BEFORE THE

PUBLIC SERVICE COMMISSION OF THE

COMMONWEALTH OF KENTUCKY

IN RE:	**APPLICATION OF ATMOS ENERGY**	**)**	
	CORPORATION FOR AN	**)**	**CASE NO. 2018-00281**
	ADJUSTMENT OF RATES AND	**)**	
	TARIFF MODIFICATIONS	**)**	

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

OFFICE OF THE ATTORNEY GENERAL

J. Kennedy and Associates, Inc.
570 Colonial Park Drive, Suite 305
Roswell, GA 30075

JANUARY 28, 2019

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TABLE OF CONTENTS

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	TARIFF MODIFICATIONS	**)**	

DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

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

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

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

Q. Please describe your education and professional experience.

A. I earned both a Bachelor of Business Administration in Accounting degree and a Master of Business Administration degree from the University of Toledo. I also earned a Master of Arts degree in Theology from Luther Rice University. I am a Certified Public Accountant, with a practice license, Certified Management Accountant, and Chartered Global Management Accountant. I am a member of numerous professional organizations.

I have been an active participant in the utility industry for more than thirty years, both as an employee and as a consultant. Since 1986, I have been a consultant with J. Kennedy and Associates, Inc., providing services to state government agencies and consumers of utility services in the ratemaking, financial, tax, accounting, and management areas. From 1983 to 1986, I was a consultant with Energy Management Associates, providing services to investor and consumer owned utility companies. From 1976 to 1983, I was employed by The Toledo Edison Company in a series of positions encompassing accounting, tax, financial, and planning functions. From 1974 to 1976, I was employed by a contractor to Ohio Bell Telephone Company and Buckeye Cablevision and installed underground cable.

I have appeared as an expert witness on accounting, tax, finance, ratemaking, and planning issues before regulatory commissions and courts at the federal and state levels on hundreds of occasions. I have testified in numerous proceedings before the Kentucky Public Service Commission ("Commission"), including numerous base, fuel adjustment clause, and environmental surcharge ratemaking proceedings involving Big Rivers Electric Corporation, East Kentucky Power Cooperative, Kentucky Power Company, Kentucky Utilities Company ("KU"), and Louisville Gas and Electric Company ("LG&E"). In addition, I testified in the two most recent Atmos base rate cases prior to this proceeding (Case Nos. 2015-00343 and 2017-00349) and in the most recent Columbia Gas rate case (Case No. 2016-00152). Further, I have testified before the Georgia Public Service Commission in multiple Atmos base rate proceedings.[1]

Q. On whose behalf are you testifying?

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: 1) summarize my recommendation to reduce the base revenue requirement and requested increase, 2) address the Company's request to terminate the present Pipeline Replacement Program ("PRP") rider and include forecast PRP costs in the base revenue requirement, 3) address and make recommendations on specific issues that affect the base revenue requirement in this

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

proceeding, and 4) quantify the effects of maintaining the present 9.7% authorized return on equity.

Q. Please summarize your testimony.

A. I recommend a base revenue *reduction* of $7.970 million compared to the Company's corrected request for a base revenue increase of $14.510 million, as adjusted for errors acknowledged in response to Staff discovery. The following table lists each of my adjustments and the effect on the Company's claimed revenue deficiency.[2] I developed my adjustments in consultation with the AG, but I understand that the AG's final adjustments may differ based upon discovery, testimony and further evidence produced at the hearing.

[2] The quantifications are detailed in my electronic workpapers, which were filed at the same time as my testimony was filed. The electronic workpapers consist of an Excel workbook in live format and with all formulas intact.

Atmos Energy Corporation - Kentucky Division
Summary of Attorney General Recommendations
KPSC Case No. 2018-00281
Test Year Ended March 31, 2020
$ Millions

	Before Gross-Up Amount	B/D and PSC Gross-up	Adjustment Amount
Atmos Requested Increase			
Atmos Request Based on Original Filing			$ 14.456
Atmos Corrections to State Tax Rate, Depreciation, and Other Provided in Staff 2-64			0.054
Atmos Adjusted Request Based on Response to Staff 2-64			$ 14.510
Effects on AG Operating Income Recommendations on Revenue Requirement			
Adjust Depreciation Expense to Reflect ALG vs ELG Procedure	(7.353)	1.00705	(7.405)
Remove Depreciation Expense Related to PRP After 9/30/18	(0.485)	1.00705	(0.488)
Remove Ad Valorem Taxes Related to PRP After 9/30/18	(0.193)	1.00705	(0.194)
Reduce Depreciation Expense Related to Reduction of Non-PRP Projected Plant Expenditures	(0.432)	1.00705	(0.435)
Reduce Ad Valorem Expense Related to Reduction of Non-PRP Projected Plant Expenditures	(0.172)	1.00705	(0.173)
Effects of AG Rate Base Recommendations on Revenue Requirement			
Adjust Accumulated Depreciation and ADIT to Reflect ALG vs ELG Procedure			0.272
Remove PRP Plant Additions After 9/30/18			(2.916)
Reduce Projected Non-PRP Plant Based on Historic 3-Year Average			(2.599)
Remove CWIP in Rate Base			(3.921)
Correct Cash Working Capital			(0.821)
Effects of AG Rate of Return Recommendations on Revenue Requirement			
Include Effects of October 4, 2018 Debt Issue on Capital Structure and Debt Rate			(1.256)
Reduce Assumed Debt Rate for March 2019 Refinance			(0.132)
Reflect Return on Equity of 9.70%			(1.685)
Effects of Change In Composite Allocation Factor on All Aspects of Revenue Requirement			(0.725)
Total AG Recommendations			$ (22.480)
Base Rate Decrease after AG Recommendations			$ (7.970)

In the following sections of my testimony, I address each of the issues reflected in the preceding table in greater detail and quantify the effects on the revenue requirement of maintaining the present 9.7% authorized return on equity. I note that the return on equity also will have an effect on the Company's PRP rider in future filings, although I have not quantified those effects in the preceding table.

I recommend that the Commission reject the Company's request to terminate the PRP rider and include forecast PRP costs in the base revenue requirement. If adopted, this request effectively would circumvent the customer safeguards addressing the scope, timing, and magnitude of PRP cost recovery that the Commission imposed in Case No. 2017-00349. I have reflected the effects of this recommendation on the preceding table.

In addition, I recommend that the Commission reject the Company's request for current recovery of a return on construction work in progress ("CWIP") in rate base and instead direct the Company to capitalize its construction financing costs as Allowance for Funds Used During Construction ("AFUDC") for ratemaking purposes.

The AFUDC approach is good regulatory policy. The AFUDC approach properly adds the construction financing costs to CWIP and then allows a utility to recover these costs over the service lives of the assets. In contrast, the CWIP in rate base approach allows a utility to prematurely recover construction financing costs from customers during the construction period and before the assets provide service. In addition, the AFUDC approach is consistent with generally accepted accounting principles ("GAAP"), which require that construction financing costs be capitalized and then depreciated over the service lives of the assets. Further, the AFUDC approach ensures that a utility recovers its actual construction financing costs, no more and no less. Finally, adoption of the AFUDC approach will ensure that the

Atmos construction financing costs are treated consistently with Kentucky Power Company, Duke Energy Kentucky, Inc. (electric and gas), Columbia Gas of Kentucky, Inc., Kentucky Utilities Company (Virginia retail jurisdiction) for ratemaking purposes, and hopefully, with Kentucky Utilities and Louisville Gas & Electric Company, if the Commission adopts the AFUDC approach in their pending base rate proceedings.[3]

II. OPERATING INCOME ISSUES

A. Reduce Depreciation Expense to Reflect ALG Procedure Instead of ELG Procedure for Calculation of Depreciation Rates

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

A. The Company proposes to change its depreciation rates effective at the beginning of the test year to reflect the results of a depreciation study performed by Mr. Dane Watson using a study date of September 30, 2017.

The Company's proposed depreciation rates are based on the Equal Life Group ("ELG") procedure instead of the Average Life Group ("ALG") procedure, even though ALG is the dominant procedure used by other electric and gas utilities, including all other investor-owned electric and gas utilities in the Commonwealth.

[3] Case Nos. 2018-00294 and 2018-00295.

Q. How do the ELG depreciation rates developed by Mr. Watson compare to the ALG rates provided in response to AG discovery?

A. The ELG depreciation rates are significantly greater than the ALG rates using similar depreciation parameters (interim retirement curves, cost of removal, salvage income, average service lives), as is typically the case. The following tables provide a comparison of the depreciation rates under the two procedures.

Atmos Energy Corporation - Kentucky Properties
Comparison of Depreciation Annual Accrual Rates ELG vs ALG
As Calculated by Atmos

Account	Description	ELG Accrual Rate	ALG Accrual Rate
	STORAGE PLANT		
35020	Rights-Of-Way	0.47%	0.36%
35100	Structures And Improvements	1.66%	1.60%
35102	Compressor Station Eq	1.25%	1.18%
35103	Measuring And Reg. Station	0.90%	0.79%
35104	Other Structures	1.29%	1.20%
35200	Wells	1.93%	1.90%
35201	Well Construction	1.52%	1.42%
35202	Well Equipment	1.21%	1.09%
35203	Cushion Gas	1.38%	1.36%
35210	Storage Leaseholds An	0.31%	0.15%
35211	Storage Rights	0.88%	0.78%
35301	Storage Field Lines	0.91%	1.12%
35302	Storage Tributary Lines	0.91%	1.12%
35400	Compressor Station Eq	1.70%	1.64%
35500	Measuring And Regulating	1.67%	1.71%
35600	Purification Equipment	1.98%	1.95%
	Total Storage	1.72%	1.68%

Atmos Energy Corporation - Kentucky Properties
Comparison of Depreciation Annual Accrual Rates ELG vs ALG
As Calculated by Atmos

Account	Description	ELG Accrual Rate	ALG Accrual Rate
	TRANSMISSION PLANT		
36520	Rights-Of-Way	1.05%	0.74%
36602	Meas. & Reg. Sta. Structures	1.24%	0.71%
36603	Other Structures	1.24%	0.71%
36700	Mains - Cathodic Protection	3.84%	3.28%
36701	Mains - Steel	1.41%	1.16%
36703	Mains - Anodes	5.00%	5.00%
36900	Measuring And Reg. Station	1.54%	1.25%
36901	Measuring And Reg. Station	1.54%	1.25%
	Total Transmission	1.43%	1.17%

Atmos Energy Corporation - Kentucky Properties
Comparison of Depreciation Annual Accrual Rates ELG vs ALG
As Calculated by Atmos

Account	Description	ELG Accrual Rate	ALG Accrual Rate
	DISTRIBUTION PLANT		
37402	Land Rights	1.36%	1.29%
37500	Structures & Improvements	1.79%	1.25%
37501	Struct. & Improv. - T	1.79%	1.25%
37502	Land Rights	1.79%	1.25%
37503	Improvements	1.79%	1.25%
37600	Mains - Cathodic Protection	4.24%	3.42%
37601	Mains - Steel	2.52%	1.43%
37602	Mains - Plastic	2.52%	1.43%
37603	Mains - Anodes	5.00%	5.00%
37604	Mains - Leak Clamps	5.00%	5.00%
37800	Measuring & Regulating Eq	3.05%	2.10%
37900	Measuring & Regulating Eq	2.83%	1.99%
37905	Measuring & Regulating Eq - City	2.83%	1.99%
38000	Services	3.19%	2.25%
38100	Meters	7.05%	4.54%
38200	Meter Installations	3.91%	2.69%
38300	House Regulators	4.01%	2.76%
38400	House Regulator Installations	3.47%	2.44%
38500	Industrial Measuring	2.14%	1.38%
	Total Distribution	3.24%	2.14%

Atmos Energy Corporation - Kentucky Properties
Comparison of Depreciation Annual Accrual Rates ELG vs ALG
As Calculated by Atmos

Account	Description	ELG Accrual Rate	ALG Accrual Rate
GENERAL PLANT - DEPRECIATED			
39000	Structures & Improvements	3.22%	2.49%
39002	Structures - Brick	3.22%	2.49%
39003	Improvements	3.22%	2.49%
39004	Air Conditioning Equipment	5.64%	5.01%
39009	Improvements - Leased	16.04%	12.37%
39200	Transportation Equipment	5.15%	4.70%
39202	Transportation - Trailers	5.15%	4.70%
39603	Power Operated -Ditchers	11.35%	8.75%
39604	Power Operated - Backhoes	11.35%	8.75%
39605	Power Operated - Welders	11.35%	8.75%
	Total General Depreciated	5.03%	3.90%

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

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

Q. Why is that?

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

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

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

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

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

Q. Did the Commission recently find that the ALG procedure is superior to the ELG procedure in Case No. 2017-00321 where Duke (electric) sought approval of new depreciation rates calculated using the ELG procedure?

A. Yes. In its Order, the Commission recited the AG's claims regarding the ALG and ELG as follows:

> The Attorney General recommends the Commission adopt the ALG procedure in developing Duke Kentucky's depreciation rates. The Attorney General contends that the ALG methodology is the predominant method that is used in the electric industry for developing depreciation rates. The Attorney General contends that, under the ELG methodology, the capital recovery periods are accelerated and shortened and, thus, the depreciation rates are greater than if the ALG procedure was used. The Attorney General argues that the ALG procedure is as accurate as the ELG procedure and the ALG procedure smooths the data so that the depreciation rates for the group of assets tend to remain constant.[4] [footnotes omitted].

The Commission found the following:

> As discussed in the testimony of the Attorney General, the ELG procedure front-loads depreciation expense in earlier years and decreases it in the later years of an asset's depreciable life, creating a mismatch of revenues and expenses. The Attorney General states that the ALG procedure is the dominant procedure for other electric utilities, including all other electric utilities in Kentucky. Therefore, the Commission finds that the Attorney

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[4] Case No. 2017-00321, *In Re: Application of Duke Energy Kentucky, Inc. for an Adjustment of its Electric Rates*, etc., Order dated April 13, 2018 at 26.

> General's position on this issue is reasonable and that Duke Kentucky should use the ALG procedure for computing depreciation rates.[5] [footnotes omitted].
>
> *****************************
>
> As was discussed in the rate base section of this Order, this Commission has found that the ELG procedure does not accurately match revenues and expenses, is front-loaded, and Duke Kentucky is the only Kentucky based utility that utilizes the ELG procedure for computing depreciation rates. Regulatory accounting requires the proper matching of revenues and expense in order to produce fair, just and reasonable rates. The Commission finds Duke Kentucky's proposed ELG procedure does not meet that criteria.[6] [footnotes omitted].

Q. What is your recommendation?

A. I recommend that the Commission adopt new depreciation rates calculated using the ALG procedure. There is no compelling reason to adopt the ELG procedure. There is no compelling reason to unnecessarily front load and increase depreciation rates and expense. The ALG procedure is fully compensatory and provides the Company full recovery of its gross plant cost, which includes the time value of the recovery because gross plant cost less accumulated depreciation is included in rate base and earns a return until the cost is depreciated.

