COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR (1) AN ADJUSTMENT OF ELECTRIC RATES; (2) APPROVAL OF NEW TARIFFS; (3) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (4) ALL OTHER REQUIRED APPROVALS AND RELIEF	)	**CASE NO. 2022-00372**

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

OFFICE OF THE ATTORNEY GENERAL OF THE COMMONWEALTH OF KENTUCKY

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

MARCH 10, 2023

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DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. 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 forty years, as a consultant in the industry since 1983 and as an employee of The Toledo Edison Company from 1976 to 1983. I have testified as an expert witness on ratemaking, accounting, finance, tax, restructuring, mergers and acquisitions, system planning, resource acquisition, and distribution system performance 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 dozens of occasions, including base rate (electric, gas, and water), environmental surcharge, fuel adjustment clause, resource acquisition, and merger and acquisition proceedings involving Duke Energy Kentucky, Inc. ("Company" or "Duke Kentucky"), 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"), Columbia Gas of Kentucky, Inc. ("Columbia"), Kentucky-American Water Company ("KAW"), and Water Service Corporation of Kentucky ("WSCK").[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 address and make recommendations on specific issues that affect the Company's base revenue requirement and on numerous proposals by the Company to modify existing tariffs and to establish new programs and related tariffs.[2]

Q. Please summarize your testimony on revenue requirement issues.

A. I address and make the following recommendations that affect the Company's revenue requirement.[3]

I recommend that the Commission reduce rate base by the zero-cost vendor

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

[2] The effects of the issues that I address are reflected in the table in the Summary section of Mr. Futral's Direct Testimony and in the electronic workpapers filed by the AG in conjunction with Mr. Futral's Direct Testimony.

[3] The amounts shown for each recommendation are reflected in the table summarizing effects of all AG recommendations presented in the Summary section of Mr. Futral's Direct Testimony.

financing for the Company's purchases of fuel and limestone included in inventories as reflected in the related accounts payables balances.

I recommend that the Commission reflect the actual 1.46 collection lag days in the collection component of the revenue lag days in the calculation of cash working capital included in rate base using the lead/lag approach.

I recommend that the Commission deny without prejudice the Company's request to amortize and recover the planned maintenance outage expense deferrals regulatory asset and the forced outage expense deferrals regulatory asset in this proceeding. The Company provided no justification for costs in excess of the amounts included in base revenues for these expenses. In addition, the Company's request is premature until the Commission completes its pending investigation in Case 2022-00190.[4]

I recommend that the Commission extend the amortization period and recalculate the levelized recovery of the East Bend 2 deferred Operations and Maintenance ("O&M") expense regulatory asset to reflect a probable retirement date reflected in the depreciation rates for East Bend 2.

I recommend that the Commission reject the Company's request to accelerate the East Bend probable retirement date and shorten the remaining service life for East Bend 2. The Commission will have the opportunity in a future Certificate of Public

[4] Case No. 2022-00190, *Electronic Investigation of the Fuel Adjustment Clause Regulation 807 KAR 5:056, Purchased Power Costs, and Related Cost Recovery Mechanisms* (Ky. PSC Nov. 2, 2022).

Convenience and Necessity ("CPCN") proceeding to determine whether new capacity is more economic than continuing to operate East Bend 2 until 2041.

I recommend that the Commission include the decommissioning expense for its generating units as a separate and standalone expense in the base revenue requirement instead of including it as a component of the depreciation rates and expense. The Company's methodology overstates the expense.

I recommend that the Commission limit the escalation of the decommissioning cost and the resulting expense to the test year and reject the Company's request to escalate the cost through the probable retirement dates.

I recommend that the Commission remove the estimated end of life materials and supplies from the decommissioning cost estimate and instead allow recovery of these costs through the new Rider GTM.

Q. Please summarize your testimony on the Company's proposed modifications to existing rider tariffs, your proposed modification to the existing Rider Environmental Surcharge Mechanism tariff, and the Company's proposed new programs and related new rider tariffs.

A. I address and make the following recommendation in response to the numerous proposals by the Company to modify existing tariffs and/or the recoveries through those tariffs and to establish new programs and related tariffs.

I recommend that the Commission approve the Company's request to modify the present Fuel Adjustment Clause ("Rider FAC") to eliminate seasonal and monthly volatility. The Company's proposal affects only the timing of the FAC recoveries; it does not affect the amounts eligible for FAC recovery.

I recommend that the Commission deny the Company's request to transfer environmental costs from recovery through the Rider Environmental Surcharge Mechanism ("Rider ESM") to the base revenue requirement. My recommendation reduces the Company's requested base rate increase; however, the reduction in the base revenue requirement is offset by the continued recovery of these costs through the ESM revenue requirement.

I recommend that the Commission extend the amortization period and recovery of the East Bend Coal Ash Asset Retirement Obligations ("ARO") included in the ESM revenue requirement to coincide with the probable retirement date for East Bend 2 reflected in the depreciation rates that are authorized in this proceeding, whether that is 2041, as I recommend, or 2035, as the Company proposes.

I recommend that the Commission adopt the Company's proposed new Generation Asset True-Up Mechanism ("Rider GTM"), but *only* if it adopts my recommendations to modify the proposed Rider GTM to ensure that the Company recovers the actual costs of the retired generating units, no more and no less. I recommend modifications to the Company's proposed GTM that are necessary to ensure that the Company does not recover the undepreciated remaining costs of the generating units twice, once through base rates and a second time through Rider GTM, ensure the timely reduction in rates coincident with the reduction in non-fuel and non-depreciation operating expenses, and ensure that other calculation errors and other flaws in the proposed rider GTM language are corrected.

I recommend that the Commission reject the proposed new Electric Vehicle Site Make Ready Service ("MRC") program and related costs through the proposed Rider MRC tariff. Instead, I recommend that this proposed program be combined with the Company's proposed Electric Vehicle Service Equipment ("ESVE") program, the related Rider MRC tariff be combined with the Company's proposed Rider ESVE tariff, and all costs for both programs or the combined program be recovered exclusively from customers participating in both programs or a single combined program and not from customers that do not participate in the programs or program.

I recommend that the Commission approve the Company's proposed ESVE program and the related tariff, subject to my recommendations regarding the proposed MRC program and the related Rider MRC tariff.

I recommend that the Commission reject the Company's proposed new Rider Incremental Local Investment Charge ("Rider ILIC") tariff. It is poorly conceived, introduces a new alternative form of regulation, indeed effectively self-regulation, and will allow the Company through an "agreement" with a local government authority to establish rates not only within the boundaries of the local government authority, but potentially systemwide.

I recommend that the Commission reject the Company's proposed new Rider

Clean Energy Connection ("Rider CEC") tariff at this time. The Company should provide a revised and more developed Rider CEC if and when it files a CPCN Application for a new solar facility. There is no need for the Commission to consider and resolve all problems with this proposed Rider CEC in this proceeding.

I recommend that the Commission reject the Company's proposed new "comprehensive" hedging program in this proceeding and instead initiate a new proceeding to consider the scope and long-term cost effectiveness of the proposed comprehensive hedging program or the continuation of the previously approved back up power supply plan. The Company failed to provide a sufficiently detailed description of the components of its proposed comprehensive hedging program or a study addressing the long-term cost effectiveness of the program in this proceeding.

II. RATE BASE ISSUES

A. Fuel And Lime Inventories Included In Rate Base Should Be Offset By Zero-Cost Vendor Financing

Q. Describe the Company's purchases of fuel and lime from its vendors and the additions to the respective inventory accounts, related accounts payable, and the subsequent payment of those accounts payable.

A. When the Company purchases coal and lime from its vendors, it records these purchases as additions to its coal fuel inventory and lime inventory balance sheet accounts and simultaneously records the same amounts to the vendor accounts payables balance sheet accounts. When the Company subsequently pays the vendors, it records these cash payments as reductions to the vendor accounts payables balance sheet accounts and to the cash balance sheet account.

Q. Does the Company actually finance its purchases of fuel and lime from the date it purchases the fuel and lime from its vendors until it actually pays the vendors?

A. No. The Company's vendors provide temporary financing during this period. This temporary vendor financing is a zero-cost form of financing. The Company does not finance the fuel and lime that it purchases until it actually pays its vendors.

Q. Is the Company's delayed payment to vendors for its fuel and lime inventories captured in the cash working capital calculations?

A. No. In the cash working capital calculations using the lead/lag approach, only the lead/lags on *cash expenses* are measured and included; the cash working capital calculations do *not* measure or include temporary vendor financing for *balance sheet* assets.

Instead, the accounts payable amounts related to fuel and lime inventories must be considered separately and subtracted directly from rate base in the same manner that the fuel and lime inventories *balance sheet* amounts are considered separately and added directly to rate base.

Q. Has the Commission previously adopted adjustments to reflect zero-cost vendor financing of balance sheet asset amounts in other recent base rate case proceedings?

A. Yes. The Commission subtracted the construction accounts payable and the prepayments accounts payables from rate base in the most recent Kentucky Power Company base rate case proceeding.[5]

The Commission also subtracted the construction accounts payable from rate base in the most recent Atmos Energy Corporation base rate case proceeding. The Commission stated in its final Order the following:

> In a number of recent base rate cases where the revenue requirement is determined using rate base, the Commission has accepted adjustments to remove accounts payable from working capital amounts because the utility does not finance these amounts. The same reasoning exists here. Therefore, the Commission finds that this adjustment is reasonable and is accepted.[6]

Q. What is your recommendation?

A. I recommend that the Commission reduce rate base by the zero-cost vendor financing for the Company's purchases of fuel and limestone included in inventories as reflected in the related accounts payables balances.

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[5] Case No. 2020-00174, *Electronic Application of Kentucky Power Company for (1) A General Adjustment of its Rates for Electric Service; (2) Approval of Tariffs and Riders; (3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; (4) Approval of a Certificate of Public Convenience and Necessity; And (5) All Other Required Approvals and Relief* (Ky. PSC Jan. 13, 2021), Order at 10.

[6] Case No. 2021-00214, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates*, (Ky. PSC May 19, 2022), Order at 16 – 17.

Q. What are the effects of your recommendation?

A. The effects are a $6.459 million reduction in rate base and a $0.604 million reduction in the base revenue requirement and requested base rate increase.

B. <u>Revenue Lag Days In Cash Working Capital Calculation Are Excessive And Should Be Reduced to Reflect The Company's Sale Of Customer Accounts Receivables</u>

Q. Describe the Company's sale of its customer accounts receivables to Cinergy Receivables Company, LLC.

A. The Company sells the prior day's customer accounts receivables on a daily basis to an affiliate financing entity, Cinergy Receivables Company, LLC ("CRC").[7] CRC is an affiliated special purpose financing entity used to accelerate the Company's conversion of receivables into cash on a daily basis rather than waiting until customers actually pay their bills. CRC borrows against a short-term loan facility to obtain the cash used to acquire the receivables from the Company and other Duke Energy affiliates. This process recurs on a daily cycle, although the Company only records the cumulative effects of these transactions on its accounting books at the end of each month.[8] The Company records the cash received as an increase to the cash balance

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[7] Duke Kentucky's response to AG 1-93. I have attached a copy of this response as my Exhibit___(LK-2).

[8] Duke Kentucky's response to AG 1-94(b) and (d). I have attached a copy of this response as my Exhibit___(LK-3).

sheet account and the receivables sold as a credit to its receivables account, which it records in a receivables contra-account.

The cash received from CRC for the receivables sold to CRC reflects a modest discount to compensate CRC in cash for the interest expense on the debt CRC issues to finance its purchases of the receivables from the Company and for the estimated uncollectible amounts of those receivables. The Company records the two discount amounts as interest expense and as uncollectible accounts expense, respectively.

Q. Respond to the Company's assertion in response to AG discovery that the sale of its receivables does not result in daily flows of cash between it and CRC.[9]

A. While procedurally this may be correct, substantively it is incorrect. The Company actually sells its receivables to CRC daily for cash. The Company actually collects cash from its customers to remit to CRC daily. However, it only remits or collects the net of these two daily and recurring cash flows to CRC on a monthly basis. This monthly true-up is a logistical and administrative convenience, but the underlying transaction activities occur daily.

The transaction activities are similar to the recurring and unceasing cycle of water flowing in and then ebbing out in an ocean, even while the volume of the water itself remains unchanged throughout each cycle. The Company would have the

[9] Duke Kentucky's response to AG 2-49(a). I have attached a copy of this response as my Exhibit___(LK-4).

Commission view the daily transactions as a snapshot of the underlying activity, while the reality is that there is an unceasing cycle of cash flowing in from the sales of the receivables to CRC and cash ebbing out when the cash received from customers is remitted to CRC on a recurring daily basis.

Q. What effect does the Company's sale of its customer accounts receivable have on the conversion of its receivables into cash?

A. The Company's daily sales effectively and substantially accelerates the conversion of its customer receivables into cash and significantly reduces the collection lag days (the number of days between the customer billing and receipt of the customer payments) that should be reflected in the cash working capital calculations. Absent the sales of the receivables on a daily basis, the Company would wait an average of 27.02 days from the date of customer billing to the date when it receives cash payment for service. With the sales of the receivables to CRC, the Company accelerates the conversion of the receivables to cash and waits an average of only 1.46 days from the date of customer billing to the date when it receives cash for service.

Q. Why is the Company's sale of its customer accounts receivables beneficial to customers if properly reflected in the ratemaking process?

A. The benefit is twofold. First, the Company accelerates the conversion of its customer receivables into cash, which significantly reduces the amount necessary to finance its customer receivables through traditional common equity and long-term debt sources of financing. This is reflected in a lower cash working capital requirement due to the lesser collection lag days component in the revenue lag days. Second, the interest expense on the collateralized debt financing reimbursed to CRC is substantially less than the traditional weighted average cost of common equity and long-term debt financing for customer receivables that otherwise would be incurred.

Q. Does the Company's cash working capital study correctly reflect the daily sales of its customer accounts receivables to an affiliate financing entity?

A. No. The Company's cash working capital calculation ignores the daily sales of its customer accounts receivables and reflects 27.02 collection lag days, the collection lag days component of the 45.91 total revenue lag days.[10] If the daily sales of its receivables were correctly included in the cash working capital calculation, then it would reflect the actual 1.46 collection lag days.[11]

Q. Why is that important?

A. The revenue lag days directly affects the cash working capital included in rate base

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[10] Refer to the Revenues tab in the Company's AG-DR-01-096_Attach_3_Revised_Duke_KY_Forecasted_Period_Lead_Lag_Summary Excel workbook. This Excel spreadsheet shows the Company's revised calculation of each component of the revenue lag days, including the service days lag, the billing days lag, and the collection days lag.

[11] I calculated the 1.46 collection lag days based on the sale of receivables each business day (52 weeks * 5 days) less holidays (10 days).

and the base revenue requirement. The greater the revenue lag days, the greater the cash working capital. The fewer the revenue lag days, the lesser the cash working capital.

In its calculation of cash working capital, the Company used 45.91 revenue lag days, assuming there are no sales of its customer accounts receivables. The Company netted the 45.91 revenue lag days against its calculation of 45.19 average expense lag days for all cash expenses.[12] It then multiplied the 0.72 net revenue lag days times the average daily cash expense for all included expenses to calculate the $0.506 million in cash working capital that it included in rate base for the test year.[13]

However, if the collection lag days are reduced to the correct 1.46 days to reflect the daily sale of the receivables to CRC from the incorrect 27.02 collection lag days used by the Company, which assumes there are no such sales, then the revenue lag days are reduced to 20.35 days from the Company's 45.91 days, the net revenue lag days (revenue lag days less the average cash expense lag days) are reduced to *negative* 24.84 days from the Company's 0.72 days, and the cash working capital is reduced to *negative* $17.438 million compared to the Company's $0.506 million, all else equal.

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[12]Refer to the Lead Lag Summary tab in the Company's AG-DR-01-096_Attach_3_Revised_Duke_KY_Forecasted_Period_Lead_Lag_Summary Excel workbook.

[13] Refer to Duke Kentucky's response to AG 1-96. The Company corrected and revised its calculation of cash working capital and reduced it from $5.425 million to $0.506 million. Mr. Futral addresses the effects of correcting this error and other errors in his Direct Testimony and quantifications.

Q. What is your recommendation?

A. I recommend that the Commission reflect the actual 1.46 collection lag days in the collection component of the revenue lag days in the calculation of cash working capital included in rate base.

Q. What is the effect of your recommendation?

A. The effect is a $17.945 million reduction in rate base and a $1.677 million reduction in the base revenue requirement and requested base rate increase.

