10,841,330	31,613,651	866,413	2.35	36.5
3622	STATION EQUIPMENT - MAJOR	60-R2.5	(10)	25,253,260.24	9,088,622	18,689,964	402,515	1.59	46.4
3640	POLES, TOWERS AND FIXTURES	52-R0.5	(40)	56,105,078.63	28,096,369	50,448,742	1,170,250	2.09	43.1
3650	OVERHEAD CONDUCTORS AND DEVICES	50-O1	(25)	116,901,323.62	36,628,887	109,497,767	2,496,981	2.14	43.9
3651	OVERHEAD CONDUCTORS AND DEVICES - CLEARING/ROW	60-R2.5	0	1,827,217.70	103,637	1,723,581	30,137	1.65	57.2
3660	UNDERGROUND CONDUIT	65-S2.5	(20)	18,863,541.33	6,147,852	16,488,398	340,210	1.80	48.5
3670	UNDERGROUND CONDUCTORS AND DEVICES	58-R2	(20)	58,304,068.59	15,449,020	54,515,862	1,209,793	2.07	45.1
3680	LINE TRANSFORMERS	45-R0.5	(10)	55,611,324.10	28,319,252	32,853,205	933,420	1.68	35.2
3682	LINE TRANSFORMERS - CUSTOMER	50-R1.5	(10)	273,660.52	279,531	21,495	857	0.31	25.1
3691	SERVICES - UNDERGROUND	60-R2	(25)	2,393,706.08	460,181	2,531,952	44,728	1.87	56.6
3692	SERVICES - OVERHEAD	53-R1	(20)	15,729,900.78	10,007,160	8,868,721	180,957	1.21	46.4
3700	METERS	24-L1	(1)	12,211,085.54	3,303,526	9,029,670	771,814	6.32	
3701	INSTRUMENTATION TRANSFORMERS	24-L1	(1)	714,995.08	261,903	460,242	72,718	10.17	6.3
3702	UoF METERS	15-S2.5	0	395,724.90	9,493	386,232	27,091	6.85	14.3
3712	COMPANY-OWNED OUTDOOR LIGHTING	20-S0.5	0	409,941.97	15,094	394,848	21,547	5.26	18.3
3720	LEASED PROPERTY ON CUSTOMER PREMISES	25-L3	0	9,647.36	9,647	0	0	-	-
3731	STREET LIGHTING - OVERHEAD	32-L0.5	(10)	2,739,571.44	2,435,218	578,311	19,886	0.73	29.1
3732	STREET LIGHTING - BOULEVARD	45-R1.5	(10)	3,358,776.28	2,373,606	1,321,048	39,546	1.18	33.4
3733	STREET LIGHTING - CUSTOMER POLES	30-L0	(10)	3,874,765.33	1,484,538	2,777,704	103,399	2.67	26.9
	TOTAL DISTRIBUTION PLANT			**419,805,096.83**	**158,312,844**	**347,262,772**	**8,841,822**	**2.11**	**39.3**
	GENERAL PLANT								
3900	STRUCTURES AND IMPROVEMENTS	35-S1	(5)	144,963.75	43,841	108,392	4,923	3.40	22.0
3910	OFFICE FURNITURE AND EQUIPMENT	20-SQ	0	15,317.31	15,317	0	0	-	-
3911	ELECTRONIC DATA PROCESSING	5-SQ	0	2,369,951.38	1,163,228	1,206,723	474,050	20.00	2.5
3920	TRANSPORTATION EQUIPMENT	12-S3	0	218,719.32	3,363	215,356	18,727	8.56	11.5
3921	TRANSPORTATION EQUIPMENT - TRAILERS	18-R2.5	5	201,059.78	116,402	74,605	7,718	3.84	9.7
3940	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	0	2,027,306.34	458,617	1,568,690	81,146	4.00	19.3
3960	POWER OPERATED EQUIPMENT	15-L2	0	11,770.00	5,449	6,321	793	6.74	8.0
3970	COMMUNICATION EQUIPMENT	15-SQ	0	2,882,947.32	1,090,984	1,791,963	192,305	6.67	9.3
	TOTAL GENERAL PLANT			**7,872,055.20**	**2,897,202**	**4,972,050**	**779,662**	**9.90**	**6.4**
	UNRECOVERED RESERVE FOR AMORTIZATION								
	COMMON PLANT								
1910	OFFICE FURNITURE AND EQUIPMENT				550		(110)		
1911	ELECTRONIC DATA PROCESSING				(57,600)		11,520		
1940	TOOLS, SHOP AND GARAGE EQUIPMENT				18,000		(3,600)		
1970	COMMUNICATION EQUIPMENT				3,766,000		(753,200)		
1980	MISCELLANEOUS EQUIPMENT				(4,300)		860		
	TOTAL COMMON PLANT				**3,722,650**		**(744,530)**		