The ALG procedure provides a normalized depreciation expense for ratemaking purposes, all else equal. The ALG procedure is as accurate as the ELG procedure, but smooths the data so that the depreciation rates for the group tend to

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[5] *Id.*, at 10.
[6] *Id.*, at 26-27.

remain constant, all else equal, over the service life of the group. In contrast, the ELG procedure results in greater depreciation rates initially, but then lower depreciation rates as each equal life sub-group is assumed fully retired.

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

A. The effect is a reduction in the revenue requirement of $7.133 million, comprised of the reduction in depreciation expense of $7.405 million (grossed-up from $7.353 million), offset in part by the return on the increase in capitalization of $0.272 million due to the reduction in accumulated depreciation net of the related increase in ADIT.[7]

III. RATE BASE ISSUES

A. PRP Rider Should Not Be Terminated and Forecast PRP Costs Should Be Removed From Rate Base and Operating Expenses in Base Revenue Requirement

Q. Describe the Company's request to terminate the PRP Rider.

A. The Company seeks to terminate the PRP Rider and include the forecast PRP costs in the base revenue requirement.

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

Q. Describe the Commission's investigation of the PRP and PRP Rider in Case No. 2017-00349.

A. The Commission conducted an investigation of the PRP and the PRP Rider in that proceeding due to its concerns about the scope, cost and timing of the PRP and the incentives and magnitude of the costs recovered through the PRP Rider.

In its Order, the Commission affirmed the PRP and recovery of PRP costs through a PRP Rider, but directed the Company to limit the annual PRP investment and extend the PRP and PRP Rider by two years. In addition, the Commission significantly modified the recovery of PRP costs through the PRP Rider by: (1) requiring the use of actual costs based on historic test years ending September 30 of the prior year; and (2) capping the annual PRP capital expenditures that could be incurred and recovered through the PRP Rider at $28 million. More specifically, the Commission found the following:

> KRS 278.509 authorizes the recovery of PRP investment costs only when the Commission has deemed the costs to be fair, just, and reasonable. In order to remove any question as to the reasonableness of the ratepayer-funded PRP, we therefore, find that Atmos's recovery of PRP investment should be based on actual spending subject to the $28 million cap in a historic 12-month period, and that budget estimates for funding a future PRP period will no longer be accepted as the basis for calculating the PRP Rider rate.
>
> Atmos should file a revision to Sheet No. 38 of its tariff to state that its annual PRP filing will reflect the impact on the company's revenue requirements of net plant additions during the most recent 12 months ended September 30, with adjustment to the Rider becoming effective March 1. Annual PRP applications should be filed no later than January 1. Atmos may

> include with its tariff revisions a provision for a balancing adjustment to reconcile collections with actual investment for the preceding program year. Applications should include sufficient detail with regard to individual projects completed to support the annual PRP revenue requirements. Atmos should also include in its annual PRP filing details concerning planned projects for the upcoming year similar to what it currently files for its future PRP investment approval.[8]

The Commission also included an ordering paragraph in its Order that reiterated the changes to the PRP Rider as follows:

> 6. Atmos's future recovery of PRP investment is limited to $28 million annually and shall be recovered based on a historic 12-month period as described herein.[9]

Q. Does the Company's request to terminate the PRP Rider comply with the provisions of the Order in Case No. 2017-00349?

A. No. The Company's multiple claims to this effect are in error and should be rejected.[10] The Company did not comply with the requirement to use a historic 12-month test year ending September 30 of the prior year based on actual costs, limited to $28 million annually in each historic test year.

Instead of complying with the Commission's Order, the Company has taken intentional actions to circumvent any actual effect of the Order on its revenues and to circumvent the customer safeguards imposed by the Commission in response to its

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[8] Case No. 2017-00349, Order dated May 3, 2018, at 42-43.
[9] *Id.*, at 47.
[10] Atmos Application at 5 (paragraph 11), Direct Testimony of Mark Martin at 9, and Direct Testimony of Gregory Smith at 3-7.

concerns with the Company's management of the program and the costs that were incurred and recovered through the PRP Rider.

The Company now seeks to terminate the PRP and PRP Rider altogether and simply redefine the form and timing of recovery so that the Commission's Final Order in the prior case is effectively mooted with no actual application and no relevance in this or any future rate proceeding. Instead of limiting the PRP costs to the actual costs incurred through September 30, 2018, the Company seeks to include not only those costs, but also <u>forecast</u> PRP costs from October 1, 2018 through March 31, 2020 in the rate base used for the return component, as well as the depreciation expense, included in the base revenue requirement. The following chart shows the interrelationship and timing of the PRP costs included in the Company's filed base revenue requirement compared to the timing and recovery of the PRP costs through the PRP Rider.

Total Capital Additions Through March 31, 2020 Included In Atmos Base Revenue Requirement $87.9 Million ($45.9 Million FY 2018 + $14 Million Oct 1, 2018-Mar 31, 2019+ $28 Million Apr 1, 2019-Mar 31, 2020)				
		Base Test Year Apr 1, 2019 - Mar 31, 2020 $28 Million		
PRP Fiscal Year 2018 Incl In Base Rev Req	PRP Test Year Fiscal Year 2019 Under PRP Rider		PRP Test Year Fiscal Year 2020 Under PRP Rider	
$45.9 Million	$14 Million	$14 Million	$14 Million	$14 Million

Instead of limiting the PRP costs to $28 million annually in the historic test year ending September 30, 2018 (the amount that would be recovered through the

PRP Rider from March 1, 2019 through February 28, 2020 pursuant to the Commission's Order in Case No. 2017-00349),[11] the Company included an additional <u>$42 million</u> in PRP costs from October 1, 2018 through March 31, 2020 in the base revenue requirement ($28 million in fiscal year 2019 from October 1, 2018 through September 30, 2019 plus $14 million in fiscal year 2020 from October 1, 2018 through March 31, 2020).[12] Under the terms of the Commission's Final Order in Case No. 2017-00349, the PRP costs incurred from October 1, 2018 through September 30, 2019 would not be eligible for recovery through the PRP Rider until March 1, 2020, and the costs incurred from October 1, 2019 through March 31, 2020 would not be eligible for recovery through the PRP Rider until March 1, 2021.

Q. Does the Company's proposal to terminate the PRP and the PRP Rider achieve the regulatory objectives the Commission reflected in the Final Order in Case No. 2017-00349?

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[11] This assumes that the $28 million in authorized actual PRP spending through September 30, 2018 is included in the base revenue requirement in this proceeding (effectively, a continuation of the "roll-in" reflected in Case No. 2017-00349, but updated for the revisions to the PRP Rider adopted in Case No. 2017-00349) and not in a PRP filing made on or before January 1, 2019 for an effective date of March 1, 2019 through February 28, 2020. The Company included PRP investment of $44.9 million in the test year ending September 30, 2018 in Case No. 2017-00349. The Company actually incurred $45.9 million in PRP investment in fiscal year 2018 (response to Staff 3-22), but I do not recommend that $17.9 million be removed from the rate base to reduce it to $28 million because the Commission did not reduce the $44.9 million in conjunction with the roll-in of the PRP costs in the Case No. 2017-00349.

[12] Response to Staff 3-22.

A. No. If its proposals in this proceeding are adopted, the Company will recover forecast costs in real-time even though the Commission intentionally limited recovery of PRP costs to actual costs incurred in a historic test year and on a lagged recovery basis. In this proceeding, the Company now claims that it limited the annual capital additions to $28 million (starting in fiscal year 2019) even though it no longer plans to identify or track PRP program costs in the absence of a PRP Rider.[13] The $28 million is simply an artificial threshold that the Company can and will claim to achieve even while it increases capital additions in other self-defined and subjective "non-PRP" categories. I will address this concern in more detail in the subsequent section of my testimony on excessive "non-PRP" capital additions.

Q. What is your recommendation?

A. I recommend that the Commission reject the Company's request to terminate the PRP and PRP Rider. The AG chronicled the problems with the Company's serial efforts to expand the scope of the PRP program and seeming inability or unwillingness to reasonably manage the PRP costs in Case No. 2017-00349. The Commission addressed the AG's concerns by directing changes to the scope and timing of the PRP and the costs recoverable through the PRP rider in that prior case. These changes provide essential customer safeguards and inherent incentives to reasonably manage and minimize the PRP costs. These safeguards should not be

[13] Direct Testimony of Gregory Waller at 9.

terminated. If the customer safeguards are terminated, the evidence is that the underlying problems will continue.

Q. Does your recommendation preclude recovery of authorized PRP program costs?

A. No. The Company will be able to recover the authorized PRP program costs through the PRP rider in the manner that the Commission directed in Case No. 2017-00349.

Q. What is the effect of your recommendation on the base revenue requirement?

A. The effect is a reduction of $3.598 million in the base revenue requirement, consisting of a reduction of $2.916 million for the return on rate base, a reduction of $0.488 million in depreciation expense (grossed-up from $0.485 million and quantified using the ALG depreciation rates to avoid double counting in my quantifications), and a reduction of $0.194 million in ad valorem expense (grossed-up from $0.193 million).

B. Eliminate Extreme Increases in Other "Non-PRP" Capital Expenditures

Q. Describe the capital expenditures and plant additions and compare these amounts to historic amounts.

A. The Company continues to aggressively increase its capital expenditures and plant additions regardless of the limitations on "PRP" investment the Commission imposed in Case No. 2017-00349. The following table provides a comparison of the Company's historic actual and forecast PRP and non-PRP capital expenditures.[14]

$ millions Fiscal Year	PRP Investment	Non PRP Investment	Total Direct Investment	PRP as % of Total
2013	$ 17.2	$ 18.3	$ 35.5	48%
2014	22.7	26.6	49.3	46%
2015	36.9	18.6	55.5	66%
2016	30.0	34.2	64.2	47%
2017	39.9	33.0	72.9	55%
2018	45.9	33.9	79.8	58%
2019	28.0	58.7	86.7	32%
2020	28.0	68.7	96.7	29%

As shown on the preceding table, in the years 2016-2018, the Company increased its annual actual PRP investment from $30.0 million in 2016 to $39.9 million in 2017 and then to $45.9 million in 2018. The Company's non-PRP investment was nearly the same in each of those same three years, starting at $34.2 million in 2016, declining slightly to $33.0 million in 2017, and then increasing slightly to $33.9 million in 2018. I note that the $34.2 million non-PRP investment in 2016 nearly doubled the $18.6 million non-PRP investment in 2015. I also note that these annual capital expenditures accumulate as additions to plant in service and increases in rate base.

[14] Table provided by Company in response to Staff 3-22, correcting an earlier table provided in response to AG 1-8. I have attached a copy of this response as Exhibit___(LK-16).

This recent three-year annual investment pattern changes significantly starting in 2019, with annual forecast PRP investment declining to $28 million in 2019 and 2020, ostensibly to comply with the Commission's Order in Case No. 2017-00349, and annual forecast non-PRP investment increasing from $33.9 million in 2018 to $58.7 million in 2019 and then to $68.7 million in 2020 (an increase of 102.6% over that two-year period).

The magnitude of the increase in total capital expenditures over the last several years and into the forecast years is staggering, especially for a utility that has almost no growth in customers or usage. The forecast non-PRP investment in 2020 is $50 million more than the actual non-PRP investment in 2015, an increase of approximately 270% in five years. The forecast total direct investment (PRP plus non-PRP) in 2020 is $96.7 million compared to $55.5 million in 2015, an increase of 74% even with the limitations on the PRP investment the Commission imposed in Case No. 2017-00349.[15]

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[15] The Company has not materially changed its forecast total direct investment for 2019 and 2020 in this case compared to its forecast cost for those same years in the prior case, Case No. 2017-00349 (Response to AG 1-15). More specifically, in the prior case, the Company stated that its forecast total direct investment in 2019 would be $86.3 million (compared to the preceding table, which now shows $86.7 million) and in 2020 would be $96.7 million (compared to the preceding table, which now shows $96.7 million). In the prior case, the Company stated that its forecast PRP investment was $51.1 million in 2019 and $56.9 million in 2020. (Response to Staff 2-18). In this case, the Company forecasts PRP investment of $28 million for both 2019 and 2020. It should be readily apparent that the Company simply recharacterized its total direct investment between PRP and non-PRP in this proceeding. The amounts provided in Case No. 2017-00349 were before the Commission issued its Final Order modifying the PRP and constraining cost recovery through the PRP Rider. It should be evident from this comparison, that the Company does not intend to reduce its forecast or actual total direct investment, despite the Commission's Order in the prior case, unless the Commission takes further action in this case.

Q. What do you conclude from this comparison?

A. There is no question that Atmos is intentionally and aggressively driving up its annual capital expenditures year after year. Atmos has met the Commission's attempt to limit the annual PRP investment to $28 million with staggering increases in annual non-PRP investment. The Atmos forecast total direct investment is unaffected by the Commission's attempt to reign in its PRP investment. In other words, Atmos has circumvented the Commission's limitations on PRP investment by simply recharacterizing or redefining a portion of its forecast "PRP" investment as "non-PRP" investment.

Q. Does Atmos control the actual and forecast capital expenditures (investment) or do its capital expenditures "just happen"?

A. Atmos controls its capital expenditures. Atmos acknowledged that it "manages the pace with which investment is made in infrastructure replacement as well as all other capital investment" in Case No. 2017-00349.[16] In other words, the magnitude, timing, and prioritization of capital expenditures is discretionary, except for some mandatory projects.[17]

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[16] Response to AG 1-1 in Case No. 2017-00349. I have attached a copy of this response as my Exhibit___(LK-2).

[17] The Company has stated that the objectives of its capital budgeting process are: 1) to formalize the process of identifying construction needs and prioritizing capital expenditures, 2) assess the economic feasibility of individual construction projects, 3) determine overall capital requirements for the planning

Atmos is a sophisticated utility that budgets and prioritizes its capital expenditures. Atmos recognizes that increasing its rate base through capital expenditures will increase its top line base revenues and its bottom line income even with little or no customer growth. Atmos also recognizes that the greater the forecast costs, the greater the revenue requirement and rate increases, all else equal. Of course, there is only one source of revenues to pay for these increases in costs, its customers.

Q. Should the Commission impose some discipline on Atmos to safeguard customers from these continuing and excessive increases in PRP and non-PRP investment?

A. Yes. The use of a forecast test year provides Atmos behavioral and financial incentives to maintain and accelerate the pace of capital investment. The Company's customers cannot control the pace of the capital investment. However, the Commission can constrain these continuing and excessive increases in capital investment by reducing the forecast non-PRP capital investment allowed in the test year to a reasonable amount. If constraints are imposed, then Atmos will respond to these limitations by reducing its actual spending to match the forecast non-PRP capital investment allowed in rate base or, perhaps, to something even less.