III. OPERATING INCOME ISSUES

A. Amortization Periods for Planned Outage Expense And Forced Outage Expense Regulatory Assets Should Be Longer to Mitigate Magnitude of Requested Base Rate Increase

Q. Describe the Company's accounting for planned outage expense deferrals and forced outage expense deferrals.

A. The Company presently defers its actual planned outage expense to a regulatory asset and reduces the regulatory asset by the expense accruals recovered through base revenues. The Company presently recovers $7.177 million for the expense accruals through base revenues. The Company proposes to continue to recover this same amount in the test year.[14]

The Company also presently defers its forced outage expenses not recoverable through the FAC to a regulatory asset and reduces the regulatory asset by the expense accruals recovered through base rates. The Company presently recovers $1.610 million for the expense accruals through base revenues. The Company proposes to continue to recover this same amount in the test year.[15]

The Commission authorized both deferrals in Case 2017-00321 in conjunction with the adoption of adjustments proposed by the AG to reduce the expenses included in the base revenue requirement compared to the amounts requested by the Company.[16] The Company sought no change in the expense accruals and no amortization or recovery of the regulatory assets in Case 2019-00271.[17]

Q. Describe the Company's requests to amortize and recover these two regulatory assets in this proceeding.

A. The Company seeks $1.662 million to amortize and recover the planned outage

[14] Direct Testimony of Lisa Steinkuhl ("Steinkuhl Testimony"), at 18 – 19.
[15] *Id.*
[16] Case No. 2017-00321, *Electronic Application of Duke Energy Kentucky, Inc. for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; And 5) All Other Required Approvals and Relief* (Ky. PSC Apr. 13, 2018), Order at 15 – 16.
[17] Duke Kentucky's response to AG 2-56 in this proceeding; Case No. 2019-00271, *Electronic Application of Duke Energy Kentucky, Inc. for 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief* (Ky. PSC Apr. 27, 2020).

expense regulatory asset over five years in this proceeding.[18] The Company seeks $0.364 million to amortize and recover the forced outage expense regulatory asset over five years.[19] The Company did not include either regulatory asset or the related liability accumulated deferred income taxes ("ADIT") in rate base.

Q. Do you agree with the Company's request to amortize and recover the planned outage expense regulatory asset over five years?

A. No. As a practical matter, the regulatory asset for the planned outage expense could be positive or negative depending on the cumulative actual planned outage maintenance expenses compared to the cumulative expense accruals recovered through the revenue requirement. The Company's actual planned outage maintenance expense varies from year due to the scope and frequency of the actual outage activities. The deferral mechanism should net to zero over the planned maintenance outage cycles unless there are exceptional circumstances, all else equal.

In this case, the Company has incurred substantially more in actual planned outage expenses compared to the expense accruals included in the base revenue requirement since the effective date when base rates were reset in Case 2017-00321. The Company now seeks to amortize and recover those deferred expenses in addition to the forecast planned outage maintenance expense in the test year, essentially

[18] Steinkuhl Testimony at 17 – 18; Application at Schedule WPD-2-27a.
[19] *Id.*

doubling up its request in this proceeding to recover the additional planned outage expenses that it incurred in prior years compared to what it was allowed in the base revenue requirement.

Q. Has the Company made any attempt to demonstrate that the additional planned outage maintenance expenses incurred over the last several years were prudent, reasonable, and necessary?

A. No. The Company simply seeks recovery on the basis that it incurred the expenses. However, the Company bears the burden to demonstrate that expenses in excess of the expenses allowed in the base revenue requirement were prudent, reasonable, and necessary. It has not done so in the Application or Direct Testimony. Nor should it be allowed to provide such justification in its Rebuttal Testimony when the AG can no longer issue discovery or respond to such testimony in its Direct Testimony.

Q. Has the Company made any attempt to demonstrate that the planned outage maintenance expenses regulatory asset cannot and/or will not decline in the future if it diligently manages its planned outage maintenance expenses going forward?

A. No. The Company has not done so in the Application or Direct Testimony. Nor did it provide such a multiyear forecast of planned maintenance outage expenses in its Application or Direct Testimony. Although the Company provided a schedule in response to AG discovery showing that its forecast planned outage maintenance expense in 2023 and 2024 were set "to the amount approved by the Commission to be included in base rates,"[20] there is no certainty that the actual planned outage expense in those years will equal or exceed the authorized expense accruals. In fact, the Company's forecast planned outage expenses in 2023 and 2024 are less than the authorized expense accruals, which will have the effect of reducing the deferrals accumulated to the regulatory asset that the Company seeks to amortize and recover in this proceeding.[21]

Q. What is your recommendation?

A. I recommend that the Commission deny without prejudice the Company's request to amortize and recover these deferred expenses in this proceeding and direct the Company to seek to work down the prior deferrals to the regulatory asset before the effective date when rates are reset in its next base rate case proceeding. This will provide the Company a ratemaking behavioral incentive to control its planned outage maintenance expenses until the Commission again can consider recovery of any

[20] Duke Kentucky's response to AG 2-56(b).

[21] Duke Kentucky's response to AG 2-56(c). In its public response, the Company redacted the amounts, but described the effects if forecast expenses beyond the test year are considered. Similarly, I have not cited the amounts, but rather, have described the effects if forecast expense in 2023 and 2024, the two years affecting the test year in this proceeding, are considered. Any forecast of expenses beyond the end of the test year are not relevant in this proceeding and, to extent the actual expenses in the test year and thereafter are more or less than the expense accruals authorized in this proceeding, the differences will be captured through the deferrals to the regulatory asset and can be considered again in the next base rate case proceeding.

remaining deferred expenses in the Company's future base rate case proceedings.

Alternatively, I recommend that the Commission set the amortization period to ten years. This will mitigate the effects of the amortization on the base revenue requirement in this proceeding.

Q. What is the effect of your recommendation?

A. The effect of my primary recommendation is a reduction of $1.662 million in regulatory asset amortization expense and a reduction in the Company's claimed revenue requirement and base rate increase of $1.665 million after gross-up for Commission assessment fees and bad debt expense.

The effect of my alternative recommendation is a reduction of $0.831 million in regulatory asset amortization expense and a reduction in the Company's claimed revenue requirement and base rate increase of $0.832 million after gross-up for Commission assessment fees and bad debt expense.

Q. Do you agree with the Company's request to amortize and recover the forced outage expense regulatory asset over five years?

A. No. Similar to my comments regarding the planned outage maintenance expense regulatory asset, the Company simply seeks recovery on the basis that it incurred the expenses. The forced outage expenses are the expenses that it incurred due to forced outages, but could not recover through the FAC.

The Company made no attempt to demonstrate that the forced outages and the related incremental expenses deferred to the regulatory asset were prudent, reasonable, and necessary. However, the Company bears the burden to demonstrate that expenses in excess of what were allowed in the base revenue requirement were prudent, reasonable, and necessary. It has not done so in its Application or Direct Testimony. Nor should it be allowed to provide such justification in its Rebuttal Testimony when the AG can no longer issue discovery or respond to such testimony in its Direct Testimony.

Finally, the Company has no ratemaking incentive to minimize forced outages or the related expenses if it can simply defer and recover, without any justification, the incremental expenses that it incurred due to the forced outages, but cannot recover through the FAC. This is an issue that the Commission identified in its Order initiating an investigation into the recovery of fuel and purchased power expenses in Case 2022-00190.[22] The investigation remains in process. Any decision as to the recovery of the prior deferrals to the regulatory asset should be deferred until after the Commission issues a final Order in Case 2022-00190.

Q. What is your recommendation?

[22] Case No. 2022-00190, *Electronic Investigation of the Fuel Adjustment Clause Regulation 807 KAR 5:056, Purchased Power Costs, and Related Cost Recovery Mechanisms* (Ky. PSC Nov. 2, 2022), Order at 7 – 10.

A. I recommend that the Commission deny without prejudice the Company's request to amortize and recover these deferred expenses in this proceeding. This will provide the Company a ratemaking behavioral incentive to minimize its forced outages and the incremental expenses associated with those outages until the Commission completes its investigation in Case 2022-00190 and can again consider recovery of any remaining deferred expenses in the Company's future base rate case proceedings.

Alternatively, I recommend that the Commission set the amortization period to ten years. This will mitigate the effects of the amortization on the base revenue requirement in this proceeding.

Q. What is the effect of your recommendation?

A. The effect of my recommendation is a reduction of $0.364 million in regulatory asset amortization expense and a reduction in the Company's claimed revenue requirement and base rate increase of $0.365 million after gross-up for Commission assessment fees and bad debt expense.

The effect of my alternative recommendation is a reduction of $0.182 million in regulatory asset amortization expense and a reduction in the Company's claimed revenue requirement and base rate increase of $0.182 million after gross-up for Commission assessment fees and bad debt expense.

B. <u>East Bend 2 Deferred O&M Expense Regulatory Asset Amortization Period Should Be Extended to Mitigate the Magnitude of Requested Base Rate Increase</u>

Q. Describe the East Bend 2 deferred O&M expense regulatory asset and the amortization expense included in the Company's requested base revenue requirement.

A. The Company included $4.498 million for recovery of the East Bend 2 deferred O&M expense regulatory asset in its claimed base revenue requirement.[23] The Commission previously authorized the Company to defer incremental East Bend 2 O&M expense to a regulatory asset from the date it acquired the remaining ownership of that generating unit until the O&M expense was included in and recovered through base rates.[24] The Commission subsequently authorized recovery of the East Bend deferred O&M expense regulatory asset on a levelized basis using a debt only rate of return over ten years.[25]

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[23] This amount is calculated based on $4.490 million in amortization expense grossed up for Commission assessment fees and bad debt expense.

[24] Case 2014-00201, *Application of Duke Energy Kentucky, Inc. for (1) A Certificate of Public Convenience and Necessity Authorizing the Acquisition of the Dayton Power & Light Company's 31% Interest in the East Bend Generating Station; (2) Approval of Duke Energy Kentucky, Inc.'s Assumption of Certain Liabilities in Connection with the Acquisition; (3) Deferral of Costs Incurred as Part of the Acquisition; And (4) All Other necessary Waivers, Approvals, and Relief* (Ky. PSC Dec. 4, 2014), Order at 10 – 11.

[25] Case No. 2017-00321, *Electronic Application of Duke Energy Kentucky, Inc. for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; And 5) All Other Required Approvals and Relief* (Ky. PSC Apr. 13, 2018), Order at 25.

Q. Was the ten-year amortization period tied to any specific milestone date, such as the probable retirement date of East Bend 2?

A. No.

Q. Would an extension of the amortization period for this regulatory asset mitigate the requested increase in this proceeding?

A. Yes. An extension of the amortization period for this regulatory asset and others would mitigate the claimed base revenue requirement and the requested increase in this proceeding. The Commission should take advantage of available ratemaking tools to reduce the sheer magnitude of the Company's requested rate increase in this proceeding.

Q. Does the probable retirement date for East Bend 2 used for depreciation and decommissioning expense provide the basis for an appropriate and reasonable amortization period?

A. Yes. The probable retirement date for East Bend 2 provides the basis for an appropriate and reasonable amortization period, regardless of whether that probable retirement date is 2041, as I recommend, or 2035, as the Company proposes. This is appropriate and reasonable, not only from the perspective of consistent amortization and recovery periods, but also because the deferred O&M expense is effectively a form of "acquisition premium" added to the cost incurred to acquire the additional East

Bend 2 capacity.

Q. What is your recommendation?

A. I recommend that the Commission extend the amortization period and recalculate the levelized recovery to reflect a probable retirement date of mid-year 2041, the probable retirement date reflected in the presently approved depreciation rates for East Bend 2.

Alternatively, if the Commission approves the Company's request to accelerate the probable retirement date for depreciation and decommissioning expense purposes, then I recommend that it extend the amortization period and recalculate the levelized recovery to reflect a probable retirement date of mid-year 2035.

Q. What is the effect of your recommendation?

A. The effect is a reduction of $2.760 million in regulatory asset amortization expense and a reduction in the Company's claimed revenue requirement and base rate increase of $2.764 million after gross-up for Commission assessment fees and bad debt expense.

The effect of my alternative recommendation is a reduction of $2.181 million in regulatory asset amortization expense and a reduction in the Company's claimed revenue requirement and base rate increase of $2.184 million after gross-up for Commission assessment fees and bad debt expense.

C. <u>Probable Retirement Date for East Bend 2 Should Not Be Accelerated to 2035 from 2041 for Depreciation And Decommissioning Expense</u>

Q. Describe the Company's request to accelerate the probable retirement date of East Bend 2 to 2035 from 2041 and to shorten the remaining service life used by Company witness Mr. John Spanos to calculate the East Bend depreciation rates, including the decommissioning expense embedded in the depreciation rates.

A. The probable retirement date of East Bend 2 was addressed by several Company witnesses.[26] The reasons cited by these witnesses for accelerating the probable retirement date of East Bend 2 include forecasted, but as yet, unknown, future economic and market conditions; as well as environmental, and investor environmental, societal, and governmental ("ESG") concerns, and "industry trends" in accelerated retirements of coal-fired power plants.

Q. Is it certain that the 600 mW of East Bend 2 capacity will be retired in 2035 or that it will be uneconomic compared to other potential capacity resources in 2035?

A. No. The Company has no specific plan to retire East Bend 2 in 2035. In fact, the Company states in response to the AG discovery that "[t]he decision to retire East

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[26] Direct Testimonies of Amy Spiller ("Spiller Testimony"), at 25 – 26, Sarah Lawler ("Lawler Testimony"), at 5 – 6, Christopher Bauer ("Bauer Testimony"), at 13, Lisa Quilici ("Quilici Testimony"), at 2 – 26, William Luke ("Luke Testimony"), at 11 – 14, John Swez ("Swez Testimony"), at 9 – 10, Scott Park ("Park Testimony"), at 3 – 11, and Joshua Nowack ("Nowack Testimony"), at 45- 46.

Bend 2 in 2035 has not been decisively made yet…"[27] Nor has the Company identified the new capacity resource(s) or when it will acquire the new capacity resource(s) to replace the 600 mW of East Bend 2 capacity. Mr. Luke states that "[t]he Company continues to evaluate the best solution for customers."[28] Mr. Luke further states that [t]he Company's most recent IRP simply described a 'firm dispatchable resource' (FDR) as meeting that need for replacing East Bend . . . [t]he Company will bring those solutions to the Commission in due time, well in advance of any retirements, to ensure there is a seamless transition for customers . . . there is still time to solve the questions of 'what resource will replace East Bend…'"[29]

Similarly, Mr. Park states that the 2021 IRP reflects the retirement of East Bend 2 in 2035, but will be "replaced by what is classified as a Firm Dispatchable Resource (FDR).[30] The FDR classification was used to convey that the specific technology has not yet been chosen but will need to exhibit characteristics of providing firm capacity year round and well as 24 hours per day and will need to be able to dispatch up and down in response to customer loads and market prices."[31]

Q. Why is the uncertainty as to the actual retirement date and the replacement capacity relevant to the Commission's decision on the probable retirement date

[27] Duke Kentucky's response to AG 1-19(a).
[28] Luke Testimony at 13 – 14.
[29] *Id*.
[30] Park Testimony at 4.
[31] *Id*.

for East Bend 2 in this proceeding?

A. Fundamentally, the Company has failed to demonstrate that it is or will be uneconomic to continue to operate East Bend 2 after 2035, or that it actually will retire the facility in 2035 or some other date prior to 2041. The Commission does not approve retirements or new capacity in a base rate case proceeding or an IRP proceeding, notwithstanding the Company's 2021 IRP and the retirement of East Bend 2 in 2035 in its "base case" in that IRP proceeding. Rather, the Commission only approves new capacity in a CPCN proceeding. The Company will be required to file an Application in a CPCN proceeding to seek and obtain approval for the new capacity necessary to replace East Bend 2 at some future date. In that CPCN proceeding, the Commission will make the determination as to whether it is or will be economic to retire East Bend 2 prior to 2041. The Company's CPCN filing and the Commission's determination in that proceeding will be based on the facts and circumstances at that future time, not speculation by the Company and its multiple witnesses at the present time in this proceeding.

Q. Ms. Spiller states that "the Company needs to align East Bend's depreciation rates to this service life [2035] to minimize future customers' exposure to the unrecovered net book value of the plant at the time of its retirement."[32] Other

[32] Spiller Testimony at 28.

witnesses make similar statements. Do you agree that such an alignment is necessary or reasonable?

A. No. If indeed it is economic for the Company to acquire new capacity to replace East Bend 2 in 2035 rather than in 2041, then the recovery of the remaining net book value of East Bend 2 in 2035 should be considered a cost of transitioning to the new capacity and recovered, at least in part, from the generation of customers that will be served by the new capacity.