DUKE ENERGY KENTUCKY
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2016

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	ELECTRIC PLANT								
3910	OFFICE FURNITURE AND EQUIPMENT				1,254		(251)		
3911	ELECTRONIC DATA PROCESSING				242,000		(48,400)		
3940	TOOLS, SHOP AND GARAGE EQUIPMENT				(43,000)		8,600		
3970	COMMUNICATION EQUIPMENT				75,000		(15,000)		
	TOTAL ELECTRIC PLANT				275,254		(55,051)		
	TOTAL UNRECOVERED RESERVE FOR AMORTIZATION				3,997,904		(799,681)		
	TOTAL DEPRECIABLE PLANT			1,486,410,019.66	816,726,338	895,758,727	36,374,895	2.45	
	NONDEPRECIABLE PLANT								
1890	LAND			154,248.18					
3100	LAND			7,047,300.74	60,798				
3170	ARO			46,586,238.12	7,017,696				
3400	LAND			2,258,588.39					
3500	LAND			249,216.68					
3600	LAND			6,830,709.67					
	TOTAL NONDEPRECIABLE PLANT			63,126,301.78	7,078,494				
	ACCOUNTS NOT STUDIED								
1030	MISCELLANEOUS INTANGIBLE PLANT			22,332,072.52	22,232,108				
3030	MISCELLANEOUS INTANGIBLE PLANT			12,089,205.48	7,524,770				
3030	MISCELLANEOUS INTANGIBLE PLANT - MIAMI FORT UNIT 6			254,010.81	154,057				
	TOTAL ACCOUNTS NOT STUDIED			34,675,288.81	29,910,935				
	TOTAL COMMON AND ELECTRIC PLANT			1,584,211,610.24	853,715,767	895,758,727	36,374,895		

* CURVE SHOWN IS INTERIM SURVIVOR CURVE. EACH FACILITY IN THE ACCOUNT IS ASSIGNED AN INDIVIDUAL PROBABLE RETIREMENT YEAR.
** REMAINING RATE BASE AMORTIZED OVER 15 YEARS.

NOTE: ACCRUAL RATES AS OF DECEMBER 31, 2017 FOR NEW SOLAR FACILITY WILL BE AS FOLLOWS

ACCOUNT	RATE
341	4.13
344	5.11
345	4.93

EXHIBIT ____ (LK-16)

Duke Energy Kentucky
Case No. 2017-00321
Attorney General's First Set Data Requests
Date Received: October 27, 2017

AG-DR-01-036

REQUEST:

Provide a schedule that shows current versus proposed depreciation rates in the same format as the Gannett Fleming Depreciation Study Table 1.

RESPONSE:

The attached schedule, AG-DR-01-036 Attachment, sets forth a comparison of the current versus proposed depreciation rates.