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periods, 4) reassess long term system maintenance requirements annually, and 5) review past construction projects and work practices, and apply procedural improvements as appropriate. (Response to Staff 1-11 in Case No. 2017-00349).

The evidence provided by the AG in the two prior proceedings[18] and this proceeding demonstrates that Atmos has every intention of continuing to incur and continuing to significantly increase its combined PRP and non-PRP investment each year and to seek annual base rate increases despite the Commission's efforts in the prior case to at least impose some discipline on the PRP capital expenditures and the annual PRP rider rate increases.

Q. Do you have any additional comments regarding the magnitude and impact of the Company's forecast capital investment?

A. Yes. The Company's customer base and sales are stagnant. That means the existing customer base must pay for the PRP and other non-PRP capital expenditures and operating expenses. It does not make sense for the Company's existing customers to pay to replace much of the Company's existing system and to more than double rate base and the related expenses (depreciation expense, ad valorem tax expense, and income tax expense) in the next four to six years. The Commission should encourage prioritization of capital expenditures and the exercise of control over these costs and operating expenses through the behavioral and financial incentives available in the ratemaking process.

Q. What is your recommendation?

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[18] Case Nos. 2015-00343 and 2017-00349.

A. I recommend that the Commission limit non-PRP capital expenditures included in the test year to a reasonable amount based on the Company's most recent three-year actual non-PRP expenditures in addition to my other recommendations to reject the Company's request to terminate the PRP Rider and to affirm the limitations on PRP costs and PRP Rider recovery that the Commission imposed in Case No. 2017-00349.

Q. What is the effect of your recommendation to limit non-PRP capital expenditures included in the test year to a reasonable amount based on the Company's most recent three-year actual non-PRP expenditures?

A. The effect is a reduction in the base revenue requirement of $3.207 million, consisting of a reduction of $2.599 million for the return on rate base, $0.435 million for the reduction in depreciation expense (grossed-up from $0.432 million and quantified using the ALG depreciation rates to avoid double counting in my quantifications), and $0.173 million in ad valorem expense (grossed-up from $0.172 million). This effect assumes annual non-PRP capital expenditures of $33.7 million, based on an average of the prior three fiscal years, in fiscal year 2019 and in the first six months of fiscal year 2020 (from October 1, 2018 through March 31, 2020). This effect is incremental to the effects from my recommendation to exclude all PRP expenditures after September 30, 2018 from the base revenue requirement and to recover these costs through the PRP Rider consistent with the limitations set forth in the Commission's Order in Case No. 2017-00349.

<u>C. Construction Financing Costs Should Be Capitalized as AFUDC and Recovered Over the Service Lives of the Assets, Not Included in CWIP In Rate Base and Prematurely Recovered During the Construction Period</u>

Q. Describe the Company's request for current recovery of construction financing costs.

A. The Company seeks current recovery of construction financing costs for ratemaking purposes instead of capitalizing these costs in CWIP and then recovering the costs over the service lives of the assets. This "CWIP in rate base" approach provides the Company recovery of construction financing costs before the project is completed and placed in service. The Commission historically has allowed the Company to include CWIP in rate base and to recover the grossed-up return on CWIP in the base revenue requirement.

Q. Is the Company's request for CWIP in rate base for ratemaking purposes consistent with its accounting for financial reporting purposes?

A. No. The Company records AFUDC for accounting purposes even though historically it has been allowed CWIP in rate base for ratemaking purposes in Kentucky. It removed the AFUDC included in CWIP in the test year as a proforma adjustment,[19] but it did not remove the AFUDC that it recorded in CWIP prior to the test year and that now is included in plant in service for accounting purposes and in rate base for ratemaking purposes.[20]

Q. Is that a problem?

A. Yes. The CWIP in rate base approach and AFUDC approach are generally considered to be mutually exclusive. If the utility is allowed CWIP in rate base, then it generally is not allowed and does not record AFUDC for either accounting or ratemaking purposes. Otherwise, the utility recovers a portion of its construction financing costs twice, once through the return on the CWIP in rate base, and then a second time, by capitalizing the costs as AFUDC and recovering them through depreciation expense, along with a return on the AFUDC until it is fully depreciated.

Q. Describe the AFUDC approach for capitalizing financing costs incurred during construction.

A. Under the AFUDC approach, the construction financing costs are capitalized and added to CWIP. When the project is completed and placed in service, then the plant in service cost includes the construction financing as well as all other construction costs. Under the AFUDC approach, the financing costs are calculated using the

[19] Direct Testimony of Gregory Waller at 13.

[20] Direct Testimony of Gregory Waller at 7-9. Also, see response to AG 2-18. I have attached a copy of the response to AG 2-18 as my Exhibit___(LK-3).

Company's embedded weighted cost of capital in accordance with the methodology set forth in the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA"), unless the methodology is modified for retail ratemaking purposes.

Q. Does the utility fully recover its construction financing costs under the AFUDC approach?

A. Yes. The AFUDC approach provides the utility dollar for dollar recovery of its actual construction financing costs, no more and no less.

Q. Is the AFUDC approach consistent with generally accepted accounting principles?

A. Yes. GAAP generally requires that construction financing costs be capitalized into the cost of an asset because such costs are no different in concept than the cost of labor and materials used to construct an asset and because the cost has future economic value. Statement of Financial Accounting Standards No. 34, *Capitalization of Interest Cost,* states the following:

> 39. The Board concluded that interest cost is a part of the cost of acquiring an asset if a period of time is required in which to carry out the activities necessary to get it ready for its intended use. In reaching this conclusion, the Board considered that the point in time at which an asset is ready for its intended use is critical in determining its acquisition cost. Assets are expected to provide future economic benefits, and the notion of expected

> future economic benefits implies fitness for a particular purpose. Although assets may be capable of being applied to a variety of possible uses, the use intended by the enterprise in deciding to acquire an asset has an important bearing on the nature and value of the economic benefits that it will yield.
>
> 40. Some assets are ready for their intended use when purchased. Others are constructed or otherwise developed for a particular use by a series of activities whereby diverse resources are combined to form a new asset or a less valuable resource is transformed into a more valuable resource. Activities take time for their accomplishment. During the period of time required, the expenditures for the materials, labor, and other resources used in creating the asset must be financed. Financing has a cost. The cost may take the form of explicit interest on borrowed funds, or it may take the form of a return foregone on an alternative use of funds, but regardless of the form it takes, a financing cost is necessarily incurred. *On the premise that the historical cost of acquiring an asset should include all costs necessarily incurred to bring it to the condition and location necessary for its intended use, the Board concluded that, in principle, the cost incurred in financing expenditures for an asset during a required construction or development period is itself a part of the asset's historical acquisition cost.* (emphasis added).

Q. How does the CWIP in rate base approach differ from the GAAP requirement to capitalize carrying costs in the plant costs and then depreciate the plant costs over the useful service life of the asset?

A. The CWIP in rate base approach provides the utility accelerated recovery of the construction financing cost component of total construction costs during the construction period rather than over the service lives of the assets. The CWIP in rate base approach is unique to regulated utilities and is available to a utility only if it is allowed to prematurely recover its construction financing costs during the construction period. On long lead time construction projects, the CWIP in rate base approach may allow a utility to recover 30% or 40% of the total construction costs during the construction period.

The AFUDC approach is consistent with the GAAP requirement to capitalize these construction financing costs and then depreciate the costs over the asset's service life. The recovery occurs over the service life. The revenue requirement is set to recover the depreciation expense plus a return on the declining rate base as the asset is depreciated for book accounting and tax purposes. The AFUDC approach correctly allocates the total cost over the service life of the assets to the customers who are served by the asset.

Q. Is there a penalty to customers under the CWIP in rate base approach?

A. Yes. Under the CWIP in rate base approach, the utility recovers and customers pay the construction financing costs on the related capitalization *plus* the income tax expense on the equity component of the return. This income tax expense then is remitted to the federal and state governments. In other words, this is an unnecessary expense during the construction period imposed on customers that provides no benefit to the utility or to its customers. In fact, it causes an economic harm over the life of the assets on a net present value basis, all else equal.

Q. Describe how the Commission excludes CWIP from either capitalization or rate base for other utilities.

A. The Commission excludes CWIP from either capitalization or rate base for Kentucky Power Company, Duke Energy Kentucky, Inc. (electric and gas), and Columbia Gas of Kentucky, Inc. The Virginia Commission also excludes CWIP from rate base for KU. These utilities and KU in its Virginia jurisdiction capitalize their construction financing costs as AFUDC in the same manner that all other costs are capitalized and added to CWIP during the construction period. They do not recover their construction financing costs during the construction period. Instead, the construction financing costs are recovered after the CWIP is closed to plant-in-service. Thereafter, the utilities earn a return on the related capitalization or rate base and recover the cost through depreciation expense over the service lives of the assets along with a return on the amount included in rate base.

Q. How does the Commission remove the return on CWIP in Kentucky Power Company rate cases?

A. It includes AFUDC in operating income, which effectively eliminates the return on the CWIP included in capitalization. This is referred to as the "AFUDC offset methodology.[21] Methodologically, the Commission calculates AFUDC using the authorized rate of return, net of the income tax expense savings from the interest expense deduction, and includes the net of tax AFUDC in operating income. When

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[21] Direct Testimony of Ranie K. Wohnhas at 22-23 in Case No. 2014-00396. I have attached the relevant pages from the Kentucky Power filing as my Exhibit___(LK-4).

the operating income deficiency or surplus is grossed up to the revenue requirement, the effect of the "AFUDC offset" is a reduction in the revenue requirement equivalent to the grossed-up return times the CWIP balance.

Q. How does the Commission remove the return on CWIP in the Duke rate cases?

A. In its most recent electric base rate case, Duke made a proforma adjustment to remove CWIP from its forecast capitalization.[22]

In its pending natural gas base rate case, Duke proposes a change from capitalization to rate base and simply excluded CWIP from its calculation of rate base.[23] In response to Staff discovery regarding the exclusion of CWIP from rate base, Duke responded:

> Similar to its most recently approved electric rate case, Case No. 2017-00321, Duke Energy Kentucky is not requesting to include recovery of CWIP in base rates because of past Commission precedent that effectively eliminates recovery of a return on CWIP. When CWIP is included in rate base, the Commission has, in past cases, included an AFUDC offset to operating income, which was calculated by multiplying the CWIP balance times the full weighted average cost of capital. The inclusion of the AFUDC offset effectively eliminates any revenue requirement in the test year related to CWIP.[24]

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[22] I have attached the relevant pages from the Duke filing in Case No. 2017-00321 as my Exhibit___(LK-5).

[23] Direct Testimony of Cynthia S. Lee at 6 in Case No. 2018-00261. I have attached the relevant pages from the Duke filing as my Exhibit___(LK-6).

[24] Response to Staff 2-6 in Case No. 2018-00261. I have attached a copy of this response as my Exhibit___(LK-7).

Q. How does the Commission remove the return on CWIP in the Columbia Gas rate cases?

A. In its most recent base rate case, Columbia Gas simply excluded CWIP from its calculation of rate base.[25]

Q. What is your recommendation?

A. I recommend that the Commission exclude CWIP from rate base and direct Atmos to accrue AFUDC starting with the effective date when base rates are reset in this proceeding for ratemaking purposes. I also recommend that the Commission disallow all AFUDC included in plant in service costs that has been accrued for accounting purposes since Atmos was allowed to include CWIP in rate base until the day before the effective date when base rates are reset in this proceeding and it is actually authorized to accrue AFUDC for ratemaking purposes.

The AFUDC approach is beneficial to the Company and its customers. It benefits the Company because it is allowed to capitalize and recover the entirety of its construction financing costs, no more and no less. The AFUDC approach benefits customers because it avoids the premature recovery of these costs during the construction period before the assets provide service, minimizes base rate increases,

[25] Schedule B-4 and the Direct Testimony of Columbia Gas witness Mr. S. Mark Katco at 7-8 in Case No. 2016-00162. I have attached the relevant pages from the Columbia Gas filing as my Exhibit___(LK-8).

and allows customers to pay for these costs over the service lives of the assets when they are used and useful.

The AFUDC approach also avoids the premature recovery of income tax expense from customers under the CWIP approach through the grossed-up rate of return. This unnecessary income tax expense is recovered from customers and then simply remitted to the federal and state governments during the construction period. It benefits neither the Company nor its customers.

Q. What methodology should the Commission use to exclude CWIP from capitalization?

A. I recommend that the Commission use the Duke/Columbia Gas methodology whereby CWIP is simply excluded from rate base, although the Kentucky Power AFUDC offset methodology should yield the same result. The Duke/Columbia Gas methodology simply avoids the AFUDC offset calculation that is necessary if the Kentucky Power AFUDC offset methodology is used.

Q. What is the effect of your recommendation?

A. The effect is a reduction of $3.921 million in the base revenue requirement, although I have not been able to quantify the effect of removing the previously unauthorized AFUDC from plant in service.

D. Cash Working Capital is Overstated Because it Includes Non-Cash Costs in the Lead/Lag Calculations

Q. Describe the Company's request for a cash working capital allowance in rate base.

A. The Company included a cash working capital ("CWC") allowance of $2.693 million using a lead/lag study approach.[26]

Q. Was the lead/lag study performed correctly?

A. No. The Company incorrectly included depreciation expense, deferred income tax expense, and the non-dividend component of the return on equity. The Company also failed to correctly include the dividend component of the return on equity with the correct number of expense lag days.

Q. Why should the lead/lag study exclude non-cash expenses?

A. Fundamentally, the lead/lag study measures the *cash* investment provided by either investors (positive) or customers (negative) on average over the course of the study period. The return on non-cash expenses, such as depreciation and deferred income tax expenses is reflected in the return on rate base. The cash disbursement was made when the construction or acquisition cost was incurred and capitalized as CWIP or plant in service. There will never be a cash disbursement for depreciation or

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[26] Exhibit ATO-CWC1 A attached to Direct Testimony of Joe Christian. I have attached a copy of this schedule as my Exhibit___(LK-9) for ease of reference.

deferred income tax expense. The net accumulated depreciation and accumulated deferred income taxes are subtracted from rate base, but only on a lagged basis. This allows the Company to retain the carrying charge value of these non-cash expenses between rate cases.

The non-dividend component of the return on equity also is non-cash by definition and represents the equity investor's expectation of growth in the value of the utility's stock. Investors are compensated for this component of the return on equity when they sell their stock. The holding period is indefinite.

Q. Is the Company's assumption of 0 expense day lags correct for the non-cash depreciation expense, deferred income tax expense, and non-dividend component of the return on equity?

A. No. These expenses are non-cash expenses and there never will be any cash disbursements. The Company used 0 expense lag days for these expenses. Translated, that means that the Company assumes these non-cash expenses actually will be paid in cash the second they are incurred. Nothing could be further from the truth. The correct expense lag days for never is infinity, which necessarily is greater than the revenue lag days.