The cost to "clear the way" for and accelerate the transition to new capacity that presumably is more economic than East Bend 2 is not a cost that should be imposed on the present generation of customers in order to benefit future customers. The future customers should bear the remaining cost of the East Bend 2 in exchange for the benefits they will achieve from an earlier transition to lower cost replacement capacity, if in fact, that will be the case.

Q. What is your recommendation for the East Bend 2 probable retirement date and service life reflected in the East Bend 2 depreciation rates for depreciation expense and decommissioning expense?

A. I recommend that the Commission reject the Company's request to accelerate the East Bend probable retirement date and shorten the remaining service life for East Bend 2. The Commission will have the opportunity in a future CPCN proceeding to determine whether new capacity is more economic than continuing to operate East Bend 2 until

2041.

In any event, if the Commission determines in a CPCN proceeding that it is appropriate and reasonable for the Company to acquire new capacity and retire East Bend 2 prior to 2041, then the customers who benefit from the lower cost of the new capacity should be allocated the remaining undepreciated costs of East Bend 2 at that time. In fact, the Company's proposed new Rider GTM will allow the Company to recover the remaining undepreciated net book value of East Bend 2 and other generating units at the date they actually are retired. The new Rider GTM, as modified by my recommendations in this proceeding, not only will ensure that the Company recovers the remaining undepreciated net book value of those generating units, but that it will recover the costs from the future generation of customers who benefit from the lower costs of the replacements. The Commission should use the new Rider GTM for maximum benefit if there is a premature retirement prior to 2041 not only to extend the recovery of the remaining undepreciated net book value, but to further take advantage of the levelized form of recovery through that new rider.

Q. What are the effects of your recommendations on the East Bend 2 depreciation expense and decommissioning expense?

A. The effects are a reduction of \$10.435 million in depreciation expense, a \$2.616 million reduction in accumulated depreciation and increase in rate base, net of the ADIT effects, and a \$10.208 million reduction in the base revenue requirement and requested base revenue increase.[33]

D. Decommissioning Expense Should Be Included And Recovered As A Separate Standalone Expense Instead Of Embedded In Depreciation Rates And Expense

Q. Describe the manner in which the Company incorporates decommissioning expense in the test year revenue requirement.

A. The Company incorporates an estimate of the future decommissioning costs for the East Bend 2, Woodsdale, Crittenden, and Walton generating facilities, and the retired Miami Fort 6 generating unit, into the calculation of the proposed depreciation rates for the operating generating facilities.

Company witness Mr. Kopp estimated the decommissioning costs for the operating and retired generating facilities in 2022 dollars. Mr. Kopp's estimated decommissioning costs made no assumptions as to the probable retirement dates for the generating facilities.

Mr. Spanos escalated the decommissioning costs in 2022 dollars to future probable retirement date dollars using a 2.5% escalation rate for this purpose.[34]

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[33] The Company provided revised depreciation rates assuming that the probable retirement date for East Bend 2 is maintained at 2041 in response to Kroger 1-5. I have attached a copy of this response as my Exhibit___(LK-5). I applied the revised depreciation rates from this response reflecting a retirement date in 2041 to the test year gross plant balances included in rate base for the base revenue requirement. I calculated this effect on the base revenue requirement using test year gross plant after removing the gross plant related to my recommendation to deny the Company's proposal to roll-in the plant costs for four projects from the ESM revenues to base revenues. To the extent that the rate base and depreciation expense for the four projects remains in the ESM, as I recommend, there also will be a reduction in the depreciation expense on those four projects in the ESM.

[34] Duke Kentucky's response to AG 1-118.

Mr. Spanos then added the decommissioning cost estimate in future dollars to the East Bend 2, Woodsdale, Crittenden, and Walton actual remaining net book values at December 31, 2021, the date of his depreciation study, and then divided this sum by the average remaining service lives for each plant account for each of these generating facilities to calculate the proposed depreciation rates.

The Company then utilized the proposed depreciation rates developed by Mr. Spanos to calculate the depreciation expense for each month during the test year. It applied the proposed depreciation rates to the gross plant, including capital additions, less retirements, for each operating generating facility for each month during the test year.

Q. Is there a fundamental problem with the Company's calculation methodology?

A. Yes. The decommissioning expense in the test year is overstated due solely to the Company's methodology compared to calculating and reflecting the decommissioning expense as a separate and standalone expense. This error occurs because the decommissioning expense was included as a component of the depreciation rates calculated using the gross plant at December 31, 2021, the date of the depreciation study, but then the depreciation rates were applied to the gross plant in the test year ending June 30, 2024. To the extent that the gross plant in the test year is greater than the gross plant at December 31, 2021, the decommissioning component in the depreciation rate expense applied to the gross plant in the test year will result in a proportionately greater decommissioning expense than if the decommissioning costs were calculated and reflected as a separate and standalone decommissioning expense.

Q. What is your recommendation?

A. I recommend that the Commission remove the decommissioning expense from the East Bend 2, Woodsdale, Crittenden, and Walton depreciation rates and the resulting calculations of depreciation expense for the test year and instead simply include the decommissioning expense as a separate and standalone expense in the base revenue requirement. This will ensure that the decommissioning expense is not incorrectly increased in the test year by the percentage increase in the East Bend 2, Woodsdale, Crittenden, and Walton gross plant in the test year compared to the gross plant balances at the depreciation study date.

Q. What are the effects of your recommendation to remedy this problem?

A. The effects of removing the decommissioning expense for East Bend 2, Woodsdale, Crittenden, and Walton from the calculation of the depreciation rates and depreciation expense and including it on a standalone basis are a net reduction of $0.857 million in the requested depreciation/decommissioning expense, a $0.215 million reduction in accumulated depreciation/decommissioning and increase in rate base, net of the ADIT effects, and a $0.839 million reduction in the base revenue requirement and requested base revenue increase.

The net effects reflect the net reduction to remove the decommissioning from the depreciation rates and expense of $5.765 million in the requested depreciation expense, a $1.446 million reduction in accumulated depreciation and increase in rate base, net of the ADIT effects, and a $5.640 million reduction in the base revenue requirement and requested base revenue increase. The reductions in the depreciation rates and expense are offset by the decommissioning expense of $4.908 million on a separate and standalone basis, a $1.231 million increase in accumulated depreciation/decommissioning and decrease in rate base, net of the ADIT effects, and a $4.801 million increase in the base revenue requirement and requested base revenue increase.

E. Decommissioning Expense Should Be Reduced to Limit Escalation To Test Year

Q. Is there yet another problem in the Company's calculation of the decommissioning expense?

A. Yes. The escalation applied by Mr. Spanos extends beyond the end of the test year, which already is fully forecasted. In the case of East Bend 2, it results in the decommissioning expense based on a forecast decommissioning cost in 2035, some eleven years after the test year in this proceeding. In the case of the Woodsdale generating units, it results in the decommissioning expense based on a forecast decommissioning cost in 2040, some sixteen years after the test year in this proceeding.

In contrast, the gross plant included in rate base and used to calculate depreciation expense is limited to the capital expenditures through the end of the test year, and does not reflect a forecast of future costs after the test year, and certainly not through 2035 and 2040 for the East Bend 2 and Woodsdale generating facilities, respectively. Also, in contrast to the forecast of gross plant in the test year, which is based on the Company's budget process and reasonably known and certain, the retirement dates for the Company's generating units are not known and certain, nor is the cost in future dollars tied to the retirement dates known and certain.

Q. What is your recommendation for the end date on the escalation of the decommissioning costs for the Company's generating units?

A. I recommend that the Commission limit the escalation of the decommissioning cost and the related expense to the test year and reject the Company's request to escalate the cost through the probable retirement dates. The decommissioning cost is not known and measurable because it has not yet been incurred. The Company's forecast for decommissioning expense based on unknown and uncertain costs for East Bend 2 in 2035 or 2041, some eleven or seventeen years beyond the end of the test year, Woodsdale in 2040, some sixteen years beyond the end of the test year, and the Crittenden and Walton solar facilities in 2047, some twenty-three years beyond the end of the test year, creates a mismatch between all revenues and all other costs used to determine the test year revenue requirement that are forecast for and limited to the test year.

Q. What are the effects of your recommendation to remedy this problem?

A. The effects of limiting the escalation of the decommissioning cost to the test year are a $1.563 million reduction in the decommissioning expense, a $0.392 million reduction in accumulated decommissioning and increase in rate base, including the effects of ADIT, and a $1.529 million reduction in the base revenue requirement and the requested base revenue increase.

F. <u>Decommissioning Expense Should Be Reduced to Remove Estimated End of Life Materials And Supplies Inventories</u>

Q. Describe the materials and supplies inventories included in the decommissioning cost estimate and the decommissioning expense.

A. The decommissioning study includes $8.176 million for East Bend 2 and $4.475 million for Woodsdale in estimated end of life materials and supplies inventories, net of salvage. These amounts are in 2022 dollars.[35] The end of life materials and supplies

[35] Direct Testimony of Jeffrey Kopp ("Kopp Testimony"), at 17, Attachment JTK-1.

inventories comprise 21% of the East Bend 2 decommissioning cost estimate and 40% of the Woodsdale decommissioning cost estimate.

Q. Is it possible to know at this time the inventory items or the dollar amount of those inventories that cannot be salvaged at end of life for each of the Company's generating units?

A. No. The items and the dollar amounts are not known and cannot be estimated with certainty at this time. The attempt to do so is an exercise in speculation.

Q. If there are remaining inventory items and dollar inventory amounts that cannot be salvaged at the end of life for each of the Company's generating units, will those be included in the remaining undepreciated net book value recoverable through the proposed new Rider GTM?

A. Yes. Any such remaining dollar inventory amounts that cannot be salvaged are specifically and properly included in the definition of "retirement costs" recoverable through the new Rider GTM. There is no need to estimate such end of life inventory amounts at this time or recover the estimated amounts prior to the retirement of the generating units. The end of life remaining dollar inventory amounts that cannot be salvaged also are specifically and properly included as recoverable retirement costs in the KPC Decommissioning Rider and the LG&E and KU Retired Asset Recovery riders.

Q. What is your recommendation?

A. I recommend that the Commission remove the estimated end of life materials and supplies from the decommissioning cost estimate and instead allow any future recovery of these costs through the new Rider GTM.

Q. What are the effects of your recommendation to remedy this additional problem?

A. The effects of removing the estimated end of life inventory costs are a $0.757 million reduction in the requested decommissioning amortization expense, a $0.190 million reduction in accumulated decommissioning and increase in rate base, including the effects of ADIT, and a $0.740 million reduction in the base revenue requirement and the requested base revenue increase.

IV. PROPOSED MODIFICATIONS TO EXISTING TARIFFS

A. Proposed Modification to Calculation of Rider FAC Rates

Q. Describe the Company's proposal to modify the calculation of Rider FAC rates.

A. The Company proposes to use a rolling twelve-month average to calculate the Rider FAC rates rather than the prior month expenses and sales to calculate the rates. The Company proposes to continue its practice of deferring the difference in the actual recoverable Rider FAC expense and the Rider FAC revenues accrued each month to a regulatory asset or liability.[36]

Q. Do you agree with the Company that this proposal will reduce monthly volatility in the Rider FAC rates?

A. Yes. This will significantly reduce the monthly and seasonal volatility in the Rider FAC rates, thus benefitting customers through more consistent and uniform rates throughout the year.

Q. What is your recommendation?

A. I recommend that the Commission adopt the Company's proposal.

B. Proposed Transfer of Capital Costs from Environmental Surcharge Revenues to Base Revenues

Q. Describe the Company's proposal to transfer the recovery of costs from the Rider ESM to base revenues.

A. The Company proposes to transfer the recovery of the return on rate base and the related depreciation and property tax expenses from the ESM revenues to base revenues.[37] The recovery relates specifically to the four capital projects presently

[36] Lawler Testimony at 15.
[37] Spiller Testimony at 4.

included in the ESM.[38] The Company quantified the effects of this proposal on the base revenues at $12.076 million in response to AG and Staff discovery on this issue.[39]

Q. What is the Company's rationale for this proposed transfer to ratemaking recovery from ESM revenues to base revenues?

A. In response to Staff discovery asking the Company to explain why it proposed this transfer to ratemaking recovery from ESM revenues to base revenues, Ms. Lawler states:

> The Company is proposing to incorporate historical plant in service into base rates in this proceeding. The Company believes it is a clean approach to ratemaking to include all historical plant in service in rate base and reset riders at the time new base rates are put into effect so as to reduce the surcharge going forward. However, if the Commission prefers the Company keep the plant in service in Rider ESM, the Company would not oppose that decision.[40]

Q. Is the Company's rationale for this proposed transfer compelling?

A. No. The Company's rationale fails to identify any benefits to its proposal. Although the Company did not define the term "clean approach," the proposal does not simplify the Company's ratemaking process or eliminate the Commission's monthly review of

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[38] Duke Kentucky's response to AG 2-40(c). I have attached a copy of the response as my Exhibit___(LK-6). The four projects are listed on Form 2.10 in the Company's monthly ESM filings. The Company provided the January 2023 filing in response to AG 2-40(a) and the November 2022 filing in response to AG 2-40(b).

[39] Duke Kentucky's responses to AG 2-40 and Staff 3-21. I have attached a copy of the response to Staff 3-21 as my Exhibit___(LK-7).

[40] Duke Kentucky's response to Staff 2-38(b). I have attached a copy of this response as my Exhibit___(LK-8).

the ESM filings, which will continue. The Company's proposal is not so much a rationale, but rather, its description of the result of its proposed transfer.

Q. Is there actually harm to customers that will result from the Company's proposal if it is adopted?

A. Yes. The Company's proposal is not revenue neutral between base rate cases. The required return on the environmental rate base will continue to decline as the plant is depreciated. The decline in this component of the revenue requirement is reflected in the ESM revenues each month, all else equal. This benefits customers, but still provides the Company dollar for dollar recovery, no more and no less. However, if the environmental rate base and related costs are transferred to recovery through base revenues, the recovery will be fixed at the test year level; the recovery will not decline as the underlying costs decline each month. This will harm customers and provide the Company excessive recovery compared to continued recovery through the ESM.

Q. What is your recommendation?

A. I recommend that the Commission deny the Company's request to transfer recovery of the return on rate base and the related depreciation expense and property tax expense from Rider ESM revenues to base revenues. The Company's proposal will harm customers and unduly benefit the Company through excessive base revenue recoveries.

Q. What is the effect of your recommendation?

A. The effect is a reduction of $12.076 million in the base revenue requirement, as previously noted and calculated by the Company. The Company will continue to recover these costs through the ESM revenues, where the Company will recover its actual costs, no more and no less.[41]

The $12.076 million reduction in the Company's requested base rate increase is shown as the first adjustment on the table in the Summary section of Mr. Futral's Direct Testimony. The effects of the subsequent AG adjustments shown on that table are sequential and reflect the prior reductions in rate base, depreciation expense, and property tax expense included in the Company's $12.076 million quantification of the reduction in the base revenue requirement to avoid double counting those effects. Nevertheless, as noted by Mr. Futral, there will be an effect of the subsequent AG recommendations on the ESM revenue requirement related to the return reflected in the weighted average cost of capital. In addition, there will be an effect of lower depreciation expense if my recommendations to lower depreciation rates are authorized.

C. ESM Rates Should Be Reduced to Mitigate Magnitude of Requested Base Rate Increase By Extending East Bend 2 Ash Pond ARO Regulatory Asset Amortization Period

[41] Duke Kentucky's response to AG 2-40(f).

Q. Describe the present recovery of the East Bend 2 ash pond ARO regulatory asset through the ESM.

A. The Company presently recovers the East Bend 2 ash pond ARO regulatory asset through the ESM on a levelized basis over ten years using a weighted average cost of capital rate of return.[42] The present annual recovery is $2.430 million based on the monthly recovery of $0.205 million.[43] The recovery started in June 2018 and will be completed in May 2028.[44]

Q. Was the ten-year amortization period tied to any specific milestone date, such as the probable retirement date of East Bend 2?

A. No. The Company stated in response to AG discovery that "[t]here is not any significance to the May 2028 date other than it is the last month of the ten-year amortization period."[45]

Q. Would an extension of the amortization period for this regulatory asset mitigate the requested increase in this proceeding?

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[42] The recovery schedule is provided in Form 2.20 in the Company's monthly ESM filings. The Company provided the January 2023 filing in response to AG 2-40(a) and the November 2022 filing in response to AG 2-40(b).

[43] *Id.*

[44] *Id.*

[45] Duke Kentucky's response to AG 2-48(e). I have attached a copy of this response as my Exhibit___(LK-9).

A. Yes. An extension of the amortization period for this regulatory asset and others would mitigate the effects of the requested increase in this proceeding, albeit through the ESM revenue requirement. The Commission should take advantage of available ratemaking tools to reduce the sheer magnitude of the Company's requested rate increase in this proceeding.