PERSON RESPONSIBLE: John J. Spanos

DUKE ENERGY KENTUCKY

PROPOSED AND EXISTING DEPRECIATION ACCRUAL RATES
RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2016

	ACCOUNT (1)	CURRENT RATE (2)	PROPOSED RATE (3)
	COMMON PLANT		
1900	STRUCTURES AND IMPROVEMENTS		
	ERLANGER OPERATIONS CENTER	6.78	1.28
	KENTUCKY SERVICE BUILDING - 19TH AND AUGUSTINE	5.94	0.43
	MINOR STRUCTURES	3.20	2.81
1910	OFFICE FURNITURE AND EQUIPMENT	12.36	5.00
1911	ELECTRONIC DATA PROCESSING	-	20.00
1940	TOOLS, SHOP AND GARAGE EQUIPMENT	6.27	4.00
1970	COMMUNICATION EQUIPMENT	13.62	6.67
1980	MISCELLANEOUS EQUIPMENT	6.65	6.67
	STEAM PRODUCTION PLANT		
3110	STRUCTURES AND IMPROVEMENTS	1.28	2.54
3120	BOILER PLANT EQUIPMENT	2.32	2.54
3123	BOILER PLANT EQUIPMENT - SCR CATALYST	15.28	5.13
3140	TURBOGENERATOR UNITS	2.26	2.66
3150	ACCESSORY ELECTRIC EQUIPMENT	1.72	2.43
3160	MISCELLANEOUS POWER PLANT EQUIPMENT	2.15	3.64
	OTHER PRODUCTION PLANT		
3401	RIGHTS OF WAY	3.63	3.77
3410	STRUCTURES AND IMPROVEMENTS	2.04	2.53
3420	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	1.75	2.17
3440	GENERATORS	2.38	3.48
3450	ACCESSORY ELECTRIC EQUIPMENT	1.80	4.03
3460	MISCELLANEOUS POWER PLANT EQUIPMENT	2.00	4.01
	TRANSMISSION PLANT		
3501	RIGHTS OF WAY	1.48	1.39
3520	STRUCTURES AND IMPROVEMENTS	0.41	2.35
3530	STATION EQUIPMENT	2.25	2.79
3531	STATION EQUIPMENT - STEP UP	-	2.36
3532	STATION EQUIPMENT - MAJOR	2.27	2.10
3534	STATION EQUIPMENT - STEP UP EQUIPMENT	-	4.90
3550	POLES AND FIXTURES	2.10	2.39
3560	OVERHEAD CONDUCTORS AND DEVICES	2.31	2.58
3561	OVERHEAD CONDUCTORS AND DEVICES - CLEARING/ROW	-	2.03

DUKE ENERGY KENTUCKY

PROPOSED AND EXISTING DEPRECIATION ACCRUAL RATES
RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2016

	ACCOUNT (1)	CURRENT RATE (2)	PROPOSED RATE (3)
	DISTRIBUTION PLANT		
3601	RIGHTS OF WAY	1.07	1.18
3610	STRUCTURES AND IMPROVEMENTS	0.94	2.74
3620	STATION EQUIPMENT	2.91	2.85
3622	STATION EQUIPMENT - MAJOR	2.77	1.92
3640	POLES, TOWERS AND FIXTURES	3.29	3.26
3650	OVERHEAD CONDUCTORS AND DEVICES	2.46	3.56
3651	OVERHEAD CONDUCTORS AND DEVICES - CLEARING/ROW	-	2.10
3660	UNDERGROUND CONDUIT	2.00	2.04
3670	UNDERGROUND CONDUCTORS AND DEVICES	2.29	2.62
3680	LINE TRANSFORMERS	2.42	2.49
3682	LINE TRANSFORMERS - CUSTOMER	2.00	0.38
3691	SERVICES - UNDERGROUND	2.73	2.54
3692	SERVICES - OVERHEAD	2.45	1.87
3700	METERS	5.82	6.32
3701	INSTRUMENTATION TRANSFORMERS	-	11.21
3702	UoF METERS	-	7.60
3712	COMPANY-OWNED OUTDOOR LIGHTING	-	7.36
3720	LEASED PROPERTY ON CUSTOMER PREMISES	-	-
3731	STREET LIGHTING - OVERHEAD	0.92	1.22
3732	STREET LIGHTING - BOULEVARD	3.62	1.49
3733	STREET LIGHTING - CUSTOMER POLES	1.47	4.88
	GENERAL PLANT		
3900	STRUCTURES AND IMPROVEMENTS	1.77	5.36
3910	OFFICE FURNITURE AND EQUIPMENT	18.56	-
3911	ELECTRONIC DATA PROCESSING	-	20.00
3920	TRANSPORTATION EQUIPMENT	-	9.23
3921	TRANSPORTATION EQUIPMENT - TRAILERS	6.53	4.50
3940	TOOLS, SHOP AND GARAGE EQUIPMENT	4.14	4.00
3960	POWER OPERATED EQUIPMENT	-	8.62
3970	COMMUNICATION EQUIPMENT	6.93	6.67

EXHIBIT ____ (LK-17)

AG-DR-01-039

REQUEST:

Provide a schedule and electronic spreadsheet in live format with all formulas intact showing the additional depreciation expense in the test year due to the proposed change in depreciation rates. In addition, on this same schedule, provide the related increase in accumulated depreciation and reduction in ADIT.

RESPONSE:

Please see AG-DR-01-039 Attachment provided on CD. For comparison to the proposed rates from Sch B-3.2, accounts are summarized by functional class.