Q. Is the dividend component of the return on equity a cash expense?

A. Yes. The discounted cash flow ("DCF") model, used by Company witness Dr. Vander Weide, and historically relied on by the Commission to determine the return on equity, is comprised of both the dividend return and projected growth in the stock price. Atmos pays dividends quarterly. For the dividend component of the return on equity, an expense lag of 118.6 days is required, not the 0 days asserted by the Company. The Company does not immediately pay the dividend the second this cost is incurred and recognized in the revenue requirement. To the contrary, the service period each quarter is 45.6 days (365 days divided by 4 divided by 2). Atmos typically pays its quarterly dividends approximately nine weeks after the end of the quarter. Atmos paid its last dividend on December 12, 2018, 73 days after the end of the fourth quarter in its fiscal year 2018.[27] Thus, the dividend component of the return on equity expense lag days is 118.6 days, consisting of the 45.6 days for the service period plus the 73 days payment lag.

Q. What is your recommendation?

A. I recommend that the Commission set the Company's cash working capital at negative $5.503 million based on the lead/lag study filed by the Company adjusted to remove the non-cash expenses, including depreciation expense, deferred income tax expense, and the non-dividend component of the return on equity, and adjusted to include 118.6 expense lag days for the dividend component of the return on equity.

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[27] https://www.nasdaq.com/symbol/ato/dividend-history.

This is a reduction of $8.195 million compared to the Company's proposed cash working capital.

Q. Have you quantified the effect of your recommendation?

A. Yes. The effect is to reduce the revenue requirement by $0.821 million.

IV. COST OF CAPITAL ISSUES

A. Summary of Forecast Capital Structure and Cost of Capital

Q. Describe the Company's proposed cost of capital.

A. The Company proposes the following forecast capital structure and costs for each component.

As Filed in Case No. 2018-00281

	Capital Ratio	Component Costs	Weighted Avg Cost
Short Term Debt	3.44%	2.40%	0.08%
Long Term Debt	38.31%	4.72%	1.81%
Common Equity	58.24%	10.40%	6.06%
Total Capital	100.0%		7.95%

Q. How does the Company's forecast capital structure in this proceeding compare to the capital structure authorized in Case No. 2017-00349?

A. It reflects an extreme increase in the common equity ratio in addition to the proposed substantial increase in the return on equity. The Commission approved the following capital structure and costs for each component in the prior proceeding:

Authorized in Case No. 2017-00349

	Capital Ratio	Component Costs	Weighted Avg Cost
Short Term Debt	3.48%	1.66%	0.06%
Long Term Debt	43.95%	5.09%	2.24%
Common Equity	52.57%	9.70%	5.10%
Total Capital	100.0%		7.41%

Q. Is the increase in the common equity ratio reasonable?

A. No. It is unreasonable and unnecessarily and significantly increases the cost of capital and base revenue requirement, as well as the PRP Rider revenue requirement. The cost of equity is significantly greater than the cost of any other component of the capital structure. In addition, the cost of common equity must be grossed-up for income taxes, making it even more costly than it appears.

Q. What is the average common equity ratio for the comparable group used by Dr. Vander Weide to develop his recommendation for the return on equity?

A. The average common equity ratio for the comparable group is 53%. Even this common equity ratio is overstated due to Dr. Vander Weide's use of Chesapeake Utilities in his comparative group with a common equity ratio of 71.1%, clearly an extreme outlier that should be excluded from the comparative group in calculating the average common equity ratio.

Q. What is your recommendation?

A. I recommend that the Commission reject the Company's proposed capital structure and cap the common equity at 54.3%, after adjustment for the new debt issuance that the Company failed to include, although I consider even this common equity ratio to be at the high end of a reasonable range. In any event, the 54.3% common equity ratio is well within the Company's stated "desired capital structure with an equity-to-capitalization ratio between 50% and 60%, inclusive of long-term and short-term debt."[28]

The Company's forecast common equity ratio is excessive and the long-term debt ratio is too low. One reason for this absurd capital structure is the Company's failure to include the significant long-term debt issuance in October 2018. As I will describe in the next section of my testimony, the Company was aware of this planned issuance when it made its filing, but inexplicably failed to include it. The Commission can judge whether this was intentional or not.

[28] Response to AG 1-20. I have attached a copy of this response as my Exhibit___(LK-10).

<u>B. Reflect October 2018 Long-Term Debt Issuance in Capital Structure and Cost of Debt</u>

Q. Describe the Company's issuance of long-term debt in October 2018.

A. On October 4, 2018, the Company issued $600 million in senior notes at 4.30% due in 2048.[29]

Q. Did the Company include this issuance of long-term debt in its forecast cost of capital?

A. No. The Company made its filing in this proceeding on September 28, 2018, but failed to include this debt issuance even though it was clearly in process and known. This is a significant omission. The Company did include a separate forecast debt issuance of $450 million on March 15, 2019. The AG asked the Company in discovery if it was aware of the planned October 2018 debt issuance when it made its filing in this proceeding, and more specifically, whether Mr. Christian was aware of the planned financing when he drafted his testimony. The Company did not answer this question directly and failed to deny that it knew that it would issue this debt less than a week after its filing.[30] In my experience, the failure to include the effects of a known financing in a forecast capital structure is highly unusual and questionable.

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[29] Atmos 2018 10-K at 58. I have attached a copy of the relevant pages as my Exhibit___(LK-11).
[30] Response to AG 2-20.

Q. What is the effect of correctly including this new issuance of long-term debt in the capital structure and cost of debt?

A. It reduces the common equity to a reasonable level, albeit greater than the percentage reflected in the capital structure in the prior case, and reduces the average cost of long-term debt. I have corrected the capital structure and cost of long-term debt to reflect this actual new long-term debt issuance. The following table shows the revised capital structure, cost of long-term debt and the cost of capital:

As Filed Case No. 2018-00281 Including October 4, 2018 Issuance

	Capital Ratio	Component Costs	Weighted Avg Cost
Short Term Debt	3.21%	2.40%	0.08%
Long Term Debt	42.47%	4.66%	1.98%
Common Equity	54.32%	10.40%	5.65%
Total Capital	100.0%		7.71%

Q. What is the effect on the Company's base revenue requirement?

A. The effect is a reduction of $1.256 million in the base revenue requirement.

C. Reduce Cost of Forecast March 2019 Long-Term Debt Issuance to Reflect Current 30-Year Treasury Yield

Q. Describe the Company's forecast long-term debt issuance and retirement of a maturing long-term debt issuance on March 15, 2019.

A. The Company forecasts a new long-term debt issuance of $450 million plus another $63 million for credit swap instruments (total of $513 million) at 5.07% and a reduction of $450 million for the retirement of a matured senior note at 8.5%.[31]

Q. How did the Company forecast the proposed 5.07% interest rate?

A. The Companies used a forecast rate of 3.782% for the 30-year Treasury yield and added 1.00% for the credit spread and added another 0.292% for issuance fees.[32]

Q. Is the forecast rate of 3.782% for the 30-year Treasury yield reasonable?

A. No. The 30-year Treasury yield is presently 3.1%.[33]

Q. What is your recommendation?

A. I recommend that the Commission use a forecast interest rate of 4.392% for the new debt issue, consisting of 3.1% for the present 30-year Treasury yield plus the Company's proposed credit spread of 1.0% plus the Company's estimated fees of 0.292%.

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[31] Schedule J-3F.

[32] Responses to AG 1-15 and Staff 1-64 attachment file "Staff_1-64_Att1 – Christian WP – Hypothetical Refinance 03-2019.xlsx. I have a attached a copy of both responses as my Exhibit___(LK-12).

[33] Wall Street Journal January 10, 2019.

Q. What is the effect of your recommendation?

A. The effect is a reduction of $0.132 million in the Company's base revenue requirement, using the rate base after my recommended adjustments.

D. Reduce Requested Return on Equity

Q. Have you performed an independent study of the required return on equity?

A. No. The AG did not retain an expert to perform an independent study of the required return on equity.

Q. Have you reviewed the testimony of Company witness Dr. James Vander Weide?

A. Yes. Dr. Vander Weide recommends a return on equity of 10.40%. Dr. Vander Weide utilized various methodologies to develop his recommendation, including the discounted cash flow, capital asset pricing model ("CAPM"), and ex ante and ex post risk premium. In addition, he added flotation costs to the results derived from these methodologies.

Q. What methodology has the Commission historically relied on for the return on equity?

A. The Commission historically has relied on the DCF methodology and has not relied on the results of the CAPM, risk premium, or other methodologies. More recently, the Commission has cited and given consideration to the returns on equity allowed by other regulatory commissions as a guide to the required rate of return. Further, the Commission historically has rejected utility requests to add flotation costs to increase the required rate of return.[34]

Q. What is the average of Dr. Vander Weide's DCF results without flotation costs?

A. The average for his comparative group is 9.1% without flotation costs.[35] This average includes One Gas, Inc., which has a forecast growth rate of 12.0%, more than twice the growth rate of the other utilities in the comparative group, and a DCF result of 16.0%, well outside the range of 6.9% to 10.2% for the other utilities in the comparative group.[36]

Q. How do Dr. Vander Weide's DCF results compare to other recently authorized returns on equity?

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[34] See Case No. 2017-00321, Order dated Apr. 13, 2018, at 39.
[35] Response to Staff 2-54(c). I have attached a copy of this response as my Exhibit___(LK-13).
[36] Attachment to Response to Staff 2-47. I have attached a copy of this response as my Exhibit___(LK-14).

A. The average actual authorized gas returns on equity in general rate cases decided in 2017 was 9.72% and decided from January 2018 through September 2018 was 9.62%.[37]

Q. What is your recommendation?

A. I recommend that the Commission simply continue the present authorized 9.7% return on equity. This return is well in excess of Dr. Vander Weide's DCF results without flotation costs, but is consistent with recently authorized returns for other gas utilities in 2017 and 2018.

Q. What are the effects of your recommendation?

A. The effect is a reduction of $1.685 million in the Company's base revenue requirement, using the rate base after my recommended adjustments. This amount is incremental to the reductions in the revenue requirement for my recommendations on the cost of long-term debt and the cost of short-term debt.

Q. Have you quantified the effects of a 1.0% change in the return on common equity?

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[37] KU response to Staff 2-39 in Case No. 2018-00294. I have attached a copy of this response as my Exhibit___(LK-15).

A. Yes. Each 1.0% return on equity equals $2.407 million in the base revenue requirement.

V. DIVISION 002 AND DIVISION 091 COMPOSITE FACTORS

Q. Please describe the composite factors used to allocate Atmos' shared services costs incurred at the corporate office division (002) and the Kentucky/Mid-States division (091) that are allocated to Kentucky.

A. Costs that are incurred at the corporate office division are allocated to the Kentucky/MidStates Division in the filing using a composite factor. The costs allocated from the corporate office division to the Kentucky/MidStates Division, along with the costs incurred directly by the Kentucky/MidStates division, are subsequently allocated to Kentucky using another composite factor. The Company calculates the composite factors using three equally weighted components for each division that receives an allocation of its costs: gross direct property plant and equipment, average number of customers, and total O&M expense.[38] Atmos uses various versions of the composite factor, e.g., all companies, utility, and regulated only, among others, to allocate costs from the corporate office division.

In the filing, Atmos calculated a composite factor of 10.40% and allocated costs from Division 002 to Division 091 using this factor. Atmos calculated a composite factor of 5.18% and allocated the Division 002 costs allocated to Division

[38] Refer to Exhibit GKW-1 attached to Mr. Waller's Direct Testimony. The calculations were provided electronically in response to Staff 2-37 and WP FY17_Composite_Factors_for_Rates_Final.

091, along with the costs incurred directly by Division 091, to the Kentucky jurisdiction using this factor.

Q. Are the composite factors used for Division 002 and Division 091 reasonable?

A. No. Only one of the three components of the composite factor is reasonable, the gross direct property plant and equipment. The number of customers is not reasonable because customer costs are incurred in a separate *Call Center* customer support division (012). The costs of Division 012 are appropriately allocated to Kentucky using a separate customer allocation factor. The total O&M is not reasonable because it is not a comprehensive measure of all expenses that are managed by Division 002.

Q. In lieu of the number of customers and total O&M expenses as components of the composite factor, is there a better and more comprehensive measure of the expenses that are incurred by the corporate office division?

A. Yes. Total operating expenses is a better and more comprehensive measure of all costs. In addition to O&M expenses, it includes taxes other than income taxes and depreciation and amortization expenses.

Q. Do the two factors, gross direct property plant and equipment and the total operating expenses provide a comprehensive proxy for all of the costs that are

incurred and managed by Division 002?

A. Yes. The gross direct property plant and equipment is a reasonable proxy for rate base and the total operating expenses are a reasonable proxy for the operating expenses included in the filing.

Q. What is your recommendation?

A. I recommend that the Commission modify the composite factor so that it is based on an equal weighting of gross direct property plant and equipment and total operating expenses. This will improve the composite factor so that it provides an allocation to Kentucky based on a comprehensive measure of the corporate office and Kentucky/MidStates management and provision of services to Kentucky.

Q. Have you quantified the effect of your recommendation?

A. Yes. The effect is to reduce the revenue requirement by $0.725 million.[39]

Q. Does this complete your testimony?

A. Yes.

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

BEFORE THE

PUBLIC SERVICE COMMISSION OF THE

COMMONWEALTH OF KENTUCKY

IN RE:	**APPLICATION OF ATMOS ENERGY**	**)**	
	CORPORATION FOR AN	**)**	**CASE NO. 2018-00281**
	ADJUSTMENT OF RATES AND	**)**	
	TARIFF MODIFICATIONS	**)**	

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF

THE OFFICE OF THE ATTORNEY GENERAL

J. Kennedy and Associates, Inc.
570 Colonial Park Drive, Suite 305
Roswell, GA 30075

JANUARY 28, 2019

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
28th day of January 2019.