Q. Would the probable retirement date for East Bend 2 used for depreciation and decommissioning expense provide the basis for an appropriate and reasonable amortization period?

A. Yes. The probable retirement date for East Bend 2 would provide the basis for an appropriate and reasonable amortization period, regardless of whether that probable retirement date is 2041, as I recommend, or 2035, as the Company proposes. In addition, it would be consistent with the amortization period for the East Bend 2 deferred O&M expense regulatory asset if the Commission adopts my recommendation to use the probable retirement date for the amortization of that other East Bend 2 regulatory asset.

Q. What is your recommendation?

A. I recommend that the Commission extend the amortization period and recalculate the levelized recovery to reflect a probable retirement date of mid-year 2041, the probable retirement date reflected in the presently approved depreciation rates for East Bend 2.

Alternatively, if the Commission approves the Company's request to accelerate the probable retirement date for depreciation and decommissioning expense purposes, then I recommend that it extend the amortization period and recalculate the levelized recovery to reflect a probable retirement date of mid-year 2035.

Q. What is the effect of your recommendation?

A. The effect of my primary recommendation is a reduction of $1.463 million in the recovery of this regulatory asset through the ESM revenues.

The effect of my alternative recommendation is a reduction of $1.211 million in recovery of this regulatory asset through the ESM revenues.

V. PROPOSED NEW PROGRAMS, RELATED TARIFFS, AND REGULATORY ASSETS

<u>A. Proposed New Generation Asset True-Up Mechanism</u>

Q. Describe the Company's proposed Rider GTM.

A. The Company proposes a new Rider GTM to recover a return of and on the undepreciated plant costs and other operating expenses (depreciation expense and property tax expense) of its owned generating units after they are retired in the future. Company witness Ms. Sarah Lawler describes the calculation of the Rider GTM revenue requirement as follows.

> The Company proposes to calculate a return on and of the remaining NBV of the generating assets and related assets at the time of retirement. The Company would calculate a revenue requirement to recover a return on the rate base associated with this remaining NBV along with recovery of the associated depreciation expense and any remaining required property tax expenses. Rate base would be calculated as gross plant in-service less accumulated depreciation less accumulated deferred income taxes associated with the plant in-service. Any unrecovered or over recovered cost of removal and other site-related assets would also be included in the net remaining plant in-service balance in the rider. The Company may also propose to recover necessary O&M expenses, if any, in Rider GTM. For example, if groundwater monitoring is required, the Company would propose to include those expenses in the rider.[46]

Initially, the Rider GTM tariff rates will be set at $0. The Company proposes filing procedures that include a filing for each generating unit retirement so that the Rider GTM rates to recover that unit's costs will become effective upon retirement, as well as annual revisions to the GTM tariff rates to reflect changes in those costs. The Company seeks approval for a ten-year amortization of the regulatory asset and a return on the regulatory asset at the weighted average cost of capital approved in its most recent electric base rate case. The Company also seeks authority to create a regulatory asset for the remaining undepreciated net book value at the date of the retirement.

Q. Is there a fundamental flaw in the Company's proposed Rider GTM?

A. Yes. The proposed Rider GTM does not address the ongoing recovery of the costs of

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[46] Lawler Testimony at 18.

the retired generating units through base rates. This is a significant flaw in the Company's proposed Rider GTM and will result in recovery of the same costs once through base revenues and a second time through the Rider GTM unless it is corrected or until base rates are reset. This flaw in the proposed Rider GTM also fails to reflect savings from costs no longer incurred, but still recovered through base revenues, which include, but are not limited to, reductions in non-fuel operation and maintenance expense, administrative and general expense, and other taxes expense.

Q. How should this flaw be corrected?

A. I recommend that the GTM revenue requirement for the generating unit that is retired be reduced by the base revenues that recover the non-fuel costs of that generating unit. This credit would remain in effect until base rates are reset that exclude all costs of the retired generating unit.

I also recommend that the calculation of the credit in Rider GTM follow the base/current method used for the Company's environmental surcharge mechanism, which calculates the revenue requirement for the allowed costs and then subtracts the base revenues that recover some or all of the allowed costs. The base/current method reflects changes in base revenue recovery compared to the test year costs reflected in the base year revenue requirement for changes in actual sales compared to the test year, up or down.

Q. Do the LG&E/KU Retired Asset Recovery Rider tariffs reflect a credit for the base revenue recovery of the non-fuel costs of the retired generating units to ensure there is no double recovery?

A. Yes. The LG&E/KU Retired Asset Recovery Rider tariffs (par 4) require those utilities to subtract the revenue collected through base rates for the current expense month from the retired asset revenue requirement calculated for the current expense month.[47]

Q. Does the Company agree in part with a credit in the Rider GTM for the recovery of non-fuel costs included in base revenues?

A. Yes, but only in part. In response to Staff discovery on this issue of double recovery through both the Rider GTM and base revenues, the Company agreed to reflect a credit in the Rider GTM for "any revenues included in base rates associated with these assets."[48] In response to AG and additional Staff discovery, the Company stated that it "would make [the] necessary calculations in that proceeding [the proceedings after a generating unit retirement to populate the rider and set the rates] to ensure that it does not over or double recover the remaining NBV of the assets in base rates." [49]

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[47] I have attached a copy of the LG&E and KU Retired Asset Recovery Rider tariffs as my Exhibit___(LK-10) and Exhibit___(LK-11), respectively.

[48] Duke Kentucky's response to Staff 2-1(b). I have attached a copy of this response as my Exhibit___(LK-12).

[49] Duke Kentucky's responses to AG 1-92(c) and Staff 2-42. I have attached a copy of each response as my Exhibit___(LK-13).and Exhibit___(LK-14), respectively.

However, this limited concession with respect to the "remaining NBV of the assets in base rates" fails to address any non-fuel operating expenses, other than depreciation expense related to gross plant and income tax expense related to the return on equity. The limited concession fails to address non-fuel operation and maintenance expense, administrative and general expense, including employee benefit/welfare expense, payroll tax expense, and property tax expense. Nor did the Company's response to AG and Staff discovery address the methodology that will be used to calculate the recovery through base revenues.

Q. In contrast to the Company's concession to provide a credit in the GTM for "the remaining NBV of the assets in base rates," does your recommendation address all costs included in base rates and the methodology that should be used to calculate the recovery through base revenues?

A. Yes. In contrast to the Company's limited concession, my recommendation reflects a comprehensive calculation of the credit to the GTM necessary to offset all costs related to the retired generating unit that are recovered through base revenues and establishes the base/current methodology to calculate the credit to offset the recovery through base revenues.

Q. Are there other flaws in the Company's proposed Rider GTM?

A. Yes. The proposed Rider GTM subtracts only the "accumulated deferred income taxes associated with the plant in-service."[50] However, the ADIT associated with the "plant in-service" does not reflect the entirety of the ADIT related to the generating unit after it is retired. It does not include the effects of the Company's deduction from taxable income for the remaining tax basis of that asset. The ADIT subtracted from rate base should be the total ADIT associated with the retired generating unit, consisting of the sum of the ADIT "associated with the plant in-service" and the ADIT associated with the deduction for the remaining tax basis of that asset when that unit is retired and the cost no longer is included in plant in-service. This ADIT should be the same as the ADIT resulting from multiplying the regulatory asset times the combined federal and state income tax rate.

Q. What is your recommendation?

A. I recommend that the Commission modify the proposed Rider GTM so that it subtracts the ADIT related to the regulatory asset calculated using the combined federal and state income tax rate. This methodology is consistent with the calculations reflected in the Kentucky Power Company Decommissioning Rider (DR) authorized in Kentucky Public Service Case No. 2012-00578,[51] and the LG&E and KU Retired

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[50] Lawler Testimony at 18.

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

Asset Recovery Riders (Rider RAR) authorized in Kentucky Public Service Cases No. 2020-00349[52] and 2020-00350,[53] respectively.[54]

Q. Do you agree with the Company's proposed recovery of the remaining undepreciated net book value of each generating unit that is retired over ten years?

A. No. Ten years is an unduly short period of time if the remaining undepreciated net book value is significant. The remaining undepreciated net book value of East Bend 2 as of November 30, 2022, was $483.996 million.[55] Historically, retired plant costs have been recovered by Kentucky utilities over the remaining lives of other operating generating units by rolling in the undepreciated net book value of the retired units as a reduction to the accumulated depreciation for the operating units and including the cost in the calculation of the depreciation rates for those operating units. That is presently the case with the Company's Miami Fort 6 generating unit retired plant costs.

2013).

[52] Case No. 2020-00349, *Electronic Application of Kentucky Utilities Company for an Adjustment of its Electric Rates, A Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit* (Ky. PSC June 30, 2021).

[53] Case No. 2020-00350, *Electronic Application of Louisville Gas and Electric Company for Adjustment of its Electric and Gas Rates, A Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit* (Ky. PSC June 30, 2021).

[54] I have attached a copy of the KPC Decommissioning Rider tariff as my Exhibit___(LK-15). For the LG&E and KU Retired Asset Recovery Rider tariffs, refer to my Exhibit___(LK-10), and Exhibit___(LK-11), respectively.

[55] Duke Kentucky's response to AG 1-23(c). I have attached a copy of this response as my Exhibit___(LK-16).

Although Miami Fort 6 was retired in 2015, the retired plant costs presently are recovered over 26 years (through 2041) through the East Bend 2 depreciation rates and depreciation expense.

More recently, and in lieu of recovery through the depreciation rates and depreciation expense of other operating generating units, the Commission also has allowed recovery of larger dollar retired plant costs through separate riders for Kentucky Power Company and KU/LG&E. For example, the Commission approved twenty-five years for Kentucky Power Company to recover the Big Sandy 2 and Big Sandy 1 coal-fired retired plant costs through the Decommissioning Rider.

Q. What is your recommendation on the recovery period?

A. I recommend that the Commission set the time period at twenty years, but reserve the right to consider whether it should be shorter if the remaining undepreciated net book for each generating unit that is retired is not significant and it would not have an unreasonable impact on customer rates if the costs were recovered over a shorter period. In other words, the presumption would be an amortization period of twenty years, but the utility could request a shorter time period if the remaining undepreciated net book value for a specific generating that is retired is not significant.

Q. Do you agree with the Company's proposed recovery of the remaining undepreciated net book value at the retirement of each generating unit on a

levelized basis?

A. Yes. The levelized recovery provides two significant benefits. First, it results in an initial rate reduction compared to the traditional declining rate base methodology. Second, it provides a uniform recovery each year. Third, it allows the Commission to mitigate the recovery of the cost of the replacement capacity, which typically would be recovered on a declining rate base methodology.

Q. Are there other concerns with the proposed Rider GTM tariff language as drafted by the Company?

A. Yes. First, the draft Rider GTM tariff language is not limited to the East Bend 2 and Woodsdale generating units; it also would apply to the East Bend 1 and Miami Fort 6 generating units already retired, the costs of which are presently recovered in base rates.

The draft Rider GTM tariff language refers to the "Retirement Costs of generating units at the East Bend and Woodsdale generating stations and other site-related retirement costs that will not continue in use." The Company transferred the remaining undepreciated net book value of Miami Fort 6 to the accumulated depreciation reserve for East Bend 2 and presently recovers the remaining undepreciated cost of the retired unit over the remaining depreciable life of East Bend 2 through the East Bend 2 depreciation rates. The "other site-related retirement costs that will not continue in use" language also could apply to future generating units that have not yet been approved or constructed.

Second, the proposed Rider GTM tariff language does not incorporate the procedural aspects of the Company's proposal. This is especially important for the initial calculations as each generating unit is retired and then each future year as the costs of the units decline, such as when the operating expenses decline and then after the recovery of the remaining undepreciated net book value is completed.

Third, the proposed Rider GTM does not address or define the test year that will be used to calculate the Rider GTM revenue requirement. This matters because the rate base and operating expenses in the "current" test year should reflect the forecast year when the Rider GTM tariff rates will be in effect.

Fourth, the proposed Rider GTM does not include a true-up either to the actual revenue requirement for the prior test year or to the actual revenues compared to the forecast revenues for the prior year. This matters because the "current" test year should reflect the forecast year when the Rider GTM tariff rates will be in effect and actual costs and actual revenue recoveries will vary from those that were forecast. The two true-ups are necessary to ensure that customers only pay for the actual prudent and reasonable costs, no more and no less.

Q. What is your recommendation on these concerns with respect to the proposed Rider GTM tariff language issues?

A. I recommend that the Commission limit the applicability of the proposed Rider GTM to East Bend 2 and the existing Woodsdale generating units. The Rider GTM tariff would terminate after the recoveries of those units are completed. If there is a need to extend the tariff to apply to other generating units in the future, then the Commission could modify and extend the tariff at that time.

I recommend that the Commission direct the Company to include the procedural aspects described in Ms. Lawler's Direct Testimony in the Rider GTM tariff language.

I recommend that the Commission direct the Company to calculate the Rider GTM revenue requirement based on the forecast costs during the year the Rider GTM tariff rates will be in effect until they are reset.

I recommend that the Commission direct the Company to include two true-up provisions in the calculation, one for the true-up of the forecast revenue requirement to the actual revenue requirement and the other for the true-up of actual revenues to the actual revenue requirement.

Q. What is your recommendation on the proposed Rider GTM?

A. I recommend that the Commission adopt the proposed Rider GTM, but *only* if it adopts all the modifications that I recommend. With the changes that I recommend, this rider will provide a ratemaking structure that ensures timely rate reductions when each generating unit is retired and allow the Company to recover the actual prudent and reasonable costs of the retired generating units, no more and no less.

<u>B. Proposed New Electric Vehicle Programs And Related Tariffs</u>

Q. Describe the Company's proposed new electric vehicle programs.

A. The Company proposes two new electric vehicle ("EV") programs, two new related tariffs, and related regulatory assets in this proceeding. The new programs provide financial incentives to customers in order to expand the number and use of EVs and accelerate the development of the EV infrastructure necessary to charge those EVs. The Company does not believe that either of these new EV programs require a CPCN from the Commission, although it does seek authorization for the new programs due to its requests for approval of the two new related tariffs and to establish related regulatory assets.

The first of the proposed new EV programs is the Make Ready Credit ("MRC") program. The MRC program is a voluntary program for residential and non-residential customers. Pursuant to this program, the Company will provide bill credits to participating customers to defray the costs of customer or third party owned improvements ("make ready infrastructure") necessary to install Level 2 or higher EV charging equipment. The Company proposes to defer the costs of the MRC program as a regulatory asset and will seek recovery of the regulatory asset in a future rate proceeding. The Company also requests authorization to defer carrying costs on the regulatory asset at the cost of debt approved in this proceeding.[56]

The second of the proposed new EV programs is the Electric Vehicle Supply Equipment ("EVSE") program. The EVSE program is a voluntary program for residential and non-residential customers. Pursuant to this program, the Company will own the EV charging equipment, but will charge participating customers a fee for the use of the EV charging equipment over the term of the contract. Included in that fee is the cost of the equipment, installation, and warranty work. The Company does not plan to include the costs of the EV charging equipment in rate base.

Q. Are these programs mandated by law?

A. No. The programs are discretionary. They are not required by law. Nor is the Company required to provide incentives to subsidize or accelerate the expanded use of EVs or the development of EV infrastructure.

Q. The Company asserts that the proposed MRC program "leverages" its existing line extension program. Do you agree?

A. No. The proposed MRC program and the existing line extension program are significantly different in purpose and the customers who benefit versus those who pay. The Company's existing line extension program requires new customers to pay a

[56] Lawler Testimony at 8.

portion of the cost of the new assets if providing service to the customer is not otherwise economic. The Company, not the new customer, owns the new assets. The line extension program ensures that existing customers are not forced to subsidize the cost of the new assets necessary to serve new customers. The existing line extension program does not provide financial incentives to the new customer.

In contrast to the Company's existing line extension program, the MRC program provides an incentive to existing customers to expand their usage by subsidizing the customer's own EV infrastructure costs. The Company will not own any assets installed by the customer to enable EV charging. Also in contrast to the Company's existing line extension program, the MRC program imposes costs on existing customers in order to subsidize certain existing customers.

Q. What is your recommendation?

A. Although I do not oppose the two proposed programs, there is no compelling reason why the cost or the risk of the MRC program should be socialized and imposed on all ratepayers in a future rate proceeding. Instead, if the Commission believes both programs are beneficial, then I recommend that the MRC program be subsumed into the EVSE program, that all costs of the combined program be recovered exclusively from participating customers, and that none of the revenues and none of the costs be included in the base revenue requirement. If the Commission approves the MRC program as a standalone program, then I recommend that it require the Company to recover the costs exclusively from participating customers. In any event, I recommend that the Commission deny the Company's request for authority to defer the costs of the MRC program for future ratemaking recovery.