PERSON RESPONSIBLE: Cynthia S. Lee

Functional Class	Annual Expense Proposed Rates	Test Period Expense Current Rates	Accum Depreciation Increase/(Decrease)	ADIT Increase/(Decrease)
Steam Production	20,334,546	15,029,467	5,305,079	(2,040,864)
Other Production	11,297,071	10,628,770	668,301	(257,095)
Transmission	1,829,174	1,353,444	475,730	(183,013)
Distribution	14,391,125	12,079,746	2,311,379	(889,187)
General	2,845,247	5,450,835	(2,605,588)	1,002,370
Common	(218,467)	-	(218,467)	84,044
Total	**50,478,696**	**44,542,262**	**5,936,434**	**(2,283,746)**
	ties to Sch B-3.2	ties to Sch C-2.1	ties to Sch D-2.24	

EXHIBIT ____ (LK-18)

Duke Energy Kentucky
Case No. 2017-00321
Attorney General's First Set Data Requests
Date Received: October 27, 2017

AG-DR-01-037

REQUEST:

Refer to Schedule V-III-4 of the Gannett Fleming Depreciation Study which shows the escalation of the 2016 based Burns McDonnell Decommissioning estimates to future values. Provide the rate of escalation assumed in these calculations and explain why that rate is appropriate.

RESPONSE:

An escalation factor of 2.5% was used to determine the future values shown in Table 3 (page VIII-4 of Depreciation Study). The decommissioning costs established in the Burns & McDonnell study were reported in 2016 dollars. Since the units will not be retired until 2032 and 2041, it is appropriate to escalate the decommissioning costs annually to the date of retirement. This is a commonly utilized escalation which is based on widely accepted measures of inflation such as the Consumer Price Index and the Handy Whitman Index.

PERSON RESPONSIBLE: John J. Spanos

EXHIBIT ____ (LK-19)

AG-DR-02-005

REQUEST:

Provide the general business credit for increasing research activities actually reflected on the standalone DEK federal income tax returns for each year 2012 through 2016, forecasted for 2017, 2018, and 2019, forecast for the test year, all on a total Company, electric, and gas basis, and provide the credit reflected in the calculation of income tax expense in the test year revenue requirement. If the Company did not or does not budget and/or forecast this credit, then so state and explain why it does not do so.

RESPONSE:

See AG-DR-02-005 Attachment being uploaded electronically and a copy provided on CD.

PERSON RESPONSIBLE: Lisa Bellucci

General Business Credit for Increasing Research Activities
Standalone DEK Federal Income Tax Return

Source	Year	Total		Electric	Gas
Return	2012	67,650	(1)	67,650	
Return	2013	39,214	(1)	39,214	
Return	2014	45,843	(1)	45,843	
Return	2015	58,478	(1)	58,478	
Return	2016	477,318	(2)	225,960	251,358
Forecast	2017	85,884	(1)	85,884	
Forecast	2018	88,460	(1)	88,460	
Forecast	2019	91,114	(1)	91,114	
WPB-6	Test Year	75,727	(1), (3)	75,727	

(1) Includes EPRI Credits only.

(2) $426,031 amount relates to R&D. $51,288 amount relates to 2016 EPRI.
The true-up to the 2016 return was recorded in Q4 2017.

(3) This is the amount included in the general ledger, however it was erroneously excluded from the calculation of tax expense in the test year revenue requirement.

EXHIBIT ____ (LK-20)

Duke Energy Kentucky
Case No. 2017-00321
Attorney General's Second Set Data Requests
Date Received: November 29, 2017

AG-DR-02-009

REQUEST:

Provide separately the monthly average daily balance of cash and short-term investments (by type of investment) for each month from January 2012 through the most recent month in 2017 for which actual information is available, and each month forecasted for the remainder of 2017, calendar year 2018, and through March 2019 on a total Company basis and allocated to electric.

RESPONSE:

See AG-DR-02-009 Attachment being uploaded electronically and a copy provided on CD.

Generally speaking, when Duke Energy Kentucky has cash balances, it lends these funds into the Duke Energy Utility Moneypool. Only in certain circumstances when the utility moneypool is in a large cash surplus position does Duke Energy Kentucky invest in alternative short-term investments, such as government or Treasury money funds. This surplus situation occurred for one day in November 2017 during the period requested. At the end of November 2017, Duke Energy Kentucky was a lender into the moneypool and we expect Duke Energy Kentucky to transition from a lender into the moneypool to a borrower from the moneypool by February 2018. We expect to issue long-term debt at Duke Energy Kentucky by September 2018, which will position the utility back into a moneypool lender position.