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2019
CHEROKEE COUNTY, GEORGIA

EXHIBIT ____ (LK-1)

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

Luther Rice University, MA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

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

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present: **J. Kennedy and Associates, Inc.:** Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Maryland, Minnesota, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, West Virginia and Wisconsin state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986: **Energy Management Associates:** Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983: **The Toledo Edison Company:** Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

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

CLIENTS SERVED

Industrial Companies and Groups

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

Regulatory Commissions and Government Agencies

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

RESUME OF LANE KOLLEN, VICE PRESIDENT

Utilities

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

**Expert Testimony Appearances
of
Lane Kollen
As of January 2019**

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

**Expert Testimony Appearances
of
Lane Kollen
As of January 2019**

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

**Expert Testimony Appearances
of
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As of January 2019**

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

Expert Testimony Appearances
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Lane Kollen
As of January 2019

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

**Expert Testimony Appearances
of
Lane Kollen
As of January 2019**

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

Expert Testimony Appearances
of
Lane Kollen
As of January 2019

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

Expert Testimony Appearances
of
Lane Kollen
As of January 2019

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

Expert Testimony Appearances
of
Lane Kollen
As of January 2019

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

Expert Testimony Appearances
of
Lane Kollen
As of January 2019

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

Expert Testimony Appearances
of
Lane Kollen
As of January 2019

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

Expert Testimony Appearances
of
Lane Kollen
As of January 2019

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

Expert Testimony Appearances
of
Lane Kollen
As of January 2019

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

Expert Testimony Appearances
of
Lane Kollen
As of January 2019

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

Expert Testimony Appearances
of
Lane Kollen
As of January 2019

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

Expert Testimony Appearances
of
Lane Kollen
As of January 2019

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

**Expert Testimony Appearances
of
Lane Kollen
As of January 2019**

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

Expert Testimony Appearances
of
Lane Kollen
As of January 2019

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

Expert Testimony Appearances
of
Lane Kollen
As of January 2019

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

**Expert Testimony Appearances
of
Lane Kollen
As of January 2019**

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

**Expert Testimony Appearances
of
Lane Kollen
As of January 2019**

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

Expert Testimony Appearances
of
Lane Kollen
As of January 2019

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

Expert Testimony Appearances
of
Lane Kollen
As of January 2019

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

**Expert Testimony Appearances
of
Lane Kollen
As of January 2019**

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

Expert Testimony Appearances
of
Lane Kollen
As of January 2019

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

Expert Testimony Appearances
of
Lane Kollen
As of January 2019

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

Expert Testimony Appearances
of
Lane Kollen
As of January 2019

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

Expert Testimony Appearances
of
Lane Kollen
As of January 2019

Date	Case	Jurisdict.	Party	Utility	Subject
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	UP Settlement benefits and damages.
05/14	PUE-2013-00132	VA	HP Hood LLC	Shenandoah Valley Electric Cooperative	Market based rate; load control tariffs.
07/14	PUE-2014-00033	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting, change in FAC Definitional Framework.
08/14	ER13-432 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
08/14	2014-00134	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Requirements power sales agreements with Nebraska entities.
09/14	E-015/CN-12-1163 Direct	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class cost allocation.
10/14	2014-00225	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Allocation of fuel costs to off-system sales.
10/14	ER13-1508	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy service agreements and tariffs for affiliate power purchases and sales; return on equity.
10/14	14-0702-E-42T 14-0701-E-D	WV	West Virginia Energy Users Group	First Energy-Monongahela Power, Potomac Edison	Consolidated tax savings; payroll; pension, OPEB, amortization; depreciation; environmental surcharge.
11/14	E-015/CN-12-1163 Surrebuttal	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class allocation.
11/14	05-376-EL-UNC	OH	Ohio Energy Group	Ohio Power Company	Refund of IGCC CWIP financing cost recoveries.

Expert Testimony Appearances
of
Lane Kollen
As of January 2019

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

Expert Testimony Appearances
of
Lane Kollen
As of January 2019

Date	Case	Jurisdict.	Party	Utility	Subject
07/15	EL10-65 Direct and Answering Consolidated Bandwidth Dockets	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback ADIT, Bandwidth Formula.
09/15	14-1693-EL-RDR	OH	Public Utilities Commission of Ohio	Ohio Energy Group	PPA rider for charges or credits for physical hedges against market.
12/15	45188	TX	Cities Served by Oncor Electric Delivery Company	Oncor Electric Delivery Company	Hunt family acquisition of Oncor; transaction structure; income tax savings from real estate investment trust (REIT) structure; conditions.
12/15 01/16	6680-CE-176 Direct, Surrebuttal, Supplemental Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Need for capacity and economics of proposed Riverside Energy Center Expansion project; ratemaking conditions.
03/16 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.
05/16	2016-00026 2016-00027	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Need for environmental projects, calculation of environmental surcharge rider.
05/16	16-G-0058 16-G-0059	NY	New York City	Keyspan Gas East Corp., Brooklyn Union Gas Company	Depreciation, including excess reserves, leak prone pipe.
06/16	160088-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Fuel Adjustment Clause Incentive Mechanism re: economy sales and purchases, asset optimization.

**Expert Testimony Appearances
of
Lane Kollen
As of January 2019**

Date	Case	Jurisdict.	Party	Utility	Subject
07/16	160021-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Revenue requirements, including capital recovery, depreciation, ADIT.
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.
03/17	2016-00370 2016-00371	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	AMS, capital expenditures, maintenance expense, amortization expense, depreciation rates and expense.
06/17	29849 (Panel with Philip Hayet)	GA	Georgia Public Service Commission Staff	Georgia Power Company	Vogtle 3 and 4 economics.

**Expert Testimony Appearances
of
Lane Kollen
As of January 2019**

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

Expert Testimony Appearances
of
Lane Kollen
As of January 2019

Date	Case	Jurisdict.	Party	Utility	Subject
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.

EXHIBIT ____ (LK-2)

REQUEST:

Refer to Atmos' response to PSC Staff DR 2-01 (a)-(c), in case number 2017-00308, wherein the Company states that it proposed the PRP program because the "bare steel pipe had been in the ground approximately 50-75 years" and that "the ultimate goal of the Company's PRP program is the accelerated replacement of aging infrastructure that has outlived its useful life."

a. Is Atmos in control of capital expenditures, such as when it replaces infrastructure? If not, who controls the capital expenditures of Atmos? The PSC?

b. If the answer to (a), above, is that Atmos is the entity that controls its capital expenditures, then why should customers pay more for accelerated replacement of pipe, when it was Atmos that allowed so much infrastructure to "outlive[] its useful life?"

c. If the answer to (a), above, is that any other entity or body controls Atmos' capital expenditures, why should the Commission allow such control?

d. Confirm that the Company believes the singular purpose of the PRP is the accelerated replacement of aging infrastructure that has outlived its useful life and/or poses a possible safety and/or reliability concern.

e. Where does Atmos find support for "reliability concern" being a determining factor for inclusion through the Company's PRP?

f. Does the Company believe it must be incentivized to replace aging or unsafe infrastructure with mechanism such as the PRP? If not, then explain the statement, "the accelerated replacement of aging infrastructure allows the Company to modernize its distribution system."

g. What preempts Atmos' ability to adequately replace aging or unsafe infrastructure without the use of the PRP.

h. Confirm that the purpose of the PRP is to expedite the recovery of costs.

RESPONSE:

a) Yes, To the extent its level of investment ensures compliance with federal, state and local regulations, Atmos Energy manages the pace with which investment is made in infrastructure replacement as well as all other capital investment. The Company strives to be the safest provider of natural gas service and will always operate a safe and reliable service.

b) The Company disagrees with the premise of the question. The method of replacement through its pipeline replacement program (PRP) benefits the customer by permitting obsolete infrastructure to be removed at an accelerated pace in an efficient manner. Please note that the Company's PRP is allowed by Kentucky statute, KRS 278.509. According to the American Gas Association, forty-one (41) states including the District of Columbia have specific rate mechanisms that foster accelerated replacement of pipelines no longer fit for service. While the Company's PRP does accelerate the replacement of aging infrastructure, it is a safety program. Atmos Energy is one of many utilities to have a PRP in Kentucky or the United States. The Company is replacing aging infrastructure to be proactive in modernizing its system. Providing safe and reliable gas service to all of its customers is Atmos Energy's most fundamental objective. The Company is acutely aware that its actions can directly impact the safety of its customers, communities and employees. The importance of focusing on safety is magnified when one considers the natural gas incidents that have resulted in loss of life, injuries, and damage to property.

c) Not applicable.

d) Deny, the PRP has more than a "single purpose". The Company can confirm that one purpose of the PRP is to provide a benefit to the customer by accelerating replacement of aging infrastructure that poses a possible safety and/or reliability concern in a manner that is more efficient than replacement and recovery through litigated rate case proceedings.

e) Please refer to the Commission's Order in Case No. 2014-00274 in which the Company listed safety and reliability concerns as reasons for the replacement of the Shelbyville Line within the Company's PRP.

f) As stated above, the Company strives to be the safest provider of natural gas service and the Company's PRP is a safety program which is allowed by statute. The incentive of the PRP is to replace aging infrastructure on a more proactive basis creating a more modern system that is both safer and more reliable. Bare steel pipe is prone to failure over time. The number one cause of leaks on bare steel pipe is corrosion and once the corrosion process has started, corrosion will continue until the pipe fails. As a result of these concerns, the accelerated replacement of pipes made of bare steel materials is reasonable and prudent and such pipes and services should be replaced as expeditiously as possible to ensure the system remains safe.

g) As stated above, the Company's PRP is allowed by statute and is a more efficient method of investment/recovery than investment/recovery through litigated rate proceedings and thus more beneficial to the customer than recovery through litigated proceedings. This more efficient recovery is also in line with advice from state and federal regulators. In a letter to the National Association of State Regulatory Commissions ("NARUC"), the Pipeline and Hazardous Materials Safety Administration ("PHMSA") administrator stated, "[W]e appreciate the NARUC's continued diligence in promoting rate mechanisms that will encourage and enable pipeline operators to take reasonable measures to repair, rehabilitate or replace high-risk gas pipeline infrastructure." PHMSA further requests NARUC's "support in ensuring that [state] commissions implement effective programs for the timely repair, replacement, and rehabilitation of high-risk gas pipeline infrastructure."

In response to fatal explosions caused by natural gas pipeline failures in Allentown, Pennsylvania and San Bruno, California, the Secretary of Transportation Ray LaHood issued a Call to Action. The Call to Action called on pipeline operators and owners to review their pipelines and quickly repair and replace sections in poor condition. NARUC responded by issuing a resolution encouraging "regulators and industry to consider sensible programs aimed at replacing the most vulnerable pipelines as quickly as possible along with the adoption of rate recovery mechanisms that reflect the financial realities of the particular utility in question" and further encouraging state commissions to "consider adopting alternative rate recovery mechanisms as necessary to accelerate the modernization, replacement and expansion of the nation's natural gas pipeline systems." Consistent with these calls to action, in Proceeding No. 2009-00354, Atmos Energy proposed the PRP to provide timely recovery of safety and reliability investments and to help reduce the frequency of base rate proceedings.

h) Confirm. While the recovery of costs is a benefit of the PRP, the primary purpose of the PRP, which is allowed by statute, is to replace aging infrastructure on a more proactive basis creating a more modern system that is both safer and more reliable.

Respondents: Mark Martin and Greg Waller

EXHIBIT ____ (LK-3)

REQUEST:

Refer to the Attachment 1 Excel spreadsheet file included with the response to Staff 2-15. Refer further to worksheet tabs "CWIP Ending Balances" and "Monthly Additions to CWIP." Refer further to the Company's breakdown of "CWIP Without AFUDC" and "CWIP AFUDC" provided on the spreadsheet KY_Plant_Data-2018-case.

a. Provide a sum of the monthly AFUDC amounts added to plant for each month during 2017 as found in column h of the "Monthly Additions to CWIP" worksheet tab.

b. Provide the fiscal year end balances of KY Division CWIP included in the worksheet tab "CWIP Ending Balances" for each year 2014 through 2018.

c. Confirm that the amounts included for KY Division CWIP Without AFUDC and CWIP AFUDC provided on the spreadsheet KY_Plant_Data-2018-case as of December 31, 2017 were $32,043,565 and $255,946, respectively, and the amounts projected throughout the test year were $38,154,809 and $581,994, respectively.

d. Refer to the "Monthly Additions to CWIP" worksheet tab. For the month of December 2017, provide the plant balances per project number, the AFUDC rate (annual and monthly), and the computed AFUDC by project that sums to the $68,465.90 in AFUDC amounts added to CWIP found in column h cell rows 56270-56341 for the month of December 2017. If the plant balances accruing AFUDC provided in response to subpart (b) is much higher than the amount of $255,946 cited for December 2017, explain why.

e. Confirm that there is no addition to operating income applicable to AFUDC in the Company's filing. If not confirmed, explain. If confirmed, explain why there is not such an addition.

f. Provide the Company's rationale used to record AFUDC each month to include a description of which types of projects accrue AFUDC and the basis for the rate applied.

g. For the following project numbers listed in the "Monthly Additions to CWIP" worksheet tab applicable to December 2017, provide a project name and description and explain why each had AFUDC accrued:

Project Number	AFUDC Added in Dec 2017
050.44080	$13,557.35
050.44133	$22,054.37
050.44145	$11,396.84
050.45376	$3,270.31
050.46079	$2,679.68
050.46537	$3,060.55

RESPONSE:

a) The data necessary to perform the requested analysis is included in the referenced attachment. Please see Attachment 1 to the Company's response to Staff DR No. 2-15, tab labeled "Monthly Additions to CWIP" and filter column G to "AFUDC."

b) The data necessary to perform the requested analysis is included in the referenced attachment. Please see Attachment 1 to the Company's response to Staff DR No. 2-15, tab labeled "CWIP Ending Balances" and filter on September of each Fiscal Year (the column labeled "Month Ending Balance" where the last two digits are "09").

c) Confirm.

d) Project balances in CWIP can be found on the "CWIP Ending Balances" tab. The AFUDC amount provided by the Company in Attachment 1 to the Company's response to Staff DR No. 2-15, tab labeled "Monthly Additions to CWIP" is the amount (by project) of AFUDC computed for the month of Dec-17 only. The $255,946 of AFUDC provided in response to subpart (b) and excluded from rate base is the total balance of AFUDC accrued as of Dec-17 on Projects with Open CWIP as of Dec-17. Please see also the Company's responses to AG DR Nos. 2-05 and 2-07.

e) Confirm. However, the Company has removed a balance of $581,994 of AFUDC from CWIP prior to inclusion of CWIP in rate base consistent with the CWIP forecast methodology described in the testimony of Greg Waller. Please see the relied upon file "KY Plant Data - 2018 Case", "Gross Plant" tab on Excel row 222. This methodology is the same methodology that was included in the revenue requirement approved in the Company's 2013, 2015 and 2017 general rate cases.

f) Please see Company's response to AG DR No. 2-05

g) Please see Company response to subpart (f).