C. Proposed New Incremental Local Investment Charge Tariff

Q. Describe the Company's proposed new Rider Incremental Local Investment Charge tariff ("Rider ILIC").

A. The Company proposes Rider ILIC "to recover the costs of incremental processes and system investments required pursuant to a local ordinance or franchise, such as undergrounding of electric facilities or other relocations or system improvements and upgrades that are either requested or required by local regulation that are outside the Company's regular system-wide construction plans."[57]

Ms. Lawler further explains that "[u]pon approval of the tariff and mechanism in this proceeding, Duke Energy Kentucky will file a separate application to implement Rider ILIC as necessary in response to a local government mandate such as an ordinance or franchise. This application would be filed prior to the Company commencing work on the mandated project and subject to Commission determination of reasonableness . . . Going forward, the Company will make annual applications with the Commission to update Rider ILIC, reflecting any new proposed capital projects

[57] *Id*. at 21.

and the depreciation of previously approved capital projects as well as any other necessary data input changes supporting the rider calculation."[58]

Q. Does any Company witness or the proposed Rider ILIC tariff describe how the Company will determine whether the costs of a project are "outside the Company's regular system-wide construction plans"?

A. No. This is extremely problematic. The Company has proposed no objective process by which it or the Commission can ensure that the scope and/or cost of any such projects otherwise would or should be included in the Company's regulatory system-wide construction plans. This is particularly true the more generalized the local ordinance, e.g., upgrade and refresh the downtown streetlighting. The proposed tariff language provides no additional guidance, other than repeating the concept described by Ms. Lawler as follows:

> There shall be a monthly surcharge added to customer bills to recover any incremental costs incurred by the Company as a direct result of a city or other local legislative authority's (Public Authority) ordinance, franchise or other directive including but not limited to distribution, transmission, generation, and other construction and facility costs (Incremental Local Investments) that are outside the Company's regular system-wide construction plans absent the Public Authority's ordinance, franchise, or other directive. The Kentucky Public Service Commission shall determine whether such a charge shall be included on all customer bills or only on those customers within the boundaries of the Public Authority imposing such costs.

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[58] *Id*. at 22.

Q. Does the Company's proposed tariff language requiring an "agreement" between the local government authority and the Company describing the scope of work remedy this fundamental problem?

A. No. Such an "agreement" simply provides a process for the local government authority to agree with the Company that the work is incremental, enter into an "agreement" for the scope of work and cost of that work, and then trigger an increase in the Company's rates to recover the cost of that work, whether imposed on customers only within the boundaries of the local jurisdiction or on all of the Company's customers systemwide.

Q. Does the proposed Rider ILIC include a requirement to file and obtain approval of the "agreement" before construction commences or the rates are implemented based on a calculation by the Company using a levelized fixed charge rate?

A. No. As drafted, the proposed Rider ILIC tariff reflects no requirement to file the "agreement" with the Commission or obtain approval of the "agreement" from the Commission. This is problematic because it essentially delegates the Commission's authority to establish and implement rates to the Company.

Q. Are there other problems with the proposed Rider ILIC?

A. Yes. As drafted, the proposed Rider ILIC tariff not only delegates the Commission's ratemaking authority to the Company, but it provides the local government authority an incentive to issue such an ordinance or directive. As drafted, the only authority that will be retained by the Commission is whether "the charge" will be imposed on only the customers within the boundaries of the local government authority or imposed on all customers systemwide; however, the proposed tariff language fails even to address whether the Commission will make this determination one time or for each "agreement."

In addition, the ratemaking recovery as described in the proposed Rider ILIC tariff appears to be based on the estimated installed costs of the assets before the costs are incurred and construction is completed. Further, the use of a fixed charge rate methodology essentially provides a levelized form of ratemaking recovery, yet the Company will incur the costs for financial statement purposes on a declining cost basis, thus potentially creating an additional base revenue requirement for all customers to pay in future base rate case proceedings.

Q. What is your recommendation?

A. I recommend that the Commission deny the proposed Rider ILIC. It is poorly conceived, provides an alternative form of regulation, indeed effectively self-regulation, and will allow the Company through an "agreement" with a local government authority to establish rates not only within the boundaries of the local government authority, but potentially systemwide.

D. Proposed New Clean Energy Connection Rider ("Rider CEC")

Q. Describe the Company's proposed new Clean Energy Connection program.

A. The Clean Energy Connection ("CEC") Program is a community solar program through which participating customers can voluntarily subscribe to a share of new solar energy facility(s).[59] Under the CEC Program, the Company will seek a CPCN from the Commission and construct discrete solar projects.

The Company's first project under the CEC Program is expected to be a 49 mW facility that could be placed in service as early as 2025.[60] The Company has not yet filed an application for a CPCN for that project; however, it states in this proceeding that it plans to allocate 37 mW to commercial customers, 10 mW to residential customers, and 2 mW to income qualified residential customers.[61]

Q. Describe the Company's proposed ratemaking for the CEC program costs.

A. The Company describes two forms of interrelated ratemaking recovery for the CEC program costs. First, the Company proposes to include the costs of the CEC program in the calculation of the base revenue requirement in future rate proceedings.[62] Second, the Company proposes to recover the costs of the CEC program from

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[59] *Id*. at 9 – 10.
[60] Direct Testimony of Paul Halstead ("Halstead Testimony"), at 6.
[61] *Id*. at 7.
[62] Lawler Testimony at 10 – 11.

participating customers through subscription fee revenues pursuant to the proposed new Rider CEC tariff. The Company proposes to record the subscription revenues as miscellaneous revenues and to use those revenues to reduce the base revenue requirement in future rate proceedings.

Q. How will the subscription fees be calculated pursuant to the proposed Rider CEC tariff?

A. The proposed Rider CEC tariff does not set forth or describe the calculations, other than that there will be subscription fees charged on a $/kW-month basis and bill credits applied on a cents/kWh basis, both of which are differentiated between participating customers and low income participating customers. Company witness Mr. Halstead only generally describes how the subscription fees on a $/kW-month basis will be calculated, but provides no description whatsoever of how the bill credits on a cents/kWh basis will be calculated, other than to describe certain limits on the amount of the bill credits.[63] However, Mr. Halstead does provide illustrative calculation templates of a hypothetical solar facility as confidential exhibits to his testimony, although I note that these templates assume ownership of the hypothetical solar facilities, not a purchased power agreement.[64]

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[63] *Id.* at 12 – 13.
[64] Attachment PLH-2, Confidential DEK CEC Asset Revenue Requirement; and Attachment PLH-3, Confidential DEK Community Solar Program Support.

Q. Does the proposed Rider CEC tariff include any procedural provisions?

A. No. It isn't even clear whether there will be separate tariff rates for participants in separate projects or a single tariff rate for all participants in all projects. However, Mr. Halstead does note that the Company will seek a CPCN for new solar projects and states that the Company will update these values and submit them in conjunction with its solar facility CPCN filing.

Q. What is your recommendation?

A. I recommend that the Commission deny the proposed Rider CEC at this time. The Company should provide a revised and more developed Rider CEC if and when it files its Application for a CPCN for a new solar facility for the Commission's consideration at that time. There is no need for the Commission to consider and resolve all problems with this proposed Rider CEC in this proceeding.

E. Proposed New Comprehensive Hedging Program

Q. Has the Company provided a detailed description of its proposed new comprehensive hedging program?

A. No. The Company only generally describes the proposed program as an expansion of its back-up supply plan that was approved only through May 31, 2022.[65] Although Mr. McClay states that the Company plans to utilize the PJM AD financial forward power markets that have available financial products, no Company witness listed those products or otherwise specifically described how it would use those products to mitigate price volatility or reduce costs.

Q. In its Order in Case 2021-00086, the Commission stated: "Therefore, in its next filing, Duke Kentucky should evaluate whether there is real risk and a need for a back-up power supply plan and provide support whether a back-up power supply plan is necessary. Duke Kentucky should also provide a long-term cost effectiveness analysis of its back-up power supply plans."[66] Did the Company provide evidence that it performed such an evaluation or provide a long-term effectiveness analysis of its back-up power supply plan or its proposed comprehensive hedging program?

A. No.

Q. Without evidence from the Company that it performed such an evaluation and a long-term effectiveness analysis of its back-up power supply plan or its proposed comprehensive hedging program, does the Commission have the information that it

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[65] Direct Testimony of James McClay ("McClay Testimony"), at 15 – 21. The Commission last approved the Company's backup supply plan in Case 2021-00086.

[66] Case No. 2021-00086, *Electronic Back-Up Power Supply Plan of Duke Energy Kentucky, Inc.* (Ky. PSC Nov. 30, 2021), Order at 7.

found necessary in Case 2021-00086 to make an informed assessment of the Company's proposed new comprehensive hedging program in this proceeding?

A. No. The Commission should direct the Company to file a separate case concerning its proposed backup power supply plan and/or comprehensive hedging program, and the required evaluation and long-term effectiveness analysis in that filing, so that it can make an informed assessment. To the extent that such a plan may benefit customers, the Commission should direct the Company to do so expeditiously.

Q. Does this complete your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR (1) AN ADJUSTMENT OF ELECTRIC RATES; (2) APPROVAL OF NEW TARIFFS; (3) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (4) ALL OTHER REQUIRED APPROVALS AND RELIEF	)	**CASE NO. 2022-00372**

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

OFFICE OF THE ATTORNEY GENERAL OF THE COMMONWEALTH OF KENTUCKY

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

MARCH 10, 2023

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)

Chartered Global Management Accountant (CGMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

Society of Depreciation Professionals

Mr. Kollen has more than forty 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.

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
City of Austin
Georgia Public Service Commission Staff
Florida Office of Public Counsel
Indiana Office of Utility Consumer Counsel
Kentucky Office of Attorney General
Louisiana Public Service Commission
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York City
New York State Energy Office
South Carolina Office of Regulatory Staff
Texas Office of Public Utility Counsel
Utah Office of Consumer Services

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 December 2022**

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.
2/88	10064	KY	Kentucky Industrial Utility	Louisville Gas &	Revenue requirements, O&M expense, capital

Expert Testimony Appearances
of
Lane Kollen
As of December 2022

Date	Case	Jurisdict.	Party	Utility	Subject
			Customers	Electric Co.	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.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.

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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.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.

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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	8469	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.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.

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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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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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.
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.

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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.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735 Rebuttal	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.

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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.
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.
7/99	U-23358	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.

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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.
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.

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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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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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.
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	GA	Georgia Public Service	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization,

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Date	Case	Jurisdict.	Party	Utility	Subject
	Panel with Victoria Taylor		Commission Adversary Staff		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 (Subdocket B)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
05/07	ER07-682-000 Supplemental 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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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 Answer	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.

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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.
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.

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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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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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.
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 Rebuttal 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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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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.
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 Direct and Answering	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	Union Pacific 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	Union Pacific 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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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 03/16 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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
07/16	160021-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Revenue requirements, including capital recovery, depreciation, ADIT.
07/16	16-057-01	UT	Office of Consumer Services	Dominion Resources, Inc. / Questar Corporation	Merger, risks, harms, benefits, accounting.
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	Next Era acquisition of Oncor; 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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
08/17	17-0296-E-PC	WV	West Virginia Energy Users Group	Monongahela Power Company, The Potomac Edison Power Company	ADIT, OPEB.
10/17	2017-00179	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Weather normalization, Rockport lease, O&M, incentive compensation, depreciation, income taxes.
10/17	2017-00287	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Fuel cost allocation to native load customers.
12/17	2017-00321	KY	Attorney General	Duke Energy Kentucky (Electric)	Revenues, depreciation, income taxes, O&M, regulatory assets, environmental surcharge rider, FERC transmission cost reconciliation rider.
12/17	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	Vogtle 3 and 4 economics, tax abandonment loss.
01/18	2017-00349	KY	Kentucky Attorney General	Atmos Energy Kentucky	O&M expense, depreciation, regulatory assets and amortization, Annual Review Mechanism, Pipeline Replacement Program and Rider, affiliate expenses.
06/18	18-0047	OH	Ohio Energy Group	Ohio Electric Utilities	Tax Cuts and Jobs Act. Reduction in income tax expense; amortization of excess ADIT.
07/18	T-34695	LA	LPSC Staff	Crimson Gulf, LLC	Revenues, depreciation, income taxes, O&M, ADIT.
08/18	48325	TX	Cities Served by Oncor	Oncor Electric Delivery Company	Tax Cuts and Jobs Act; amortization of excess ADIT.
08/18	48401	TX	Cities Served by TNMP	Texas-New Mexico Power Company	Revenues, payroll, income taxes, amortization of excess ADIT, capital structure.
08/18	2018-00146	KY	KIUC	Big Rivers Electric Corporation	Station Two contracts termination, regulatory asset, regulatory liability for savings
09/18 10/18	20170235-EI 20170236-EU Direct Supplemental Direct	FL	Office of Public Counsel	Florida Power & Light Company	FP&L acquisition of City of Vero Beach municipal electric utility systems.

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Date	Case	Jurisdict.	Party	Utility	Subject
09/18 10/18	2017-370-E Direct 2017-207, 305, 370-E Surrebuttal Supplemental Surrebuttal	SC	Office of Regulatory Staff	South Carolina Electric & Gas Company and Dominion Energy, Inc.	Recovery of Summer 2 and 3 new nuclear development costs, related regulatory liabilities, securitization, NOL carryforward and ADIT, TCJA savings, merger conditions and savings.
12/18	2018-00261	KY	Attorney General	Duke Energy Kentucky (Gas)	Revenues, O&M, regulatory assets, payroll, integrity management, incentive compensation, cash working capital.
01/19	2018-00294 2018-00295	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas & Electric Company	AFUDC v. CWIP in rate base, transmission and distribution plant additions, capitalization, revenues generation outage expense, depreciation rates and expenses, cost of debt.
01/19	2018-00281	KY	Attorney General	Atmos Energy Corp.	AFUDC v. CWIP in rate base, ALG v. ELG depreciation rates, cash working capital, PRP Rider, forecast plant additions, forecast expenses, cost of debt, corporate cost allocation.
02/19 04/19	UD-18-17 Direct Surrebuttal and Cross-Answering	New Orleans	Crescent City Power Users Group	Entergy New Orleans, LLC	Post-test year adjustments, storm reserve fund, NOL ADIT, FIN48 ADIT, cash working capital, depreciation, amortization, capital structure, formula rate plans, purchased power rider.
03/19	2018-00358	KY	Attorney General	Kentucky American Water Company	Capital expenditures, cash working capital, payroll expense, incentive compensation, chemicals expense, electricity expense, water losses, rate case expense, excess deferred income taxes.
03/19	48929	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Company LLC, Sempra Energy, Sharyland Distribution & Transmission Services, L.L.C.., Sharyland Utilities, L.P.	Sale, transfer, merger transactions, hold harmless and other regulatory conditions.
06/19	49421	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Prepaid pension asset, accrued OPEB liability, regulatory assets and liabilities, merger savings, storm damage expense, excess deferred income taxes.
07/19	49494	TX	Cities Served by AEP Texas	AEP Texas, Inc.	Plant in service, prepaid pension asset, O&M, ROW costs, incentive compensation, self-insurance expense, excess deferred income taxes.
08/19	19-G-0309 19-G-0310	NY	New York City	National Grid	Depreciation rates, net negative salvage.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/19	42315	GA	Atlanta Gas Light Company	Public Interest Advocacy Staff	Capital expenditures, O&M expense, prepaid pension asset, incentive compensation, merger savings, affiliate expenses, excess deferred income taxes.
10/19	45253	IN	Duke Energy Indiana	Office of Utility Consumer Counselor	Prepaid pension asset, inventories, regulatory assets and labilities, unbilled revenues, incentive compensation, income tax expense, affiliate charges, ADIT, riders.
12/19	2019-00271	KY	Attorney General	Duke Energy Kentucky	ADIT, EDIT, CWC, payroll expense, incentive compensation expense, depreciation rates, pilot programs
05/20	202000067-EI	FL	Office of Public Counsel	Tampa Electric Company	Storm Protection Plan.
06/20	20190038-EI	FL	Office of Public Counsel	Gulf Power Company	Hurricane Michael costs.
07/20 09/20	PUR-2020-00015 Direct Surrebuttal	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Coal Amortization Rider, storm damage, prepaid pension and OPEB assets, return on joint-use assets.
07/20 09/20	2019-226-E Direct Surrebbutal	SC	Office of Regulatory Staff	Dominion Energy South Carolina	Integrated Resource Plan.
10/20	2020-00160	KY	Attorney General	Water Service Corporation of Kentucky	Return on rate base v. operating ratio.
10/20	2020-00174	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Rate base v. capitalization, Rockport UPA, prepaid pension and OPEB, cash working capital, incentive compensation, Rockport 2 depreciation expense, EDIT, AMI, grid modernization rider.
11/20 12/20	2020-125-E Direct Surrebuttal	SC	Office of Regulatory Staff	Dominion Energy South Carolina	Summer 2 and 3 cancelled plant and transmission cost recovery; TCJA; regulatory assets.
12/20	2020172-EI	FL	Office of Public Counsel	Florida Power & Light Company	Hurricane Dorian costs.
12/20	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	VCM23, Vogtle 3 and 4 rate impact analyses.
02/21 04/21	2019-224-E 2019-225-E Direct Surrebuttal	SC	Office of Regulatory Staff	Duke Energy Carolinas, LLC, Duke Energy Progress, LLC	Integrated Resource Plans.
03/21	51611	TX	Steering Committee of Cities Served by Oncor	Sharyland Utilities, L.L.C.	ADIT, capital structure, return on equity.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/21	2020-00349 2020-00350	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company and Louisville Gas and Electric Company	Rate base v. capitalization, retired plant costs, depreciation, securitization, staffing + payroll, pension + OPEB, AMI, off-system sales margins.
04/21 Direct 07/21	18-857-EL-UNC 19-1338-EL-UNC 20-1034-EL-UNC 20-1476-EL-UNC Supplemental Direct	OH	The Ohio Energy Group	First Energy Ohio Companies	Significantly Excessive Earnings Test; legacy nuclear plant costs.
05/21 06/21	2021-00004 Direct Supplemental Direct	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	CPCN for CCR/ELG Projects at Mitchell Plant.
06/21	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	VCM24, Vogtle 3 and 4 rate impact analyses.
06/21	2021-00103	KY	Attorney General and Nucor Steel Gallatin	East Kentucky Power Cooperative, Inc.	Revenues, depreciation, interest, TIER, O&M, regulatory asset.
07/21 08/21 10/21	U-35441 Direct Cross-Answering Surrebuttal	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Company	Revenues, O&M expense, depreciation, retirement rider.
09/21	2021-00190	KY	Attorney General	Duke Energy Kentucky	Revenues, O&M expense, depreciation, capital structure, cost of long-term debt, government mandate rider.
09/21	43838	GA	Public Interest Advocacy Staff	Georgia Power Company	Vogtle 3 base rates, NCCR rates; deferrals.
09/21	2021-00214	KY	Attorney General	Atmos Energy Corp.	NOL ADIT, working capital, affiliate expenses, amortization EDIT, capital structure, cost of debt, accelerated replacement Aldyl-A pipe, PRP Rider, Tax Act Adjustment Rider.
12/21	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	VCM24, Vogtle 3 and 4 rate impact analyses.
01/22	2021-00358	KY	Attorney General	Jackson Purchase Energy Corporation	Revenues, nonrecurring expenses, normalized expenses, interest expense, TIER.
01/22	2021-00421	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Proposed Mitchell Plant Operations and Maintenance and Ownership Agreements; sale of Mitchell Plant interest.