PERSON RESPONSIBLE: John L. Sullivan

Cash and Short-Term Investments

Historical Information:

	Monthly Average Daily Balance			
	Moneypool	WF Govt Fund	Duke Energy Kentucky	Electric Allocation
Jan-12	$11,346,903	-	$11,346,903	$8,495,200
Feb-12	9,775,621	-	9,775,621	7,318,812
Mar-12	10,502,290	-	10,502,290	7,862,855
Apr-12	11,792,033	-	11,792,033	8,828,460
May-12	7,413,645	-	7,413,645	5,550,448
Jun-12	10,137,067	-	10,137,067	7,589,419
Jul-12	4,440,581	-	4,440,581	3,324,574
Aug-12	6,303,903	-	6,303,903	4,719,606
Sep-12	7,890,867	-	7,890,867	5,907,734
Oct-12	4,015,000	-	4,015,000	3,005,950
Nov-12	6,161,533	-	6,161,533	4,613,017
Dec-12	12,314,806	-	12,314,806	9,219,849
Jan-13	13,287,839	-	13,287,839	9,948,339
Feb-13	7,344,250	-	7,344,250	5,498,493
Mar-13	10,928,129	-	10,928,129	8,181,672
Apr-13	19,551,767	-	19,551,767	14,638,017
May-13	36,902,484	-	36,902,484	27,628,152
Jun-13	38,027,067	-	38,027,067	28,470,104
Jul-13	36,095,710	-	36,095,710	27,024,136
Aug-13	15,252,516	-	15,252,516	11,419,254
Sep-13	5,542,633	-	5,542,633	4,149,659
Oct-13	8,971,032	-	8,971,032	6,716,432
Nov-13	17,463,467	-	17,463,467	13,074,548
Dec-13	13,960,355	-	13,960,355	10,451,838
Jan-14	11,315,871	-	11,315,871	8,471,966
Feb-14	9,844,250	-	9,844,250	7,370,193
Mar-14	11,822,000	-	11,822,000	8,850,895
Apr-14	12,157,400	-	12,157,400	9,102,002
May-14	17,963,258	-	17,963,258	13,448,732
Jun-14	947,500	-	947,500	709,374
Jul-14	-	-	-	-
Aug-14	-	-	-	-
Sep-14	-	-	-	-
Oct-14	404,194	-	404,194	302,612
Nov-14	4,265,767	-	4,265,767	3,193,694
Dec-14	1,004,033	-	1,004,033	751,700
Jan-15	-	-	-	-
Feb-15	-	-	-	-
Mar-15	-	-	-	-
Apr-15	11,330,833	-	11,330,833	8,483,168
May-15	18,244,161	-	18,244,161	13,659,039
Jun-15	15,066,400	-	15,066,400	11,279,912
Jul-15	8,676,968	-	8,676,968	6,496,272
Aug-15	-	-	-	-
Sep-15	-	-	-	-
Oct-15	-	-	-	-
Nov-15	-	-	-	-
Dec-15	-	-	-	-
Jan-16	42,343,806	-	42,343,806	31,701,961
Feb-16	43,614,241	-	43,614,241	32,653,110
Mar-16	24,658,516	-	24,658,516	18,461,338
Apr-16	26,187,067	-	26,187,067	19,605,733
May-16	23,123,290	-	23,123,290	17,311,945
Jun-16	8,133,833	-	8,133,833	6,089,638
Jul-16	5,875,806	-	5,875,806	4,399,099
Aug-16	6,151,323	-	6,151,323	4,605,372
Sep-16	5,050,333	-	5,050,333	3,781,084
Oct-16	963,516	-	963,516	721,365
Nov-16	641,100	-	641,100	479,979
Dec-16	344,194	-	344,194	257,691
Jan-17	-	-	-	-
Feb-17	-	-	-	-
Mar-17	594,000	-	594,000	444,716
Apr-17	1,550,167	-	1,550,167	1,160,579
May-17	-	-	-	-
Jun-17	-	-	-	-
Jul-17	-	-	-	-
Aug-17	-	-	-	-
Sep-17	43,238,367	-	43,238,367	32,371,700
Oct-17	43,721,742	-	43,721,742	32,733,594
Nov-17	46,906,367	166,667	47,073,033	35,242,639

Forecasted information:

	Moneypool	WF Govt Fund	Duke Energy Kentucky	Electric Allocation
Dec-17	25,000,000	-	25,000,000	18,717,000
Jan-18	10,000,000	-	10,000,000	7,486,800
Feb-18	-	-	-	-
Mar-18	-	-	-	-
Apr-18	-	-	-	-
May-18	-	-	-	-
Jun-18	-	-	-	-
Jul-18	-	-	-	-
Aug-18	-	-	-	-
Sep-18	21,000,000	-	21,000,000	15,722,280
Oct-18	18,000,000	-	18,000,000	13,476,240
Nov-18	14,000,000	-	14,000,000	10,481,520
Dec-18	7,000,000	-	7,000,000	5,240,760
Jan-19	8,000,000	-	8,000,000	5,989,440
Feb-19	12,000,000	-	12,000,000	8,984,160
Mar-19	9,000,000	-	9,000,000	6,738,120
Apr-19	10,000,000	-	10,000,000	7,486,800
May-19	14,000,000	-	14,000,000	10,481,520
Jun-19	6,000,000	-	6,000,000	4,492,080
Jul-19	5,000,000	-	5,000,000	3,743,400
Aug-19	11,000,000	-	11,000,000	8,235,480
Sep-19	108,000,000	-	108,000,000	80,857,440
Oct-19	12,000,000	-	12,000,000	8,984,160
Nov-19	12,000,000	-	12,000,000	8,984,160
Dec-19	9,000,000	-	9,000,000	6,738,120

EXHIBIT ____ (LK-21)

AG-DR-02-004

REQUEST:

Refer to the response to AG 1-1, which provides the trial balance by month through September 2017.

a. Describe the Deferred DSM Costs in account 182401. Confirm that the DSM costs, including interest on over/under recoveries are recovered through the Company's DSM rider, not through the base revenue requirement.

b. Provide the Deferred DSM Costs for each month of the base year and the test year. Indicate whether this deferred cost was removed in some manner from the electric capitalization used to calculate the revenue requirement and deficiency in this proceeding. If not, explain why not. If so, demonstrate that it was removed.

c. Describe the Other Reg Assets - Gen Acct in account 182318.

d. Provide a schedule showing the balance of each regulatory asset included in account 182318 for each month during the base year and test year and for each of the most recent 12 months for which actual information is available. In addition, for each regulatory asset included in this account, indicate whether the regulatory asset was specifically authorized by the Commission. If so, provide the Case number and page cite. In addition, for each regulatory asset included in this account, indicate why the Company believes it is appropriate to include in capitalization and rate base.

e. Describe the Coal Ash Spend – Retail (NC & MW) in account 182471. Describe the references to "Retail" and to "NC" and "MW." Describe the origin of these costs and explain why they should be included in capitalization and rate base for Kentucky retail ratemaking.

f. Provide a schedule showing the balance of account 182471 for each month during the base year and test year and for each of the most recent 12 months for which actual information is available. In addition, indicate whether the regulatory asset was specifically authorized by the Commission. If so, provide the Case number and page cite.

g. Describe the Deferred Gas Integrity Costs in account 182715. Confirm that the Deferred Gas Integrity Costs are recovered through the PRP rider. Demonstrate that this cost is not included in electric capitalization used to calculate the electric revenue requirement and deficiency in this proceeding.

h. Describe the Unappr Undistr Subsid Earnings in account 216100. Identify each subsidiary and provide the Unappr Undistr Subsid Earnings for each subsidiary at the end of each month during the base year and test year. Provide all workpapers in support of the amounts provided. Explain why this component of common equity should be included in the capitalization for Kentucky retail ratemaking purposes.

RESPONSE:

a. The Duke Energy Kentucky Deferred DSM Costs in account 0182401 represents the (over)under collected balance of the DSM Charge that Duke Energy Kentucky collects from its customers via Rider DSM. DSM costs are recovered through the Company's DSM rider, not through the base revenue requirement. All DSM related revenues and expenses were eliminated from the test period in Schedule D-2.22.

b. The table below shows the monthly balances for the base period and test period.

Account 182401
Deferred DSM Costs

Base Period		Forecasted Period	
Month	Amount	Month	Amount
16-Dec	$1,660,597	18-Apr	$1,912,597
17-Jan	$855,790	18-May	$1,942,597
17-Feb	$704,926	18-Jun	$1,972,597
17-Mar	$931,818	18-Jul	$2,002,597
17-Apr	$2,248,201	18-Aug	$2,032,597
17-May	$3,156,924	18-Sep	$2,062,597
17-Jun	$1,726,597	18-Oct	$2,092,597
17-Jul	$1,737,597	18-Nov	$2,122,597
17-Aug	$1,748,597	18-Dec	$2,152,597
17-Sep	$1,759,597	19-Jan	$2,154,597
17-Oct	$1,770,597	19-Feb	$2,156,597
17-Nov	$1,781,597	19-Mar	$2,158,597

Note: The amounts provided include gas and electric.