Project Number	Project Name	Project Description	Criteria
050.44080	PRP.2637.Lake - City	Lake City, PRP: Replacement of Approximately 2 miles of vintage steel gas main along KY Hwy 453.	Meets AFUDC Criteria
050.44133	PRP.2635.Marion to Fredonia	PRP Replacement of approximately 46,700 feet of vintage gas main along S Main Street in Crittenden and Caldwell County Kentucky	Meets AFUDC Criteria
050.44145	PRP.2738.Springfield Calvary	PRP Replacement of approximately 80,500 feet of vintage gas transmission main with high pressure distribution in Marion and Washington County Kentucky.	Meets AFUDC Criteria

050.45376	PRP.2736.Kirkman-Liberty	Replace 17,791 ft of bare 2 Inch & 4 Inch LP steel with 9,256 ft of 2 Inch PE and 8,535 ft 4 Inch PE IP Replace 263 services.	Meets AFUDC Criteria
050.46079	2734.McGinnis QuarryTGT.Tap	Pipeline interconnect and system reinforcement to the northeast side of Bowling Green, KY serving several large volume customers. Texas Gas (TGT) shall provide, at Atmos Energy's expense, labor, equipment and materials necessary to construct, install, operate and maintain an 8" x 4" tap and riser on Index BGM 8-1's 8" pipeline at or about MP 8+4970. TGT shall also install, operate, maintain and not own a 4" Ultrasonic meter skid, all as authorized by Interconnect Agreement. Atmos Energy shall at its own expense, provide any required land access, ingress & egress rights, all weather road, install appropriate sized/redundant OPP, curtailment capabilities and any such other equipment (collectively, "Facilities") as necessary to connect to BWP's system. Atmos Energy shall also utilize Boardwalk approved vendors per the ICA. Tax gross-up is calculated on the tap, valves and riser, the client will own all other facilities down stream of BWP's riser. BWP shall be deemed the Measuring Party	Meets AFUDC Criteria
050.46537	2739.Waddy Line Ph 2	FY18/19 Budgeted System Improvement project occurring in Shelby County, KY. Replacing 25,000 feet of 6" high pressure steel main with 12" high pressure steel main. Starting R/W preparation and completion of easement acquisition in October FY18. Starting construction in July FY18 and completing in March FY19. 20 services will be replaced. Contractor labor will be utilized for construction and inspection.	Meets AFUDC Criteria

Respondent: Greg Waller

EXHIBIT ____ (LK-4)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For: (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2014 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; And (4) An Order Granting All Other Required Approvals And Relief	)))))))	**Case No. 2014-00396**

DIRECT TESTIMONY OF

RANIE K. WOHNHAS

ON BEHALF OF KENTUCKY POWER COMPANY

Amortization of Intangible Plant
(Section V, Exhibit 2, Adjustment W38)

Q. WHY IS INTANGIBLE PLANT AMORTIZATION ANNUALIZED?

A. The Company annualized the September 30, 2014 monthly intangible plant amortization expense and compared the result with the level of intangible plant amortization expense included in the test year. The annualized value better represents the on-going level of expense for intangible plant amortization expense. The effect of this adjustment is to increase Kentucky Power's depreciation expense and decrease the deferred taxes, as explained by Witness Bartsch, by $209,475 and $73,316 respectively.

Interest Synchronization Adjustment
(Section V, Exhibit 2, Adjustment W48)

Q. WHY IS AN INTEREST SYNCHRONIZATION ADJUSTMENT NECESSARY?

A. The purpose of this adjustment is synchronize the capital costs and capital structure included by the Company in this filing with the Federal and State Income Taxes included in the test period cost of service and the interest expense tax deduction that will result. The adjustment resulted in an increase to state income tax of $311,143 and an increase to federal income tax of $1,790,035 for a total increase to expenses of $2,101,178.

AFUDC Offset Adjustment
(Section V, Exhibit 2, Adjustment W52)

Q. PLEASE EXPLAIN THE AFUDC OFFSET ADJUSTMENT.

A. The September 30, 2014 balance of Construction Work In Progress ("CWIP") was used in the determination of Rate Base. The adjustment eliminates all CWIP related to Big Sandy in compliance with the Stipulation and Settlement Agreement. All AFUDC related to Big Sandy is also eliminated. Consistent with prior Commission practice for the Company, an Allowance for Funds Used During Construction (AFUDC) "offset" adjustment is being made to record AFUDC above the line. The non-Big Sandy CWIP balance was $76,287,594 on September 30, 2014, of which $2,007,095 is not subject to AFUDC. The remaining balance of $74,280,499 is subject to AFUDC. Using the requested overall return of 7.71%, the annualized AFUDC is $5,664,029. The AFUDC booked during the test year was $5,521,834 requiring an adjustment to increase the AFUDC offset by $250,424. The Deferred Federal Income Taxes (DFIT) associated with the borrowed funds portion of the $5,664,029 is $748,162. The booked DFIT on the borrowed funds portion was $658,123. This increases DFIT by $90,039.

VIII. TARIFF REVISIONS

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

Q. IS THE COMPANY PROPOSING ANY MODIFICATIONS TO THE TREATMENT OF SYSTEM SALES OR TARIFF S.S.C. IN THIS PROCEEDING?

A. Yes. First, as has been the practice in past cases, the Company proposes to update the system sales margin amount included as a credit in base rates. This updated system sales margin amount is reflected in Tariff S.S.C., the System Sales Clause. Company Witness Vaughan describes the derivation of the proposed updated system sales margin base rate credit amount in his testimony. The Company is

EXHIBIT ____ (LK-5)

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2017-00321
OVERALL FINANCIAL SUMMARY
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2017
FOR THE TWELVE MONTHS ENDED MARCH 31, 2019

DATA: "X" BASE PERIOD "X" FORECASTED PERIOD
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NO(S).: SEE BELOW

SCHEDULE A
PAGE 1 OF 1
WITNESS RESPONSIBLE:
S. E. LAWLER

LINE NO.	DESCRIPTION	SUPPORTING SCHEDULE REFERENCE	JURISDICTIONAL REVENUE REQUIREMENTS BASE PERIOD	FORECASTED PERIOD
1	Capitalization Allocated to Electric Operations	WPA-1a, 1c	565,195,503	705,051,140
2	Operating Income	C-2	36,387,908	20,091,071
3	Earned Rate of Return (Line 2 / Line 1)		6.438%	2.850%
4	Rate of Return	J-1	7.208%	7.083%
5	Required Operating Income (Line 1 x Line 4)		40,739,292	49,938,772
6	Operating Income Deficiency (Line 5 - Line 2)		4,351,384	29,847,701
7	Gross Revenue Conversion Factor	H	1.6298147	1.6298147
8	Revenue Deficiency (Line 6 x Line 7)		7,091,950	48,646,222
9	Revenue Increase Requested	C-1	N/A	48,646,213
10	Adjusted Operating Revenues	C-1	N/A	308,857,946
11	Revenue Requirements (Line 9 + Line 10)		N/A	357,504,159

DUKE ENERGY KENTUCKY, INC.
ELECTRIC DEPARTMENT
CASE NO. 2017-00321
DATA: BASE PERIOD "X" FORECASTED PERIOD
CALCULATION OF JURISDICTIONAL CAPITALIZATION

WPA-1c
WITNESS RESPO
S. E. LAWLER

Line No.	Description		Capitalization Total	Capitalization Electric
1	Total Forecasted Period Capitalization	(1)	1,069,192,372	
2				
3	Less: Gas Non-jurisdictional Rate Base	(2)	5,927,796	
4	Electric Non-jurisdictional Rate Base	(2)	792,644	
5	Non-jurisdictional Rate Base	(2)	(50,651,286)	
6				
7				
8	Jurisdictional Capitalization		1,113,123,218	
9				
10	Electric Jurisdictional Rate Base Allocation %	(2)	72.045%	801,949,623
11				
12	Plus: Jurisdictional Electric ITC	(3)		4,354,475
13	Less: CWIP	(4)		(85,525,336)
14	Plant in Service included in ESM	(5)		(15,727,622)
15				
16	Total Allocated Capitalization			705,051,140

To Sch. A

Notes:
(1) Schedule J-1, page 2.
(2) WPA-1d.
(3) Schedule B-6, page 2.
(4) Schedule B-4. The Company is not requesting to include recovery of CWIP in base rates.
(5) The Company will recover this plant in service through the Environmental Surcharge Mechanism

EXHIBIT ____ (LK-6)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Natural Gas Rates; 2) Approval of a Decoupling Mechanism; 3) Approval of New Tariffs; and 4) All Other Required Approvals, Waivers, and Relief.	)))))))	Case No. 2018-00261

DIRECT TESTIMONY OF

CYNTHIA S. LEE

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

August 31, 2018

each major property grouping. It also shows the proposed depreciation and amortization accrual rate, calculated annual depreciation and amortization expense, percentage of net salvage value, average service life and curve form, as applicable for each account. The calculated annual depreciation and amortization was determined by multiplying the 13-month average adjusted jurisdictional plant investment for the forecast period by the proposed depreciation and amortization accrual rates.

With this filing, the Company proposes depreciation and amortization accrual rates prepared in 2018 and sponsored by Mr. Spanos of Gannett Fleming, Inc., who prepared the depreciation study. The account numbers referred to in the depreciation study were those in effect in 2018 for Duke Energy Kentucky. The Company requests that the Commission approve these new depreciation and amortization accrual rates included in this filing and that the depreciation and amortization accrual rates be effective April 1, 2019, corresponding with the effective date of the natural gas rates established in this case.

Q. PLEASE DESCRIBE SCHEDULE B-4.

A. Schedule B-4 is a list of construction work in progress (CWIP) by major property grouping. Duke Energy Kentucky is not requesting to include its investment in CWIP in rate base.

EXHIBIT ____ (LK-7)

Duke Energy Kentucky
Case No. 2018-00261
Staff Second Set Data Requests
Date Received: October 10, 2018

STAFF-DR-02-006

REQUEST:

Refer to the Application, Volume 12.1, Section B, Schedule B-1.

a. Explain the reason(s) that Duke Kentucky is not requesting to include recovery of construction work in progress (CWIP) in base rates per footnote (2) on Schedule B-1.

b. Explain how Duke Kentucky obtains recovery on CWIP. Provide any authority for the Company's method of recovery on CWIP.

c. Provide the thirteen-month average of CWIP for the base period and forecasted test period and the amount of recovery Duke Kentucky is expected to receive on the CWIP investment for each period.

RESPONSE:

a. Similar to its most recently approved electric rate case, Case No. 2017-00321, Duke Energy Kentucky is not requesting to include recovery of CWIP in base rates because of past Commission precedent that effectively eliminates recovery of a return on CWIP. When CWIP is included in rate base, the Commission has, in past cases, included an AFUDC offset to operating income, which was calculated by multiplying the CWIP balance times the full weighted average cost of capital. The inclusion of the AFUDC offset effectively eliminates any revenue requirement in the test year related to CWIP.

b. See response to item a. The Company does not recover any return on CWIP in base rates.

c. Please see STAFF-DR-01-017(d) Attachment for a revised Schedule B-4 which provides CWIP as of November 30, 2018, for the base period and the thirteen-month average as of March 31, 2020, for the forecasted period.

PERSON RESPONSIBLE: Sarah E. Lawler

EXHIBIT ____ (LK-8)

Columbia Exhibit No. ______.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:	)	
	)	
APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF RATES	)))	Case No. 2016-00162

PREPARED DIRECT TESTIMONY OF
S. MARK KATKO
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 27, 2016

A: Since Columbia is filing a forecast test period rate case, a thirteen month average calculation was used to comply with Filing Requirement 6-c.

Q: Please describe in detail the individual supporting schedules for Schedule B.

A: Schedule B-2 shows Columbia's plant-in-service investment by major property grouping for the base period and the forecasted test period. Schedules B-2.1 through B-2.7 provide detail of the major property groupings by gas plant account and show the plant additions and retirements for each account during the base period and forecasted test period.

Schedule B-3 shows the accumulated depreciation and amortization balances by gas plant account for the base period and the forecasted test period.

Workpaper WPB-2.1 provides the monthly balances of plant-in-service by gas plant account for the base period and forecasted test period. Workpaper WPB-3.1 provides the monthly balances of accumulated depreciation and amortization by gas plant account for the base period and forecasted test period.

Schedule B-4 shows the amount of construction work-in-progress ("CWIP") as of February 29, 2016. Columbia has identified $731,955 of the total CWIP balance that was in-service as of February 29, 2016, but not yet classified to Account 106 or Account 101 as of that date. Therefore, this amount is included for recovery in rate base.

Q: How was the forecasted test period plant-in-service developed?

A: Calculations showing the development of the forecasted monthly plant-in-service balances are found in WPB-2.2. Actual per books plant-in-service as of February 29, 2016 in Accounts 101, 106, and the in-service portion of Account 107 is the starting point for the forecast. Budgeted plant additions were then added by month and budgeted retirements were deducted by month through the forecasted test period. Monthly budgeted capital additions were based on Columbia's capital budget discussed in the testimony of Columbia witness Belle and further adjusted for updated assumptions regarding the capital initiatives discussed previously in my testimony. Projected plant retirements were based on a three year average level of actual retirements recorded in 2013 through 2015. Projected plant additions and retirements were then increased by 5.3 percent to reflect Columbia's ten year history of exceeding its original capital expenditure forecasts. Columbia witness Belle describes Columbia's ten year budget experience.

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2016 - 00162
ACCOUNT 107 CONSTRUCTION WORK IN PROGRESS IN SERVICE
AS OF FEBRUARY 29, 2016

Data:__X___Base Period___X___Forecasted Period
Type of Filing:___X____Original________Updated
Workpaper Reference No(s). WPB-4

SCHEDULE B-4
SHEET 1 OF 1
WITNESS: S. M. KATKO

LINE NO. (A)	GPA (B)	DESCRIPTION (C)	TOTAL CWIP AMOUNT (D)	ACCUMULATED COSTS CONSTRUCTION AMOUNT (E)	CWIP AMOUNT IN SERVICE (F=D-E)	JURISDICTIONAL (G)	TOTAL COST (H=F*G)
			$	$	$	%	$
1	303.00	MISC INTANGIBLE PLANT	21,987	21,987	0	100.00	0
2	303.30	MISC INTANGIBLE PLANT	707,153	707,153	0		0
3		SUBTOTAL	729,140	729,140	0		0
4	374.40	LAND RIGHTS - OTHER DIST	71,154	71,154	0		0
5	375.40	REGULATING STRUCTURES	90,409	90,409	0		0
6	375.70	OTHER STRUCTURES	42,869	42,869	0		0
7	375.71	OTHER STRUCTURES-LEASED	26,357	26,357	0		0
8	376.00	MAINS	5,256,891	4,524,168	732,723		732,723
9	378.20	M&R EQUIP-GENERAL-REG	279,184	279,952	(768)		(768)
10	380.00	SERVICES	93,161	93,161	0		0
11	381.00	METERS	(21,903)	(21,903)	0		0
12	382.00	METER INSTALLATIONS	(14,872)	(14,872)	0		0
13	383.00	HOUSE REGULATORS	8,213	8,213	0		0
14	385.00	IND M&R EQUIPMENT	116,522	116,522	0		0
15	387.45	OTHER EQ-TELEMETERING	357,362	357,362	0		0
16		SUBTOTAL	6,305,349	5,573,394	731,955		731,955
17	391.10	OFF FUR & EQ UNSPECIF	21,458	21,458	0		0
18	391.12	OFF FUR & EQ INFORM. SYS.	63,206	63,206	0		0
19	394.30	TOOLS & OTHER	7,365	7,365	0		0
20		SUBTOTAL	92,029	92,029	0		0
21	TOTAL		7,126,518	6,394,563	731,955		731,955