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Date	Case	Jurisdict.	Party	Utility	Subject
02/22	2021-00481	kY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Proposed Liberty Utilities, Inc. acquisition of Kentucky Power Company; harm to customers; conditions to mitigate harm.
03/22	2021-00407	KY	Attorney General	South Kentucky Rural Electric Cooperative Corporation	Revenues, interest income, interest expense, TIER, payroll.
03/22 04/22	U-36190 Direct Cross-Answering	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC	Certification of solar resources.
05/22	20200241-EI 20210078-EI 20210079-EI	FL	Office of Public Counsel	Florida Power & Light Company, Gulf Power Company	Hurricanes Sally, Zeta, Isaias; Tropical Storm Eta, pre-planning, restoration and repair, costs, ratemaking recovery.
05/22	U-36268	LA	Louisiana Public Service Commission Staff	1803 Electric Cooperative, Inc.	Wholesale power contracts, wholesale rate tariffs, wholesale rates.
06/22	20220048-EI 20220049-EI 20220050-EI 20220051-EI	FL	Office of Public Counsel	Tampa Electric Company, Florida Public Utilities Company, Duke Energy Florida, LLC, Florida Power & Light Company	Storm Protection Plans. prudence, reasonableness, cost recovery, including deferred return on CWIP.
06/22	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	VCM24, Vogtle 3 and 4 rate impact analyses.
07/22	S-36267	LA	Louisiana Public Service Commission Staff	1803 Electric Cooperative, Inc.	Non-opposition to establish revolving LOC and supporting guarantees by member cooperatives.
08/22	53601	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Company, LLC	Vendor financing, customer advances, cash working capital, ADFIT and temporary differences, depreciation expense, amortization expense.
09/22	20220010-EI	FL	Office of Public Counsel	Tampa Electric Company, Florida Public Utilities Company, Duke Energy Florida, LLC, Florida Power & Light Company	Storm Protection Plan, Cost Recovery Clause, prudence, reasonableness, deferred return on CWIP.
10/22	5-UR-110	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Levelized recovery of retired plan costs, securitization financing.
10/22	2022-00283	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Rockport deferrals and recoveries.
12/22	2022-00263	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Fuel adjustment clause methodology and disallowances.

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Date	Case	Jurisdict.	Party	Utility	Subject

EXHIBIT ____ (LK-2)

Duke Energy Kentucky
Case No. 2022-00372
Attorney General's First Set Data Requests
Date Received: January 11, 2023

AG-DR-01-093

REQUEST:

Refer to the Steinkuhl Testimony at 13, regarding the sales of receivables to an affiliate, Cinergy Receivables, L.L.C., at a discount.

a. Describe the formula in greater detail upon which the discount is calculated and provide as examples the discounts computed for June 2022 and September 2022. Provide in electronic format with all formulas intact.

b. Provide a copy(ies) of all current agreements between the Company and Cinergy Receivables, L.L.C regarding the sales of accounts receivables.

c. Describe in detail the timing of the Company's receipt of cash from Cinergy Receivables, L.L.C. from the date when it transfers the receivables or the right to recover the receivables to Cinergy Receivables, L.L.C.

RESPONSE:

a. The discount for Sale of Accounts Receivable has numerous components and is calculated monthly. The different experiences of the sellers to Cinergy Receivables results in different rates for each utility. The discount is intended to approximate a "Reasonable Equivalent Value Adjustment as if these were sold to a third party. It is important to note that these discounts are applied to the subsequent month's sales; December's sales will be valued using November's data.

DISCOUNT RATE FORMULA:

$$1 - \frac{(1 - B + L - C)}{1 + (D \times T)}$$

Where:

Variable	**Definition**	**Calculation Methodology**	**Notes**
B	Net Charge-Off Adjustment	Three Year Average Net Charge Off as a % of Billings	Net Charge Offs Over 12 Months Divided by 9 Month Lagging Billings over 12 Months; weighted evenly over the three years
L	Late Charge Premium	Three-Year Average of Late Charges Received as a % of Billings	Weighted evenly over the three years
C	Collection Charge	Estimated Collection costs as a % of Billings	25 Basis Points
D	Discount Rate (%)	Discount Rate = LIBOR + 100 Basis Points	
T	Three-Year Average Turnover Rate	Three-Year Average Turnover Rate	Turnover % = (A/R Balance + Unbilled Receivables) / (Current Billings * 12); Weighted evenly over 3 years.

Please refer to AG-DR-01-0158 Attachment A for the underlying data and calculation for the discounts for January 2019 through December 2022.

b. Please refer to AG-DR-01-093 Attachment 1 and AG-DR-01-093 Attachment 2 for the contracts and subsequent amendments related to the receivable facility.

The Company sells nearly all its retail receivables to CRC and they serve to collateralize the notes payable the conduits have issued. To the extent that the amount of accounts receivable exceeds the $350M borrowing capacity of the receivable facility, there is no additional cash passing between the entities. The amount of account receivables that exceeds the borrowing capacity is maintained in a note receivable on the utilities' books. When the utilities are collectively unable to secure the borrowing of the conduits, a paydown of the note payable is processed. This last occurred in April of 2021. Once receivable balances are sufficient to secure the full amount of the borrowing, the facility is once again fully drawn down.

PERSON RESPONSIBLE: Danielle L. Weatherston

EXHIBIT ____ (LK-3)

AG-DR-01-094

REQUEST:

Refer to the Direct Testimony of Danielle L. Weatherston ("Weatherston Testimony") at 4 – 5, regarding the accounting treatment for the sales of receivables to Cinergy Receivables Company ("CRC").

a. Provide a copy of all journal entries for each account/subaccount applicable to the sale of receivables by the Company to CRC and the subsequent receipt of cash received from CRC for the year 2021.

b. Indicate how many times typically each month the Company sells receivables to CRC and also how often journal entries are made to reflect those sales. In addition, describe all subaccounts used in that process.

c. Indicate how many times typically each month the Company records cash receipts from customer accounts and credits the receivables account from CRC, account 145. In addition, describe all subaccounts used in that process.

d. Explain the entire process of what happens and what is recorded by each entity, the Company and CRC, each time a customer makes payment towards the receivable balance. Describe in the response the timing of the sales, the discount for financing costs, the discount for bad debt expense, and any other discounts that reduce the proceeds when the receivables are sold.

e. Refer to the balance sheet comparison included on Schedule B-8 in the Company's application. Identify the applicable asset description for the amounts recorded in account 145 related to the sales of receivables to CRC.

RESPONSE:

a. Please see AG-DR-01-094 Attachment 1 for the journal entries posted in 2021 for the sale of accounts receivable.

b. Refer to Section 2.2 of the Purchase and Sale Agreement in AG-DR-01-093 Attachment 2. The Company sells receivables to CRC on a daily basis. Once per month, during the accounting close process, journal entries are recorded to reflect the total amount of sales of the accounts receivable for the month. Accounts that are included in the transactions include the following:

Account	Account Description Long
0131155	Cash PNC 0659
0142891	IC Customer AR Sold VIE
0144100	SCHM Uncollectible Accr Elec
0145891	IC Note Rec VIE
0146000	AR Intercompany Crossbill
0173891	IC Unbilled AR Sold VIE
0232892	AP Miscellaneous
0419891	IC Int Income VIE
0426509	Loss on Sale of A/R
0426591	I/C - Loss on Sale of A/R
0426891	IC Sale of AR Fees VIE
0450100	Late Pmt and Forf Disc
0487001	Discounts Earn/Lost-Gas
0903891	IC Collection Agent Revenue

c. Cash is received daily and posted to customer accounts. Changes to the 145 Intercompany Note Receivable account are calculated and recorded monthly, as part of the journal entry recording the sale of accounts receivable transaction.

d. Refer to Sections 2.2 and 2.3 of the Purchase and Sale Agreement in AG-DR-01-093 Attachment 2 for additional information related to the sale of receivables to

CRC. Refer to Sections 3.1 and 3.2 of the Purchase and Sale Agreement in AG-DR-01-093 Attachment 2 for additional information related to cash collections.

The Company sells at a discount and without recourse, nearly all its retail receivables to CRC on a daily basis. Journal entries are recorded on a monthly basis. This process is completed in a number of steps. Initially, for Duke Energy Kentucky, the sale of receivables is recorded which entails recording contra amounts to the 142 and 173 accounts, recording the loss on the sale of accounts receivable, negating any late payment revenue recorded, and adjusting the intercompany note receivable from CRC. Charge-offs are transferred to CRC as well. Additionally, the Company earns collection agent revenue and interest income on the intercompany note receivable.

In a parallel fashion, CRC will record the purchase of the accounts receivable by adjusting the receivables and associated discount on their books. This is offset to an intercompany note payable. CRC will record any charge-offs and recoveries. CRC records labor expense based on default labor allocations of various staff that is calculated and billed to CRC. CRC accrues interest on the intercompany note payable. Another source of interest expense is the amounts paid to the lending banks. The utilities transfer cash to CRC to disburse for the interest costs, along with the labor.

Occasionally, the utilities will not have generated enough receivables to secure the entire borrowing. In such an instance, cash will be sent to CRC from the participating utilities, and the intercompany note receivable will be reduced. Once the receivables are again at a sufficient level to securitize the entire borrowing, the cash will be sent to the utility from CRC. This rather infrequent occurrence was last recorded in April 2021.

e. The intercompany note receivable is included in the line item labelled

"Notes Receivable from Associated Companies".

PERSON RESPONSIBLE: Danielle L. Weatherston

EXHIBIT ____ (LK-4)

Duke Energy Kentucky
Case No. 2022-00372
Attorney General's Second Set Data Requests
Date Received: February 16, 2023

AG-DR-02-049

REQUEST:

Refer to Duke Kentucky's response to the Attorney General's First Request, Item 94(b), which states that the Company "sells receivables to CRC on a daily basis," and the Company's response to the Attorney General's First Request, Item 94(c), which states that "[c]ash is received daily and posted to customer accounts."

a. Specifically describe and quantify the number of days from the day the Company "sells its receivables to CRC" to the day the Company receives the cash from that sale, assuming that the Company and other Duke utilities are not required to send or return cash to CRC under the circumstances described in the last paragraph of Duke Kentucky's response to the Attorney General's First Request, Item 94(d). Provide the Company's calculation used to quantify the number of days in response to this request.

b. Confirm that the Company maintains a daily cash balance register or some other form or recordation that reflects cash received from the sale of its receivables to CRC regardless of whether the journal entries reflecting the net receivables transactions are recorded only one time per month (see Duke Kentucky's response to the Attorney General's First Request, Item 94(d)).

c. Provide a schedule in Excel live format for each day in the month of January 2022 that tracks the sale of the Company's receivables to CRC and the receipt of the related cash from CRC, showing the date and amount of the receivables sold to CRC on that date, the date and amount the related cash was received from CRC for each such sale, and the amount of the cash retained by CRC for each such sale by cost component to cover the costs incurred by CRC for bad debt expense, interest expense, and other costs. Calculate the number of days lag from the sale to the receipt of cash for each day's sales to CRC and an average for the month.

d. Confirm that the rationale for the sale of receivables to CRC is to accelerate the availability of cash from customer billings through CRC short term borrowings using the receivables sold by the Company to CRC as collateral for those borrowings. If not confirmed, explain the response in detail.

RESPONSE:

a. Transactions are structured in a way that there is not a daily transfer of funds for the days billings, nor is there a transfer of amounts collected. Amounts of daily billings and cash collections are aggregated and recorded monthly, in accordance with our normal billing processes. CRC's funds availability is limited to its borrowing capacity of $350 million. To the extent that it purchases receivables and is unable to pay for them, a subordinated note to the utilities is adjusted. Occasionally the receivables from the utilities are inadequate to fully collateralize the loans that CRC maintains. In these instances, cash is provided to CRC so they are able to pay down their debt. The debt is again fully drawn once receivables are adequate. This last happened in April of 2021.

b. Please refer to (a).

c. Please refer to (a).

d. The sale of receivables does not provide faster access to cash. It differs from a more traditional factoring arrangement. Rather, a cash influx was received upon the establishment of the receivables facility. This cash was available to CRC from their banking partners who had issued commercial paper to fund the transaction. The sale of receivables to CRC provides ongoing collateral to support this low cost debt.

PERSON RESPONSIBLE: Danielle L. Weatherston

EXHIBIT ____ (LK-5)

KROGER-DR-01-005

REQUEST:

Refer to the direct testimony of Sarah E. Lawler, pp. 5-6. *"East Bend is now currently projected to retire in 2035, six years earlier than its originally planned retirement date of 2041. In order to align the depreciation rates with this new estimated retirement date, depreciation expense has to increase. This is driving approximately $11 million of the total $35 million increase in depreciation expense. Partially mitigating this increase is the fact that the estimated retirement date of Woodsdale is now projected to be 2040, eight years later than its originally planned retirement date. Included in the $35 million increase in depreciation expense is an approximately $7 million decrease associated with this extension of useful life."*

a. Please provide all workpapers in Excel format documenting the change in depreciation expense that would result from the Company's filed case.

RESPONSE:

Please see KROGER-DR-01-005 Attachment which contains depreciation calculations for East Bend (Steam Production accounts) and Woodsdale (Other Production accounts) which sets forth the result of changing the proposed retirement dates from the Depreciation Study (2035 for East Bend and 2040 for Woodsdale) with the previous retirement dates (2041 and 2032, respectively). These new calculations compared to the Depreciation Study result in a decrease of annual depreciation expense for East Bend and an increase for Woodsdale.

It should be noted that changing the retirement dates can create changes in weighted net salvage, distribution of the book reserve, and forecasted interim and terminal retirements. The comparison provided in this response reflects changes to some of these factors.