The Company made no adjustment to capitalization. The deferral balance is exclusively related to a cash flow issue (i.e., over- and under-collection) that must be financed by shareholders.

c. Other Reg Assets - Gen Acct (account 0182318) is used to record Unrecognized Costs (actuarial gain/loss, prior service cost/credit) associated with the company's Qualified Pension plans, attributable to plan participants assigned to Duke Energy Kentucky. In accordance with US GAAP, the Company remeasures its projected benefits obligation annually at fiscal year-end. Remeasurement adjustments are recorded to account 0182318 and amortized over the estimated remaining service life of active participants, approximately nine years.

d. The following table presents the balances in Other Reg Assets - Gen Acct (account 0182318) for each month during the base year and test year and for each of the most recent 12 months for which actual information is available:

0182318 - Other Reg Assets-Gen Acct

	(a)	Base Year		Test year
	Dec 2016	$ 1,566,515	Apr-18	$22,959,312
	Jan 2017	1,566,515	May-18	$22,928,675
	Feb 2017	1,555,969	Jun-18	$22,898,039
(b)	Mar 2017	23,753,974	Jul-18	$22,867,403
	Apr 2017	23,748,701	Aug-18	$22,836,767
	May 2017	23,743,428	Sep-18	$22,806,130
	Jun 2017	23,425,825	Oct-18	$22,775,494
	Jul 2017	23,420,552	Nov-18	$22,744,858
	Aug 2017	23,415,279	Dec-18	$22,714,222
	Sep 2017	23,097,676	Jan-19	$22,683,585
	Oct 2017	23,092,403	Feb-19	$22,652,949
	Nov 2017	23,087,130	Mar-19	$22,622,313

(a) *The most recent 12 months is the same period as Base Year*
b) *Increase due to reclassification of amount previously recorded in account 186 (Miscellaneous deferred debits)*

These costs have been recorded to a regulatory asset account in accordance with FERC Accounting and Reporting Guidance to Recognize the Funded Status of Defined Benefit Postretirement Plans (Docket No. A107-1-000). The Company made no adjustment to capitalization for this regulatory asset because it represents an investment by shareholders.

e. Account 182471 is used to record the deferred recovery of the actual CCR compliance costs and related carrying charges necessary for closing the coal ash pond at East Bend. This general ledger account number is used by multiple jurisdictions, and the account name reflects the nature of the account as Retail ratepayers ("Retail") for North Carolina ("NC") and Mid-West ("MW"). Note Mid-West would apply to Duke Energy Kentucky. The balances for the various jurisdictions are maintained separately in the general ledger based on specific jurisdictional business unit designations (for example, Duke Energy Kentucky's fossil business unit is 75081). These costs are associated with settlement of the Asset Retirement Obligation related to closing the East Bend coal ash pond in accordance with the CCR Rule. The Company has made no adjustment to capitalization for this regulatory asset but would be willing to make an adjustment given the balance is accruing carrying costs.

f. See table below showing the balance in account 182471 for each month starting in November 2016 through March 2019. This regulatory asset was authorized by the Commission in Case No. 2015-00187.

0182471 - Coal Ash Spend-Retail 75081 - DE Kentucky Fossil		
	Fiscal Year and Period	**Ending Balance**
Actuals	201611	7,612,188.40
Actuals	201612	8,034,024.86
Actuals	201701	8,449,980.23
Actuals	201702	8,931,592.93
Actuals	201703	9,657,665.70
Actuals	201704	9,987,002.29
Actuals	201705	10,681,728.06
Actuals	201706	11,022,923.02
Actuals	201707	11,328,447.39
Actuals	201708	11,670,376.76
Actuals	201709	11,949,160.57
Actuals	201710	12,486,772.53
Projection	201711	12,995,254.64
Projection	201712	13,416,937.23
Projection	201801	14,123,849.79
Projection	201802	14,834,276.49
Projection	201803	15,521,338.88
Projection	201804	16,252,384.24
Projection	201805	16,987,682.25
Projection	201806	17,396,464.80
Projection	201807	17,807,625.31
Projection	201808	18,221,177.64
Projection	201809	18,637,135.67
Projection	201810	19,055,513.42
Projection	201811	19,476,324.96
Projection	201812	19,899,584.44
Projection	201901	20,176,427.99
Projection	201902	20,454,881.99
Projection	201903	20,734,955.81

g. The Duke Energy Kentucky Deferred Gas Integrity Costs in account 0182715 reflect the costs incurred related to gas main pressure testing that was necessary in order to maintain Duke Energy Kentucky's natural gas pipeline systems' historic maximum allowed operating pressure