EXHIBIT ____ (LK-9)

ATO-CWC1 A

Atmos Energy Corporation-Kentucky
Cash Working Capital Lead/Lag Analysis
For Forecast Test Year Ended March 31, 2020

Line No.	Description		Test Year Expenses	Average Daily Expense (b) / 365 days		Revenue Lag		Expense Lag	Net Lag (d) - (e)	CWC Requirement (c) x (f)
	(a)		(b)	(c)		(d)		(e)	(f)	(g)
1	Gas Supply Expense									
2	Purchased Gas		78,382,354	214,746	*CWC2*	40.82	*CWC3*	39.48	1.34	287,760
3										
4	Operation and Maintenance Expense									
5	O&M, Labor		10,802,619	29,596	*CWC2*	40.82	*CWC4*	14.08	26.74	791,397
6	O&M, Non-Labor		16,422,362	44,993	*CWC2*	40.82	*CWC5*	28.33	12.49	561,963
7	Total O&M Expense		27,224,981							1,353,360
8										
9	Taxes Other Than Income									
10	Ad Valorem		5,910,122	16,192	*CWC2*	40.82	*CWC6*	305.64	(264.82)	(4,287,956)
11	Taxes Property and Other		99,099	272	*CWC2*	40.82	*CWC6*	60.37	(19.55)	(5,318)
12	Payroll Taxes		355,960	975	*CWC2*	40.82	*CWC6*	83.63	(42.81)	(41,735)
13	Franchise and other pass through		9,703,180	26,584	*CWC2*	40.82	*CWC6*	38.52	2.30	61,144
14	Public Service Commission		339,436	930	*N/A*	0.00	*CWC6*	0.00	0.00	0
15	DOT		137,062	376	*CWC2*	40.82	*CWC6*	59.00	(18.18)	(6,836)
16										
17	Allocated Taxes-Shared Services									
18	Ad Valorem	20%	93,633	257	*CWC2*	40.82	*CWC6*	213.50	(172.68)	(44,379)
19	Payroll Taxes	80%	375,720	1,029	*CWC2*	40.82	*CWC6*	83.63	(42.81)	(44,046)
20										
21	Allocated Taxes-Business Unit									
22	Ad Valorem		4,779	13	*CWC2*	40.82	*CWC6*	305.64	(264.82)	(3,443)
23	Payroll Taxes		196,026	537	*CWC2*	40.82	*CWC6*	83.63	(42.81)	(22,986)
24	Total Taxes Other Than Income		17,215,017							(4,395,554)
25										
26	Federal Income Tax		*5,973,696*							
27	Current Taxes		0	0	*CWC2*	40.82	*CWC7*	29.75	11.07	0
28	Deferred Taxes		5,973,696	16,366	*CWC2*	40.82	*CWC7*	0.00	40.82	668,060
29										
30	State Income Tax		381,300							
31	Current Taxes		0	0	*CWC2*	40.82	*CWC8*	29.75	11.07	0
32	Deferred Taxes		381,300	1,045	*CWC2*	40.82	*CWC8*	0.00	40.82	42,657
33										
34	Depreciation		22,541,774	61,758	*CWC2*	40.82		0	40.82	2,520,962
35										
36	Interest Expense - STD		772,788	2,117	*CWC2*	40.82	*(1)*	35.20	5.62	11,898
37										
38	Interest Expense - LTD		8,594,947	23,548	*CWC2*	40.82	*CWC9*	90.02	(49.20)	(1,158,645)
39										
40	Return on Equity		30,064,352	82,368	*CWC2*	40.82		0	40.82	3,362,262
41										
42	TOTAL		191,151,210							2,692,759
43										
44	(1) Please see relied file labeled "CWC1 STD Days Outstanding.pdf (Page 9)" for calculation of average days held									

EXHIBIT ____ (LK-10)

REQUEST:

Provide the Company's stated goals for its capital structure in terms of the percentage levels of short term debt, long term debt, and equity.

RESPONSE:

As stated on page 58 of the Company's most recent 10K, "We utilize short-term debt to provide cost-effective, short-term financing until it can be replaced with a balance of long-term debt and equity financing that achieves the Company's desired capital structure with an equity-to-capitalization ratio between 50% and 60%, inclusive of long-term and short-term debt."

Please also see "Liquidity and Capital Resources" (beginning at page 32) and Notes to Consolidated Financial Statements No. 5 Debt (beginning at page 58) of the Company's 10K for more discussion of the Company's use of liquidity and capital resources.

Respondent: Joe Christian

EXHIBIT ____ (LK-11)

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended September 30, 2018

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-10042

Atmos Energy Corporation

(Exact name of registrant as specified in its charter)

Texas and Virginia **75-1743247**
(State or other jurisdiction of incorporation or organization) *(IRS employer identification no.)*

Three Lincoln Centre, Suite 1800
5430 LBJ Freeway, Dallas, Texas **75240**
(Address of principal executive offices) *(Zip code)*

Registrant's telephone number, including area code:
(972) 934-9227

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common stock, No Par Value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

The aggregate market value of the common voting stock held by non-affiliates of the registrant as of the last business day of the registrant's most recently completed second fiscal quarter, March 31, 2018 , was $9,175,655,493 .

As of November 8, 2018 , the registrant had 111,352,649 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

5. Debt

Long-term debt

Long-term debt at September 30, 2018 and 2017 consisted of the following:

	2018	2017
	(In thousands)	
Unsecured 8.50% Senior Notes, due March 2019	$ 450,000	$ 450,000
Unsecured 3.00% Senior Notes, due 2027	500,000	500,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Unsecured 5.50% Senior Notes, due 2041	400,000	400,000
Unsecured 4.15% Senior Notes, due 2043	500,000	500,000
Unsecured 4.125% Senior Notes, due 2044	750,000	750,000
Medium term Series A notes, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
Floating-rate term loan, due September 2019 (1)	125,000	125,000
Total long-term debt	3,085,000	3,085,000
Less:		
Original issue (premium) / discount on unsecured senior notes and debentures	(4,439)	(4,384)
Debt issuance cost	20,774	22,339
Current maturities	575,000	—
	$ 2,493,665	$ 3,067,045

(1) Up to $200 million can be drawn under this term loan.

Maturities of long-term debt at September 30, 2018 were as follows (in thousands):

2019	$ 575,000
2020	—
2021	—
2022	—
2023	—
Thereafter	2,510,000
	$ 3,085,000

On October 4, 2018, we completed a public offering of $600 million of 4.30% senior notes due 2048. We received net proceeds from the offering, after the underwriting discount and estimated offering expenses, of approximately $591 million , that were used to repay working capital borrowings pursuant to our commercial paper program. The effective interest rate of these notes is 4.37% after giving effect to the offering costs.

On June 8, 2017, we completed a public offering of $500 million of 3.00% senior notes due 2027 and $250 million of 4.125% senior notes due 2044. The effective rate of these notes is 3.12% and 4.40% , after giving effect to the offering costs and the settlement of the associated forward starting interest rate swaps. The net proceeds, excluding the loss on the settlement of the interest rate swaps of $37 million , of approximately $753 million were used to repay our $250 million 6.35% senior unsecured notes at maturity on June 15, 2017 and for general corporate purposes, including the repayment of working capital borrowings pursuant to our commercial paper program.

We utilize short-term debt to provide cost-effective, short-term financing until it can be replaced with a balance of long-term debt and equity financing that achieves the Company's desired capital structure with an equity-to-capitalization ratio between 50% and 60% , inclusive of long-term and short-term debt. Our short-term borrowing requirements are affected primarily by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers' needs could significantly affect our borrowing requirements. Our short-term borrowings typically reach their highest levels in the winter months.

EXHIBIT ____ (LK-12)

REQUEST:

Refer to Schedule J-3 for the Forecast Period in the instant proceeding. Refer also to Schedule J-3 for the Forecast Period filed in Case No. 2017-00349. Finally, refer to the Direct Testimony of Mr. Christian at page 7 lines 13-18.

a. Refer further to the balance outstanding reflected as $513 million for the planned March 2019 refinance on Schedule J-3 for the Forecast Period in the instant proceeding. Confirm that the difference between the $513 million and the $450 million being refinanced represents the additional long-term hedge instruments being utilized to lock in the rate.

b. Refer further to the balance outstanding reflected as $513 million for the planned March 2019 refinance on Schedule J-3 for the Forecast Period in the instant proceeding. Provide the estimated terms of the debt to be issued, including any additional long-term hedge instruments that may be utilized to lock in the rate.

c. The interest rate applicable to the $513 million planned March 2019 refinance is reflected as 5.07% on Schedule J-3 for the Forecast Period in the instant proceeding. Provide copies of all analyses and workpapers showing the derivation of the estimated debt rate of 5.07%.

d. Refer further to line 9 in Schedule J-3 for the Forecast Period in the instant proceeding, which portrays the interest rate for the $200 million 3 YR Sr. Credit Facility of 3.06%. Also refer to line 10 in Schedule J-3 for the Forecast Period filed in Case No. 2017-00349, which portrays the interest rate for the $200 million 3 YR Sr. Credit Facility of 1.82%. Explain all reasons why the amount of the interest rate has increased so much between the two periods. If the interest rate is variable, provide the basis for the determination of the rate.

e. Refer further to line 12 in Schedule J-3 for the Forecast Period in the instant proceeding, which portrays the annual cost of amortization of debt expense and debt discount of $6,580,966. Also refer to line 13 in Schedule J-3 for the Forecast Period filed in Case No. 2017-00349, which portrays the annual cost of amortization of debt expense and debt discount of $4,955,311. Explain all reasons why the amount of the annual net amortization is projected to increase by $1,625,655, or nearly 33%, between the two portrayed periods, especially when the balances for the unamortized debt expense and debt discounts do not have large corresponding net increases. As part of the answer, provide a reconciliation of the annual amortization and unamortized amounts by debt issue between the two periods.

RESPONSE:

a. Confirm, the difference in the current amount outstanding ($450 mm) and the $513 mm is created by the hedge instruments used to lock in the rate of 3.782%.

b. Please see the file "Staff_1-64_Att1 - Christian WP - Hypothetical Refinance 03-2019.xlsx" provided in the Company's response to Staff DR No. 1-64 for the assumptions made in arriving at the 5.07% rate used in the refinance calculation.

c. Please see the file "Staff_1-64_Att1 - Christian WP - Hypothetical Refinance 03-2019.xlsx" provided in the Company's response to Staff DR No. 1-64 for all of the analysis and workpapers associated with the refinance calculation.

d. The referenced amount is a variable rate instrument. The calculation for the 3.06% is as follows:

Applicable Margin: 1 Month Libor (2.09350% as of 6/27/18) + Spread (0.9000%) = **3.00%**
Commitment Fee Rate: 0.1000%
Amount Outstanding as of 6/30/18: $125,000,000
Unused Amount as of 6/30/18: $75,000,000
(($125,000,000*3.00%)+($75,000,000*0.10%))/$125,000,000 = **3.06%**

Please see Attachment 1 Credit Agreement as of 9/22/16 and Attachment 2 Credit Agreement Amendment as of 9/7/17 (the amendment was made pursuant to the removal of Fitch ratings).

e. The increase in annual net amortization is a result of settling hedges associated with the June 2017 financing ($250 mm in incremental new long-term debt plus $500 million in debt refinanced). Case No. 2017-00349 used balances as of June 30, 2017, which had not had the costs booked to the ledger and included in the net amortization that was included in that case.

ATTACHMENTS:

ATTACHMENT 1 - Atmos Energy Corporation, AG_1-15_Att1 - BB&T - AEC Term Loan Agreement - (Execution Version 9-22-2016).pdf, 90 Pages.

ATTACHMENT 2 - Atmos Energy Corporation, AG_1-15_Att2 - BBT_Atmos - First Amendment to Term Loan Agreement (Executed).pdf, 9 Pages.

Respondent: Joe Christian

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2017-00349
$450 MM Refinance
Forecasted Test Period: Twelve Months Ended March 31, 2019

As of 09/13/2018

Workpaper Reference No(s).____________________ Witness: Christian

Line No.	Issue		Amount Outstanding	Interest Rate	Effective Annual Cost
	(A)		(B)	(C)	(D)
1	8.50% Sr Note due 3/15/2019		450,000,000	8.500%	
2	Make Whole Premium				
3	Underlying Treasury out (in) the money as of 09/07/2018		63,000,000		
4	Sr Note due 3/15/2049		513,000,000		
5	Refinance - Underlying Treasury Yield Component	[1]		3.782%	
6	Refinance - Credit Spread			1.000%	
7	Refinance - Optional Redemption Make Whole Premium	[2]		0.000%	
8	Fees	[3]		0.292%	
9					
10					26,031,660
11	Total			5.07%	$ 26,031,660
12					
13	[1] FR 16(7)(I) Attachment 1 [2016 10K page 39)				
14	[2] AG DR No. 1-40 Att 1 Page 31 of 95 - NA if refinanced just prior to maturity				
15	[3] Estimated Fees		1,500,000		

Phone Call with Dan on 09/11:
We (ATO) would have to borrow an additional $63mm to settle the swaps today.

EXHIBIT ____ (LK-13)

REQUEST:

Refer to the Vander Weide Testimony, page 46, Table 2.

a. Provide the model results without any flotation adjustments.

b. Provide the model results without any flotation and size premium adjustments.

c. Provide all supporting workpapers in Excel spreadsheet format with all rows and columns accessible and formulas unhidden.

RESPONSE:

a) Dr. Vander Weide has presented his 10.4 percent estimate of Atmos Energy Kentucky's cost of equity based on cost of equity model estimates that include a flotation cost allowance and a size premium adjustment, as discussed in his testimony. For the reasons stated in his testimony, Dr. Vander Weide believes that it is appropriate to include a flotation cost allowance in his cost of equity studies and to use a size premium adjustment in applying the CAPM. Nonetheless, to respond to this data request, Dr. Vander Weide provides the following information.

		Staff 2-54 (a)	Staff 2-54 (b)
Method	Model Result	Model Result No Flotation	Model Result No Flotation, no size premium
DCF-Natural Gas Utilities	9.2%	9.1%	9.1%
Ex Ante Risk Premium	10.9%	10.7%	10.7%
Ex Post Risk Premium	10.2%	10.1%	10.1%
CAPM - Historical	9.7%	9.6%	9.4%
CAPM - DCF-based	11.7%	11.6%	11.6%
Average	10.4%	10.2%	10.2%

b) Please see the response to subpart (b).

c) Please see Attachment 1.