PERSON RESPONSIBLE: John J. Spanos

DUKE ENERGY KENTUCKY

SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2021

	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2021	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
	STEAM PRODUCTION PLANT										
3110	STRUCTURES AND IMPROVEMENTS	06-2041	85-S1	*	(12)	183,717,638.42	46,934,083	158,829,672	8,244,218	4.49	19.3
3120	BOILER PLANT EQUIPMENT	06-2041	45-S0.5	*	(12)	545,368,156.24	298,832,215	311,980,120	17,461,319	3.20	17.9
3123	BOILER PLANT EQUIPMENT - SCR CATALYST	06-2041	10-S2.5	*	0	7,984,157.58	5,266,747	2,717,411	471,763	5.91	5.8
3140	TURBOGENERATOR UNITS	06-2041	40-S0.5	*	(12)	109,285,792.05	59,323,750	63,076,337	3,736,806	3.42	16.9
3150	ACCESSORY ELECTRIC EQUIPMENT	06-2041	65-R2.5	*	(12)	48,173,349.90	33,908,388	20,045,764	1,058,205	2.20	18.9
3160	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2041	55-S0	*	(12)	23,997,105.75	11,357,282	15,519,476	859,968	3.58	18.0
	TOTAL STEAM PRODUCTION PLANT					918,526,199.94	455,622,465	572,168,780	31,832,279		
	OTHER PRODUCTION PLANT										
3410	STRUCTURES AND IMPROVEMENTS	06-2032	60-R4	*	(5)	36,379,260.23	27,885,105	10,313,118	1,000,447	2.75	10.3
3420	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2032	45-S1.5	*	(5)	61,310,889.91	6,744,645	57,631,789	5,577,093	9.10	10.3
3430	PRIME MOVERS	06-2032	25-S0	*	(5)	10,340,709.70	1,522,502	9,335,243	973,278	9.41	9.6
3440	GENERATORS	06-2032	40-S0.5	*	(5)	211,248,425.04	137,426,306	87,384,540	8,903,824	4.21	9.5
3450	ACCESSORY ELECTRIC EQUIPMENT	06-2032	35-S1	*	(5)	19,858,901.69	12,312,595	8,539,252	928,405	4.68	9.2
3460	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2032	45-R1.5	*	(5)	5,152,109.78	3,329,034	2,080,681	209,824	4.07	9.9
	TOTAL OTHER PRODUCTION PLANT					344,290,296.35	189,220,187	175,284,623	17,592,871		

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

EXHIBIT ____ (LK-6)

AG-DR-02-040

REQUEST:

Refer to the Spiller Testimony at 4, regarding the proposed roll in of rate base included in the environmental surcharge mechanism ("Rider ESM") into base rates.

a. Provide an electronic copy of Duke Kentucky's most recent environmental surcharge filing with the Commission in electronic format with all formulas intact. Duke Kentucky's Environmental Surcharge Reports are not accessible in the Commission's public records.

b. Provide a copy of Duke Kentucky's Environmental Surcharge Report filed with the Commission on December 16, 2022, for the expense month of November 2022. Duke Kentucky's Environmental Surcharge Reports are not accessible in the Commission's public records.

c. Refer to the Environmental Surcharge Report filed with the Commission on December 16, 2022, for the expense month of November 2022, and specifically to the list of capital projects and costs incurred as reflected on ES Form 2.10. Confirm that these are the only plant-related projects that were rolled into the projected rate base amounts in the Company's pending Application. If not confirmed, explain the response in detail.

d. Refer to the Environmental Surcharge Report filed with the Commission on December 16, 2022, for the expense month of November 2022, and specifically to the list of capital projects and costs incurred as reflected on ES Form 2.10. Confirm that all of these capital projects have been completed. If not confirmed, explain the response in detail.

e. Confirm that the recovery of costs through Rider ESM is done so using quantifications from historic period costs and not projected costs. If not confirmed, explain why not in detail.

f. Indicate whether the reduction in the Rider ESM recovery will be concurrent with the corresponding increase in base rates related to the roll in. If not, explain the response in detail.

g. Provide a calculation of the Rider ESM costs that have been included in the Company's projected test year revenue requirement showing all components of rate base (plant in service, accumulated depreciation, accumulated deferred income taxes ("ADIT"), other), all components of the return on rate base, all separate operating expenses, and any related gross-ups. In addition, provide citations to the Application schedules in which each of the various components of the cost of service were included.

h. Provide copies of all workpapers used to convert, or roll-forward, all historic costs included in the Rider ESM to the projected amounts in the test year, such as changes to the level of accumulated depreciation and ADIT.

RESPONSE:

a. Please see AG-DR-02-040 Attachment 1 for an electronic copy of Duke Energy Kentucky's most recent environmental surcharge filing with the Commission in electronic format with all formulas intact.

b. Please see AG-DR-02-040 Attachment 2 for a copy of Duke Energy Kentucky's Environmental Surcharge Report filed with the Commission on December 16, 2022, for the expense month of November 2022.

c. Confirmed. The capital projects listed on ES Form 2.10 are the only plant-related projects that were rolled into the projected rate base amounts in the Company's pending Application.

d. Confirmed. All of the capital projects on ES Form 2.10 have been completed.

e. Confirmed. The recovery of costs through Rider ESM is done so using quantifications from historic period costs and not projected costs.

f. The reduction in the Rider ESM recovery will be concurrent with the corresponding increase in base rates related to the roll in.

g. Please see AG-DR-02-040 Attachment 3, page 1, for a calculation of the Rider ESM costs that have been included in the Company's projected test year revenue requirement including citations to the Application schedules in which each of the various components of the cost of service were included.

h. Please see AG-DR-01-112 Attachment 1 and AG-DR-01-112 Attachment 2 for the roll forward of the historic gross plant and accumulated depreciation reserve balances included in the Rider ESM to the projected amounts as of June 2023. Please see AG-DR-02-040 Attachment 3, page 2, for the roll forward of the projected June 2023 gross plant and accumulated depreciation reserve balances to the projected June 2024 balances. Please see AG-DR-02-040 Attachment 3, page 3, for the roll forward of the projected ADIT balances.

PERSON RESPONSIBLE: Lisa D. Steinkuhl

EXHIBIT ____ (LK-7)

STAFF-DR-03-021

REQUEST:

Refer to the response to Staff's Second Request, Item 38b. Provide the adjustment necessary to remove the proposed base rate roll in of plant in service related to Rider Environmental Surcharge Mechanism.

RESPONSE:

Please see STAFF-DR-03-021 Attachment for the adjustment necessary to remove the proposed base rate roll in of plant in service related to Rider Environmental Surcharge Mechanism. The adjustment will reduce rate base by $53,795,072, increase operating income by $5,002,128 and reduce the revenue deficiency by $12,075,851. Please see AG-DR-02-040 Attachment 3 for the support of the adjustments.

PERSON RESPONSIBLE: Lisa D. Steinkuhl

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2022-00372
OVERALL FINANCIAL SUMMARY
FOR THE TWELVE MONTHS ENDED JUNE 30, 2024

SCHEDULE A
PAGE 1 OF 1

LINE NO.	DESCRIPTION	SUPPORTING SCHEDULE REFERENCE	FORECASTED PERIOD	ADJUSTMENT TO REMOVE PROPOSED ESM BASE RATE ROLL IN	FORECASTED PERIOD W/O ESM
1	Rate Base	B-1	1,176,674,865	($53,795,072)	$1,122,879,793
2	Operating Income	C-2	32,212,101	5,002,128	$37,214,229
3	Earned Rate of Return (Line 2 / Line 1)		2.738%		3.314%
4	Rate of Return	J-1	7.526%		7.526%
5	Required Operating Income (Line 1 x Line 4)		88,556,550	(4,048,617)	84,507,933
6	Operating Income Deficiency (Line 5 - Line 2)		56,344,449	(9,050,745)	47,293,704
7	Gross Revenue Conversion Factor	H	1.3342383		1.3342383
8	Revenue Deficiency (Line 6 x Line 7)		75,176,922	(12,075,851)	63,101,071

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2022-00372
JURISDICTIONAL RATE BASE SUMMARY
AS OF JUNE 30, 2024

SCHEDULE B-1
PAGE 1 OF 1

LINE NO.	RATE BASE COMPONENT	SUPPORTING SCHEDULE REFERENCE	13 MONTH AVG. FORECAST PERIOD	ADJUSTMENT TO REMOVE PROPOSED ESM BASE RATE ROLL IN	13 MONTH AVG. FORECAST PERIOD W/O ESM
1	Adjusted Jurisdictional Plant in Service	B-2	$2,247,062,477	(67,432,275)	2,179,630,202
2	Accumulated Depreciation and Amortization	B-3 / B-3.2	($863,836,939)	(8,686,596)	(855,150,343)
3	Net Plant in Service (Line 1 + Line 2)		$1,383,225,538	(58,745,679)	1,324,479,859
4	Construction Work in Progress	B-4	$0		
5	Cash Working Capital Allowance	B-5	$5,424,742		$5,424,742
6	Other Working Capital Allowances	B-5	$45,233,909		$45,233,909
7	Other Items:				
8	Customers' Advances for Construction	B-6	$0		
9	Investment Tax Credits	B-6	$0		
10	Deferred Income Taxes	B-6	($205,889,990)	(4,950,607)	($200,939,383)
11	Excess ADIT	B-6	($51,319,334)		($51,319,334)
12	Other Rate Base Adjustments				
13	Jurisdictional Rate Base (Line 3 through Line 12)		$1,176,674,865	($53,795,072)	$1,122,879,793

EXHIBIT ____ (LK-8)

STAFF-DR-02-038

REQUEST:

Refer to the Direct Testimony of Lisa D. Steinkuhl (Steinkuhl Direct Testimony), page 16, line 14 through page 17, line 2.

a. Refer to KRS 278.183, Section 2, which states, in relevant part, "Recovery of costs … that are not already included in existing rates shall be by environmental surcharge to existing rates imposed as a positive or negative adjustment to customer bills in the second month following the month in which costs are incurred." Explain why Duke Kentucky is proposing to incorporate forecasted environmental surcharge costs into base rates.

b. Refer to KRS 278.183, Section 3, which states, in relevant part, "Every two (2) years the commission shall review and evaluate past operation of the surcharge, and after hearing, as ordered, shall … to the extent appropriate, incorporate surcharge amounts found just and reasonable into the existing base rates of each utility." Explain why Duke Kentucky is proposing to incorporate its historic environmental surcharge costs into base rates.

RESPONSE:

a. The Company is not proposing to incorporate forecasted environmental surcharge costs into base rates. The Company is proposing to roll historical plant in service included in Rider ESM into base rates.

b. The Company is proposing to incorporate historical plant in service into base rates in this proceeding. The Company believes it is a clean approach to ratemaking to include all historical plant in service in rate base and reset riders at the time new base rates are put into effect so as to reduce the surcharge going forward. However, if the Commission prefers the Company keep the plant in service in Rider ESM, the Company would not oppose that decision.

PERSON RESPONSIBLE: Sarah E. Lawler

EXHIBIT ____ (LK-9)

AG-DR-02-048

REQUEST:

Refer to the Environmental Surcharge Report filed with the Commission on December 16, 2022, for the expense month of November 2022, and specifically to ES Form 2.20.

a. Confirm that the Company is amortizing the costs of the East Bend coal ash Asset Retirement Obligations ("ARO") over ten years on an equal monthly basis, equivalent to a levelized or annuitized form of amortization and recovery. If this is not accurate, then provide a corrected statement and the source of the information relied on for the corrected statement.

b. Indicate where in the Company's pending Application, testimony, and/or responses to discovery in Case 2015-00187, Case 2017-00321, or other case/proceeding, it explained to the Commission its proposed calculations for the monthly recovery of the coal ash ARO over ten years, including a return on the unamortized amount at its weighted average cost of capital, on a levelized basis.

c. Provide the Excel spreadsheet in live format and with all formulas intact used to calculate the monthly amortization of the East Bend coal ash ARO.

d. Confirm that the Company's proposal to roll in the capital costs from the ESM to base rates in this rate case proceeding does not include the roll in of the coal ash ARO to base rates. If confirmed, explain why it does not.

e. The ESM Form 2.20 provides a runout of the monthly recovery through May 2028 when the unamortized remaining amount is reduced to $0. Indicate if there is any significance to the May 2028 date other than the fact that it is the last month of the ten-year amortization period.

f. Confirm that in Duke Kentucky's Application at 9, paragraph 16, in Case 2015-00187, the Company stated the following:

> If the Commission approves Duke Energy Kentucky's requested regulatory asset treatment, Duke Energy Kentucky expects to make the following journal entries based on estimates available as of April 30, 2015. Amounts may change as new information regarding ash pond closure costs estimates becomes available:
>
> a. Dr. 182.3 ARO Regulatory Asset $116 million
>
> Cr. 403.1 Depreciation Expense for ARC $116 million
>
> Defer depreciation expense of Asset Retirement Cost (ARC) in Account 101 over the remaining life of the asset (annual amount of approximately $4.4 million).

g. Refer to the prior question and confirm that the annual amortization of approximately $4.4 million was calculated based on an East Bend service life through 2041 ($116 million divided by $4.4 million equals approximately 26 years; 2015 plus 26 equals 2041). If not, explain why not.

RESPONSE:

a. Per Commission order in Case No. 2017-00321, the Company is amortizing the costs of the East Bend coal ash Asset Retirement Obligations (ARO) through April 2018 over ten years on an equal monthly basis, equivalent to a levelized or annuitized form of amortization and recovery. The remaining coal ash ARO costs per that same order are being recovered monthly as spent on a two-month lag.

b. Objection. This request is unreasonable and overly burdensome as it seeks publicly available information contained in orders by the Kentucky Public Service Commission that is accessible to the Attorney General. In this regard, it is harassing in nature as it is requiring the Company to engage in busywork. Without waiving said objection, and to the extent discoverable, in Case No. 2017-00321, Cynthia S. Lee discusses the Company's proposed calculations for the monthly recovery of the coal ash ARO over ten years, including a return on the unamortized amount at its weighted average cost of capital, on a levelized basis in her direct testimony and rebuttal testimony. The December 15, 2015 Final Order in Case No. 2015-00187, page 8, item 3, approved carrying costs on the unamortized coal ash regulatory asset. The April 13, 2018 Commission Order in Case No. 2017-0032, page 79, item 7, approved Duke Energy's request to amortize the East Bend Ash Pond ARO over a ten-year period is approved.

c. Please see AG-DR-02-040 Attachment 1 and Attachment 2, ES FORM 2.20, for the Excel spreadsheet in live format and with all formulas intact used to calculate the monthly amortization of the East Bend coal ash ARO.

d. Confirmed. The Company's proposal to roll in the capital costs from the ESM to base rates in this rate case proceeding does not include the roll in of the coal ash ARO to base rates. Coal ash ARO was not rolled into base rates to ensure that customers pay no more or no less than the actual amortization.

e. There is not any significance to the May 2028 date other than it is the last month of the ten-year amortization period.

f. Confirmed.

g. Confirmed; however, the example included in the application in Case No. 15-00187 is currently irrelevant. See the response to b. for the Commission approved treatment of the amount of East Bend coal ash ARO.

PERSON RESPONSIBLE: As to Objection, Legal
As to Response, Lisa D. Steinkuhl

EXHIBIT ____ (LK-10)

Retired Asset Recovery Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to all rate schedules listed in Section 1 of the General Index except Rate PSA and Special Charges and all Pilot Programs listed in Section 3 of the General Index. Rate schedules subject to this adjustment clause are divided into Group 1 or Group 2 as follows:

Group 1: Rates RS; RTOD-Energy; RTOD-Demand; VFD; LS; RLS; LE; and TE.

Group 2: Rates GS; GTOD-Energy; GTOD-Demand; PS; TODS; TODP; RTS; FLS; EVSE; EVC-L2; EVC-FAST; and OSL.

RATE

The monthly billing amount under each of the schedules to which this rider is applicable, shall be increased or decreased by a percentage factor calculated in accordance with the following formula.

Group RAR Billing Factor = Group E(m) / Group R(m)

As set forth below, Group E(m) is the sum of Jurisdictional E(m) of each approved retirement-related regulatory asset revenue requirement for the current expense month allocated to each of Group 1 and Group 2. Group R(m) for Group 1 is the twelve (12) month average revenue for the current expense month and for Group 2 it is the twelve (12) month average non-fuel revenue for the current expense month.

DEFINITIONS

1. Retirement Assets are the regulatory assets and associated ADIT created after the date of the Commission's Final Order in Case No. 2020-00350 for the Retirement Costs of generating assets retired and other site-related assets that will not continue in use.