("MAOP") in accordance with Federal regulations. This regulatory asset was authorized by the Commission in Case No. 2016-00159 and no recovery mechanism is currently in place. These costs have been excluded from electric capitalization via the rate base ratio calculation that allocates total Company capitalization between electric and gas (See WPA-1c and WPA-1d).

h. Duke Energy Kentucky does not have any subsidiary entities. Duke Energy has used account 0216100, Unappr Undistr Subsid Earnings, to reflect the transfer of prior years' income and dividends, if applicable, to retained earnings for fiscal years ended 2014 and 2016. In 2015, the transfer is reflected in account 0216000, Unapprop Retained Earnings. The sum of the balances in these account represents the amount of Retained Earnings that is applicable to Duke Energy Kentucky and thus should be included in the capitalization for retail ratemaking purposes.

PERSON RESPONSIBLE:

a. Sarah E. Lawler / David L. Doss Jr.
b. Robert H. Pratt / David L. Doss Jr. / Sarah E. Lawler
c. David L. Doss Jr.
d. Robert H. Pratt / David L. Doss Jr. / Sarah E. Lawler
e. Cynthia S. Lee / Sarah E. Lawler
f. Cynthia S. Lee
g. David L. Doss Jr. / Sarah E. Lawler
h. David L. Doss Jr.

EXHIBIT ____ (LK-22)

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-034

REQUEST:

Refer to the Lee Testimony, page 11, lines 10-14 and the Lawler Testimony, Attachment SEL-2, pages 9 and 10.

a. Confirm that Duke Kentucky is proposing to recover estimated and previously incurred costs through its environmental surcharge.

b. Explain how recovery of the East Bend Coal Ash ARO through the environmental surcharge complies with the requirement of KRS 278.183(2) that costs recovered through the environmental surcharge be included on customer bills "in the second month following the month in which the costs are incurred."

RESPONSE:

a. Yes. The East Bend Coal Ash ARO that the Company is proposing to amortize and recover through the Environmental Surcharge Mechanism (ESM) is calculated based on costs incurred to-date and not already recovered in base rates, as well as the future estimated costs to be incurred.

b. The ARO represents costs incurred to comply with federal, state, or local environmental regulations related to coal combustion as described in 278.183(1). Consistent with 278.183(2), the recovery of costs pursuant to subsection (1) of 278.183, that are not already included in existing rates shall be by an environmental surcharge to existing rates imposed as a positive or negative adjustment to the customer bills in the second month following the month in which the costs are incurred. The ARO deferral and the associated accretion and depreciation expense were approved by the Commission in Case No. 2015-00187. The currently pending case is the Company's first base electric rate case since 2006, so the ARO costs are not already included in base rates.

The recovery methodology through an amortization period that Duke Energy Kentucky is requesting minimizes the base rate impact to customers of the costs associated with closing the East Bend ash basin by spreading the recovery of levelized costs over a longer period of time in a transparent manner through the ESM. The Company's proposal is thematically consistent with similar levelization treatment of incremental fuel expense recovered through the Fuel Adjustment Clause (FAC) that is periodically permitted by the Commission so to minimize the volatility of the FAC to customers. As a result, the Company is requesting recovery of the ARO over a period of ten years (2018 – 2028). As outlined on Schedule CSL-1 included in the direct testimony of Cynthia S. Lee, a significant portion of the costs will have already been incurred by the time the first environmental surcharge is filed. The proposed recovery schedule begins in June 2018 with straight-line recovery through May 2028. The Company's proposal provides an extended benefit to the ratepayers by not recovering these costs immediately in the second month following the month in which the costs are incurred where customer would experience higher costs in the nearer term with lower costs in the later years. The Company also believes including the entire ARO in the ESM to be more transparent and less cumbersome than including a portion of the ARO amortization in base rates and a portion of the ARO amortization in the ESM.

If the Commission does not agree with the Company's proposal to include the total costs of the ARO for recovery in the ESM, then the Company's rate case revenue requirement must then be adjusted to account for the recovery of the ARO balance and amortization in base rates. The incremental costs of retirement should then be recovered through the ESM.

PERSON RESPONSIBLE: Sarah E. Lawler