DATE OF ISSUE: July 20, 2021

DATE EFFECTIVE: With Service Rendered
On and After July 1, 2021

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2020-00350 dated June 30, 2021

DEFINITIONS (continued)

2. Retirement Costs include the net book value, materials and supplies that cannot be used economically at other plants owned by Company, and removal costs and salvage credits, net of related accumulated deferred income tax ("ADIT"). Related ADIT shall include the tax benefits from tax losses.

3. For each Retirement Asset, E(m) is the monthly levelized expense required to amortize the Retirement Asset over a 10-year amortization period beginning with the month in which the Retirement Asset is created. E(m) includes a weighted average cost of capital component using the most recently approved base rate return on equity and adjusted for the Company's composite federal and state income tax rate.

4. Total E(m) (sum of each approved Retirement Asset revenue requirement) is multiplied by the Jurisdictional Allocation Factor. Jurisdictional E(m) is adjusted for any (Over)/Under collection or prior period adjustment and by the subtraction of the Revenue Collected through Base Rates for the Current Expense month to arrive at Adjusted Net Jurisdictional E(m). Adjusted Net Jurisdictional E(m) is allocated to Group 1 and Group 2 on the basis of Revenue as a Percentage of Total Revenue for the twelve (12) months ending with the Current Month to arrive at Group 1 E(m) and Group 2 E(m).

5. The Group 1 R(m) is the average of total Group 1 monthly base revenue for the twelve (12) months ending with the current expense month. Base revenue includes customer, energy, and lighting charges for each rate schedule included in Group 1 to which this rider is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause, Environmental Cost Recovery Surcharge, Off-System Sales Adjustment Clause, and the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 1.

6. The Group 2 R(m) is the average of total Group 2 monthly base non-fuel revenue for the twelve (12) months ending with the current expense month. Base non-fuel revenue includes customer, non-fuel energy, and demand charges for each rate schedule included in Group 2 to which this rider is applicable and automatic adjustment clause revenues for the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 2. Non-fuel energy is equal to the tariff energy rate for each rate schedule included in Group 2 less the base fuel factor as defined on Sheet No. 85.1, Paragraph 6.

7. Current expense month (m) shall be the second month preceding the month in which the Retired Asset Recovery Rider is billed.

EXHIBIT ____ (LK-11)

Kentucky Utilities Company

Standard Rate Rider **RAR** N

Retired Asset Recovery Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to all rate schedules listed in Section 1 of the General Index except Rate PSA and Special Charges and all Pilot Programs listed in Section 3 of the General Index. Rate schedules subject to this adjustment clause are divided into Group 1 or Group 2 as follows:

Group 1: Rates RS; RTOD-Energy; RTOD-Demand; VFD; AES; LS; RLS; LE; and TE.

Group 2: Rates GS; GTOD-Energy; GTOD-Demand; PS; TODS; TODP; RTS; FLS; EVSE; EVC-L2; EVC-FAST; and OSL.

RATE

The monthly billing amount under each of the schedules to which this rider is applicable, shall be increased or decreased by a percentage factor calculated in accordance with the following formula.

Group RAR Billing Factor = Group E(m) / Group R(m)

As set forth below, Group E(m) is the sum of Jurisdictional E(m) of each approved retirement-related regulatory asset revenue requirement for the current expense month allocated to each of Group 1 and Group 2. Group R(m) for Group 1 is the twelve (12) month average revenue for the current expense month and for Group 2 it is the twelve (12) month average non-fuel revenue for the current expense month.

DEFINITIONS

1. Retirement Assets are the regulatory assets and associated ADIT created after the date of the Commission's Final Order in Case No. 2020-00349 for the Retirement Costs of generating assets retired and other site-related assets that will not continue in use.

DATE OF ISSUE: July 20, 2021

DATE EFFECTIVE: With Service Rendered
On and After July 1, 2021

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2020-00349 dated June 30, 2021

DEFINITIONS (continued)

2. Retirement Costs include the net book value, materials and supplies that cannot be used economically at other plants owned by Company, and removal costs and salvage credits, net of related accumulated deferred income tax ("ADIT"). Related ADIT shall include the tax benefits from tax losses.

3. For each Retirement Asset, E(m) is the monthly levelized expense required to amortize the Retirement Asset over a 10-year amortization period beginning with the month in which the Retirement Asset is created. E(m) includes a weighted average cost of capital component using the most recently approved base rate return on equity and adjusted for the Company's composite federal and state income tax rate.

4. Total E(m) (sum of each approved Retirement Asset revenue requirement) is multiplied by the Jurisdictional Allocation Factor. Jurisdictional E(m) is adjusted for any (Over)/Under collection or prior period adjustment and by the subtraction of the Revenue Collected through Base Rates for the Current Expense month to arrive at Adjusted Net Jurisdictional E(m). Adjusted Net Jurisdictional E(m) is allocated to Group 1 and Group 2 on the basis of Revenue as a Percentage of Total Revenue for the twelve (12) months ending with the Current Month to arrive at Group 1 E(m) and Group 2 E(m).

5. The Group 1 R(m) is the average of total Group 1 monthly base revenue for the twelve (12) months ending with the current expense month. Base revenue includes customer, energy, and lighting charges for each rate schedule included in Group 1 to which this rider is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause, Environmental Cost Recovery Surcharge, Off-System Sales Adjustment Clause, and the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 1.

6. The Group 2 R(m) is the average of total Group 2 monthly base non-fuel revenue for the twelve (12) months ending with the current expense month. Base non-fuel revenue includes customer, non-fuel energy, and demand charges for each rate schedule included in Group 2 to which this rider is applicable and automatic adjustment clause revenues for the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 2. Non-fuel energy is equal to the tariff energy rate for each rate schedule included in Group 2 less the base fuel factor as defined on Sheet No. 85.1, Paragraph 6.

7. Current expense month (m) shall be the second month preceding the month in which the Retired Asset Recovery Rider is billed.

EXHIBIT ____ (LK-12)

Duke Energy Kentucky
Case No. 2022-00372
STAFF Second Set Data Requests
Date Received: January 11, 2023

STAFF-DR-02-001

REQUEST:

Refer to the Application, page 15, paragraphs 25–26.

a. Explain why these costs qualify for regulatory asset treatment.

b. Explain whether Duke Kentucky proposes that the revenues associated with these tariffs will also be deferred. If not, explain why not.

RESPONSE:

a. Please see the Direct Testimony of Danielle L. Weatherston beginning on page 6, Line 19 through page 9, Line 19.

b. As outlined in the Direct Testimony of Sarah E. Lawler and Danielle L. Weatherston, the regulatory asset being requested for the placeholder Rider GTM is for any remaining net book value not yet recovered from customers for assets that are retired. At the time of retirement, any remaining net book value associated with these retired assets would be moved to a regulatory asset. At the time that Rider GTM is put into rates, to the extent there are any revenues included in base rates associated with these assets, the Rider GTM would reflect a credit for those revenues to ensure no double recovery. But it would not be necessary to net revenues in the regulatory asset. The regulatory asset being requested for the new Rate RS-TOU-CPP is for lost revenues associated with that program. There are no revenues to be deferred. The regulatory asset being requested for Rate MRC is for costs to be deferred now and then amortized in a future base rate case. Any additional revenues generated from the result of electric vehicle adoption would also be included in that future base rate case decreasing the revenue deficiency in that proceeding and therefore no offset is needed in the regulatory asset.

PERSON RESPONSIBLE: Sarah E. Lawler

EXHIBIT ____ (LK-13)

AG-DR-01-092

REQUEST:

Refer to the Lawler Testimony at 17 – 20, regarding the Company's proposal to create a "placeholder" Generation Asset True-up Mechanism ("Rider GTM). Refer also to the entire Park Testimony regarding the future retirement of the East Bend 2 and Woodsdale generating units. Finally, refer to the draft Rider GTM tariff included in the Company's application.

a. Confirm that the Company's retirement study and proposed depreciation rates reflect estimated retirement dates for East Bend 2 and the Woodsdale generating units of 2035 and 2040, respectively.

b. Explain why the Company is seeking approval of Rider GTM now when the estimated retirement date for East Bend 2 is not until 2035, more than 12 years into the future.

c. Neither the Company's testimony regarding Rider GTM nor the draft tariff indicate how the Company will compensate ratepayers for the return on rate base, depreciation expense, property tax expense, non-fuel O&M expense, and other operating expenses included in the base revenues when the generating units actually are retired and Rider GTM is implemented. Provide a specific proposal for how the Company plans to credit ratepayers when the generating units are actually retired for the amounts recovered in base revenues to ensure that the Company does not recover the return on rate base and depreciation expense twice and does not recover other operating expenses that no longer will be incurred.

RESPONSE:

a. Objection. Calls for speculation and guesswork. The Company does not know what the AG refers to as a "retirement study" and therefore cannot answer the question. Without waiving said objection, and to the extent discoverable, the Company confirms that the depreciation study to determine the proposed depreciation rates used in this proceeding reflects estimated retirement dates for East Bend 2 and the Woodsdale generating units of 2035 and 2040, respectively.

b. See response to STAFF-DR-02-042.

c. See response to STAFF-DR-02-042.

PERSON RESPONSIBLE: As to objection, Legal
As to response, Sarah E. Lawler

EXHIBIT ____ (LK-14)

Duke Energy Kentucky
Case No. 2022-00372
STAFF Second Set Data Requests
Date Received: January 11, 2023

STAFF-DR-02-042

REQUEST:

Refer to Schedule L-2.2, page 39, Rider GTM, Generation Asset True Up Mechanism. Explain why Rider GTM is being proposed at this time.

RESPONSE:

As explained in the Direct Testimony of Ms. Lawler, the Company is requesting approval of a placeholder rider as part of this proceeding to reconcile any remaining undepreciated plant balances following future retirements of its generating assets. Creating this rider now provides a mechanism to ensure that the customers pay no more or no less than the actual costs incurred by the Company for these assets. The Company believes that requesting this rider as part of this base rate case is administratively efficient and provides certainty to the Company as to the regulatory treatment of these assets upon retirement and reduces the balance sheet risk and impact of any significant undepreciated plant remaining at the time of unit retirement. As outlined in Ms. Lawler's testimony, the Company would not plan to populate the rider until the assets are retired. Also discussed in Ms. Lawler's direct testimony, the Company would file a separate application to implement the rider and that application would be subject to Commission determination of reasonableness. The Company would make necessary calculations in that proceeding to ensure that it does not over or double recover the remaining NBV of the assets in base rates.

PERSON RESPONSIBLE: Sarah E. Lawler

EXHIBIT ____ (LK-15)

DECOMMISSIONING RIDER
(D.R.)

APPLICABLE.

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

RATE.

1. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2012-00578 and the Stipulation and Settlement Agreement dated July 2, 2013 as filed and approved by the Commission, Kentucky Power Company is to recover from retail ratepayers the coal-related retirement costs of Big Sandy Unit 1, the retirement costs of Big Sandy Unit 2 and other site-related retirement costs that will not continue in use on a levelized basis, including a weighted average cost of capital (WACC) as set in the Company's most recent Rate Case carrying cost over a 25 year period beginning with the date rates became effective in Case No. 2014-00396. The term "Retirement Costs" are defined as and shall include the net book value, materials and supplies that cannot be used economically at other plants owned by Kentucky Power, and removal costs and salvage credits, net of related ADIT. Related ADIT shall include the tax benefits from tax abandonment losses.

   The applicable rates for service rendered on and after September 28, 2022 to be applied to the revenues described in paragraph 5 of this tariff are: T

Residential Adjustment Factor	=	$12,203,475 / $260,106,760	=	4.6917%	R IR
All Other Classes Adjustment Factor	=	$14,511,306 / $183,145,514	=	7.9234%	IR I

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

   Residential Allocation RA(y) = ARR(y) x KY Residential Retail Revenue RR(b) / KY Retail Revenue R(b)

   All Other Allocation OA(y) = ARR(y) x KY All Other Classes Retail Revenue OR(b) / KY Retail Revenue R(b)

   Where:
   (y) = the expense year;

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

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

DATE OF ISSUE: August 12, 2022
DATE EFFECTIVE: Service Rendered On And After September 28, 2022
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority Of an Order of the Public Service Commission
In Case No. XXXX-XXXXX Dated XXXX XX, XXXX

KENTUCKY
PUBLIC SERVICE COMMISSION
Linda C. Bridwell
Executive Director
Linda C. Bridwell
EFFECTIVE
9/28/2022
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

DECOMMISSIONING RIDER (CONT'D)

RATE. (Cont'd)

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

Residential D.R. Adjustment Factor	=	Net Annual Residential Allocation NRA(y) / Residential Retail Revenue RR(b)

Where:

Net Annual Residential Allocation NRA(b)	=	Annual Residential Allocation RA(y), net of Over/ (Under) Recovery Adjustment;
Residential Retail Revenue RR(b)	=	Annual Retail Revenue for all KY residential classes for the year (b).

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

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

Where:

Net Annual All Other Allocation NOA(y)	=	Annual All Other Allocation OA(y), net of Over/ (Under) Recovery Adjustment;
All Other Classes Non-Fuel Retail Revenue ONR(b)	=	Annual Non-Fuel Retail Revenue for all classes other than residential for the year (b).

5. The Revenues to which the residential Decommissioning Rider factor are applied is the sum of the customer's Service Charge, Energy Charge(s), Fuel Adjustment Clause, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Cut, Residential Energy Assistance, Capacity Charge, Purchase Power Adjustment. T

   The Revenues to which the all other customer Decommissioning Rider factor are applied is the sum of the customer's Service Charge, Demand Charge, Energy Charge(s) less Base Fuel, Minimum Charge, Reactive Charge, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Cut, Kentucky Economic Development Surcharge, Capacity Charge, and Purchase Power Adjustment. T

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

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

DATE OF ISSUE: April 9, 2021
DATE EFFECTIVE: Service Rendered On And After January 14, 2021
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of Orders of the Public Service Commission
In Case No. 2020-00174 dated January 13, 2021; January 15, 2021; February 22, 2021, and March 17, 2021

KENTUCKY
PUBLIC SERVICE COMMISSION
Linda C. Bridwell
Executive Director
Linda C. Bridwell
EFFECTIVE
1/14/2021
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

EXHIBIT ____ (LK-16)

Duke Energy Kentucky
Case No. 2022-00372
Attorney General's First Set Data Requests
Date Received: January 11, 2023

AG-DR-01-023

REQUEST:

Refer to the Spiller Testimony at 29. Ms. Spiller states that current modeling shows that by 2035, the East Bend plant will not provide economic value to customers, at which point retirement will be warranted.

a. Explain whether the Company has analyzed whether East Bend would provide reliability and resiliency to the electric customers if kept running past 2035.

b. Provide an overview of what variables could cause the East Bend plant to continue being economic to the customers past 2035. Include in this discussion any potential for PJM Interconnection ("PJM") to request East Bend to stay open for reliability purposes.

c. Provide the net plant balance not yet depreciated on the East Bend generating unit as of January 2023.

d. Explain whether Duke Kentucky includes the undepreciated amounts that customers will have to pay for in rates if the East Bend generating unit is retired early when conducting its modeling of economic value to customers.

e. Ms. Spiller asserts that in the 2019 rate case the Company assumed the retirement date of the Woodsdale generating unit to be 2032, but now proposes to extend the useful life of this asset until 2040.

   i. Explain why Duke Kentucky decided to extend the life of the Woodsdale generating unit.

ii. Provide all studies/analyses that led Duke Kentucky to make the decision to not retire Woodsdale until 2040.

RESPONSE:

a. The company has not performed that analysis, but it is reasonable to assume that it would be true.

b. Please see AG-DR-01-022(b).

c. Net plant balance, not yet depreciated, for East Bend generating plant was $483,996,260 as of November 2022. This amount represented Net Book Value (Life only) of Production assets including land, excluding AROs as of November 2022. Data as of January 2023 is not available as of today. Also see the Company's response to STAFF-DR-02-020.

d. The economic evaluation the IRP does not get into the rate making aspect of any potential undepreciated amounts on East Bend 2 or any unit for that matter.

e.

i. Woodsdale station as a peaking facility provides reliable and dispatchable capacity to customers and would continue to be a useful asset as the generating fleet transitions to one that is more diverse with less environmental impact.

ii. Analysis was performed that include portfolios where Woodsdale station operated through 2040. These included the preferred portfolio of the 2021 Duke Energy Kentucky IRP and was done to lessen the impact of the rate impact of replacing Woodsdale to customers.

PERSON RESPONSIBLE: Scott Park – a., b., d., e.
Huyen C. Dang – c.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

LANE KOLLEN, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Lane Kollen

Sworn to and subscribed before me on this
10th day of March 2023.

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2023
CHEROKEE COUNTY, GEORGIA