ATTACHMENT:

ATTACHMENT 1 - Atmos Energy Corporation, Staff_2-54_Att1 - Model Results_wo flotation_size Support.xlsx

Respondent: Dr. James Vander Weide

KY - 2018-00281 – Staff 2-54 c

Method	Model Result	Staff 2-54 (a) Model Result No Flotation	Staff 2-54 (b) Model Result No Flotation, No Size Premium
DCF—Natural Gas Utilities	9.2%	9.1%	9.1%
Ex Ante Risk Premium	10.9%	10.7%	10.7%
Ex Post Risk Premium	10.2%	10.1%	10.1%
CAPM – Historical	9.7%	9.6%	9.4%
CAPM – DCF-based	11.7%	11.6%	11.6%
Average	10.4%	10.2%	10.2%
CAPM – Historical	8.9%	8.7%	8.7%
CAPM – Historical	10.3%	10.1%	10.1%
CAPM – Historical - Size Premium	10.1%	9.9%	
CAPM - DCF Based	10.8%	10.6%	10.6%
CAPM - DCF Based	12.7%	12.5%	12.5%

EXHIBIT ____ (LK-14)

REQUEST:

Refer to the Vander Weide Testimony, page 20, lines 18-22. Provide the results of the annual Discounted Cash Flow (DCF) model in a table like Exhibit JVW-1, Schedule 1 in an Excel spreadsheet with all rows and columns unhidden and all formulas accessible.

RESPONSE:

Please see Attachment 1. For the reasons described in Dr. Vander Weide's testimony, Dr. Vander Weide believes that the quarterly DCF model is most appropriate because the quarterly model correctly accounts for the time value of money associated with the quarterly dividend payments made by the proxy utilities. However, Dr. Vander Weide notes that applying the annual DCF model to Dr. Vander Weide's proxy group of natural gas utilities at this time produces an average DCF result that is only three basis points lower than the result obtained by applying the quarterly DCF model to the Vander Weide proxy group.

ATTACHMENT:

ATTACHMENT 1 - Atmos Energy Corporation, Staff_2-47_Att1 - DCF Model Results.xlsx, 1 Page.

Respondent: Dr. James Vander Weide

KY - 2018-00281 – Staff 2-47

	Company	Jul-18	Jul-18	Jun-18	Jun-18	######	######	DIV1	DIV2	DIV3	DIV4	d_1	d_2	d_3	Most Recent Quarterly Dividend (d_0)	Stock Price (P_0)	I/B/E/S Forecast of Future Earnings Growth	Market Cap $ (Mil)	Annual DCF Model Result	1+g	1+k	No. of I/B/E/S Estimates
1	Atmos Energy	92.99	89.21	91.13	84.35	90.78	84.53								0.485	88.832	6.7%	10,188	9.1%	1.07	1.09	2
2	Chesapeake Utilities	87.25	79.10	80.75	73.55	80.90	74.05								0.370	79.267	6.0%	1,383	8.1%	1.06	1.08	1
3	New Jersey Resources	47.60	44.65	45.20	40.28	45.13	40.95								0.273	43.967	6.4%	4,023	9.2%	1.06	1.09	3
4	NiSource Inc.	27.01	25.31	26.31	23.23	25.75	24.18								0.195	25.298	5.7%	9,486	9.1%	1.06	1.09	3
5	Northwest Nat. Gas	66.60	62.65	65.28	56.90	62.75	57.00								0.473	61.863	4.5%	1,848	7.9%	1.05	1.08	2
6	ONE Gas Inc.	77.71	73.75	76.11	69.20	76.24	70.08								0.460	73.848	5.5%	4,023	8.3%	1.06	1.08	2
7	South Jersey Inds.	35.44	33.02	34.11	29.67	33.66	30.40								0.280	32.717	12.0%	2,896	16.0%	1.12	1.16	1
8	Southwest Gas	80.67	74.78	78.81	72.45	76.60	70.34								0.520	75.607	4.0%	3,824	7.0%	1.04	1.07	1
9	Spire Inc.	74.60	70.45	71.70	64.95	73.20	69.15								0.563	70.675	3.5%	3,653	6.9%	1.03	1.07	3
10	UGI Corp.	54.09	51.95	52.49	48.17	51.48	47.56								0.260	50.957	7.9%	9,201	10.2%	1.08	1.10	2
11	Average																		9.2%			
12	Market-weighted Average																		9.3%			
13	Average, simple, market-weighted																		9.2%			

EXHIBIT ____ (LK-15)

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated November 13, 2018

Case No. 2018-00294

Question No. 39

Responding Witness: Daniel K. Arbough

Q-39. Refer to the McKenzie Testimony, page 63. Provide the most recent awarded ROEs as published by RRA.

A-39. See attached.

S&P Global
Market Intelligence

October 11, 2018
spglobal.com/marketintelligence

RRA Regulatory Focus
Major Rate Case Decisions – January – September 2018

The average ROE authorized electric utilities was 9.64% in rate cases decided in the first three quarters of 2018, somewhat below the 9.74% average for cases decided in calendar-2017. There were 37 electric ROE determinations in the first nine months of 2018 versus 53 in the full year 2017. This data includes several limited-issue rider cases. Excluding these cases from the data, the average authorized ROE was 9.59% in rate cases decided in the first nine months of 2018, somewhat below the 9.68% average for the full year 2017. The difference between the ROE averages including rider cases and those excluding the rider cases is largely driven by ROE premiums of up to 200 basis points approved by the Virginia State Corporation Commission in riders related to certain generation projects (see the Virginia Commission Profile).

The average ROE authorized gas utilities was 9.62% in cases decided during the first three quarters of 2018 versus 9.72% in full-year 2017. There were 26 gas cases that included an ROE determination in the first nine months of 2018, versus 24 in full-year 2017. RRA notes that the 2017 data includes an 11.88% ROE determination for an Alaska utility. Absent this "outlier," the 2017 gas ROE average is 9.63%.

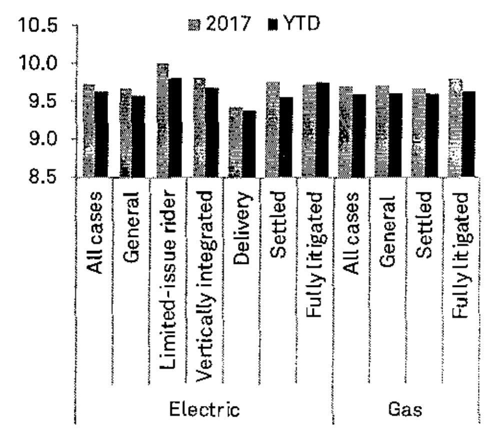
In the first nine months of 2018, the median authorized ROE in all electric utility rate cases was 9.7%, up from 9.6% from full-year 2017. For gas utilities, the median authorized ROE in cases decided in the first nine months of 2018 was 9.55%, versus 9.6% in 2017.

Over the last several years, the persistently low-interest-rate environment has put downward pressure on authorized ROEs. As shown in the graph below, the annual average ROE has generally declined since 1990 and has been below 10% for electric utilities since 2014 and below 10% for gas utilities since 2011.

After a busy 2017, when more than 130 cases were decided, there were 84 electric and gas cases in which a decision was rendered in the first three quarters of 2018, including cases where no ROEs were specified. With over 85 rate cases pending, 55 of which are likely to be decided by year end, 2018 is shaping up to be another busy year for regulators. Rate case activity has been quite robust, with more than 100 cases decided in several of the last full calendar years.

Authorized return on equity (%)

Dashboard



Electric	2017	YTD
All cases	9.74	9.64 ▼
General rate cases	9.68	9.59 ▼
Limited-issue rider cases	10.01	9.80 ▼
Vertically integrated cases	9.80	9.69 ▼
Delivery cases	9.43	9.38 ▼
Settled cases	9.75	9.55 ▼
Fully litigated cases	9.73	9.75 ▲
Gas	**2017**	**YTD**
All cases	9.72	9.62 ▼
General rate cases	9.72	9.62 ▼
Settled cases	9.68	9.61 ▼
Fully litigated cases	9.82	9.63 ▼

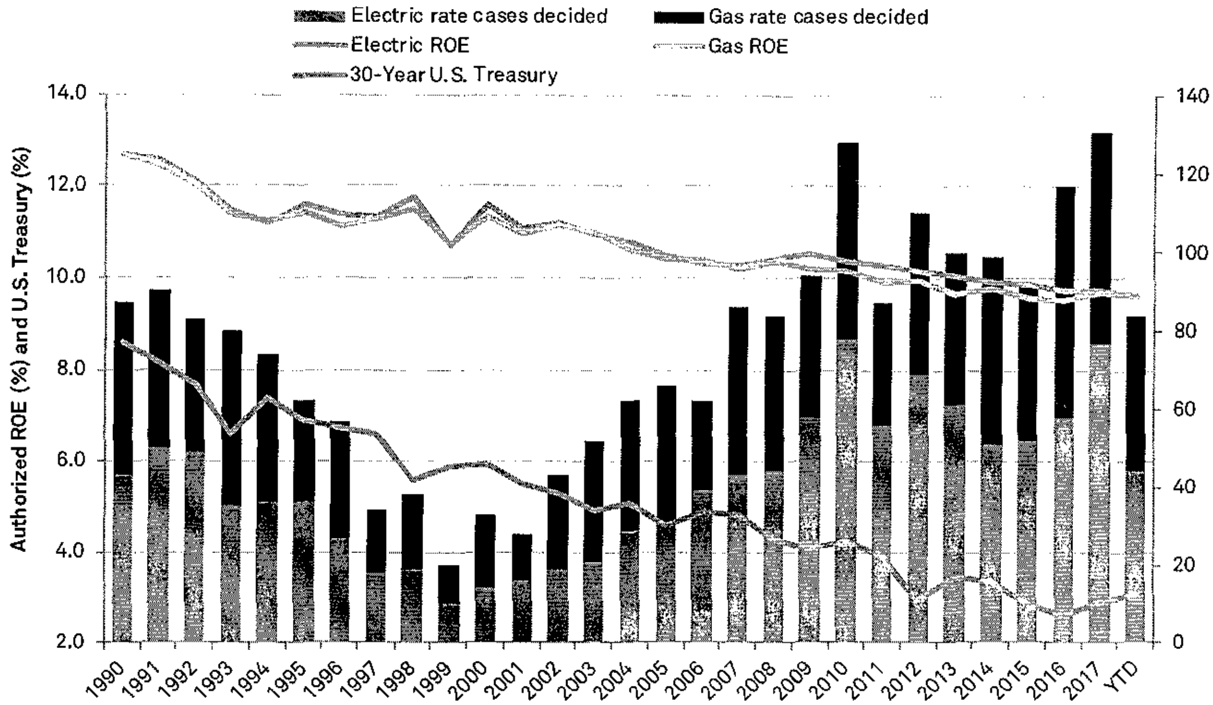
Data compiled Oct. 10, 2018.
YTD = year-to-date, through Sept. 30, 2018.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Lisa Fontanella
Principal Analyst

Sales & subscriptions
Sales_NorthAm@spglobal.com

Enquiries
support.mi@spglobal.com

Average electric and gas authorized ROEs and number of rate cases decided



Data compiled Oct. 10, 2018.
YTD = year-to-date, through Sept. 30, 2018.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Increased costs associated with environmental compliance, generation and delivery infrastructure upgrades and expansion, renewable generation mandates and employee benefits argue for the continuation of an active rate case agenda over the next few years. In addition, the need to address the impacts of the federal tax reform is causing rate case agendas to be more active than previously expected.

In addition, rising interest rates could also contribute to increased rate case activity. If the U.S. Federal Reserve, or the Fed, continues its policy initiated in 2015 to gradually raise the federal funds rate, utilities will likely face higher capital costs and need to initiate rate cases to reflect the higher capital costs in rates.

In September 2018, the Fed raised the benchmark federal funds rate by a quarter point, bringing the rate to a target range of 2.00% to 2.25%. The latest hike was the third increase in 2018 and the eighth since the Fed's tightening cycle began in 2015. One more hike is anticipated in December 2018, and as the U.S. economy continues to expand and labor markets remain strong, the Fed is expected to continue to gradually raise the federal fund rates in 2019.

A more granular look at ROE trends

The discussion thus far has looked broadly at trends in authorized ROEs; the sections that follow provide a more granular view based upon the types of proceedings/decisions in which these ROEs were established.

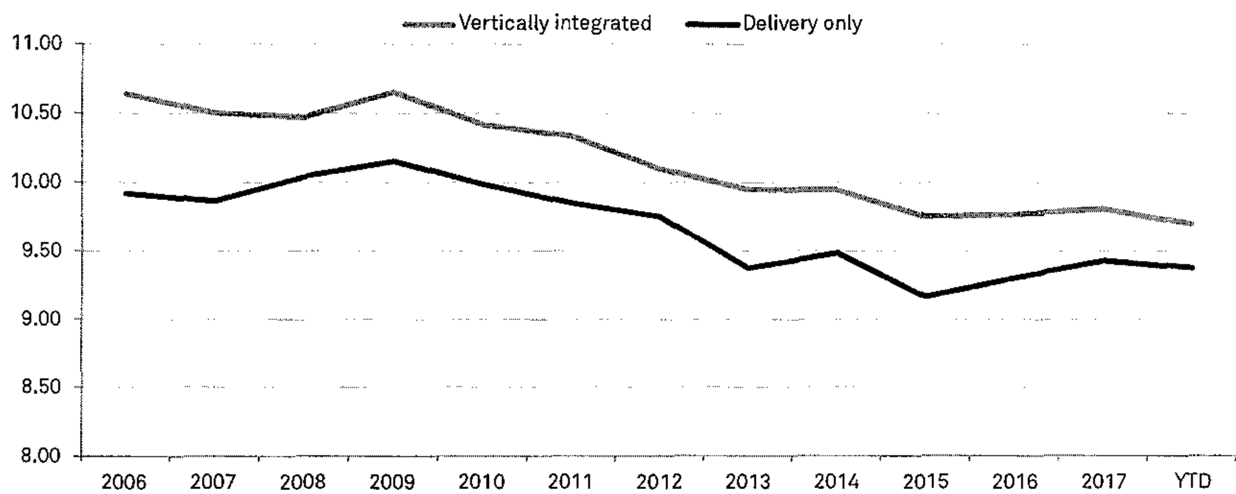
RRA has observed that there can be significant differences between the ROE averages from one subcategory of cases to another.

As a result of electric industry restructuring, certain states unbundled electric rates and implemented retail competition for generation. Commissions in those states now have jurisdiction only over the revenue requirement and return parameters for delivery operations.

Comparing electric vertically integrated cases versus delivery-only proceedings, RRA finds that the annual average authorized ROEs in vertically integrated cases typically are about 30 to 70 basis points higher than in delivery-only cases, arguably reflecting the increased risk associated with ownership and operation of generation assets.

For vertically integrated electric utilities, the average ROE authorized was 9.69% in cases decided during the first three quarters of 2018 versus 9.8% for cases decided in calendar-2017. For electric distribution-only utilities, the average ROE authorized in the first three quarters of 2018 was 9.38% versus 9.43% in all of 2017.

Average authorized electric ROEs



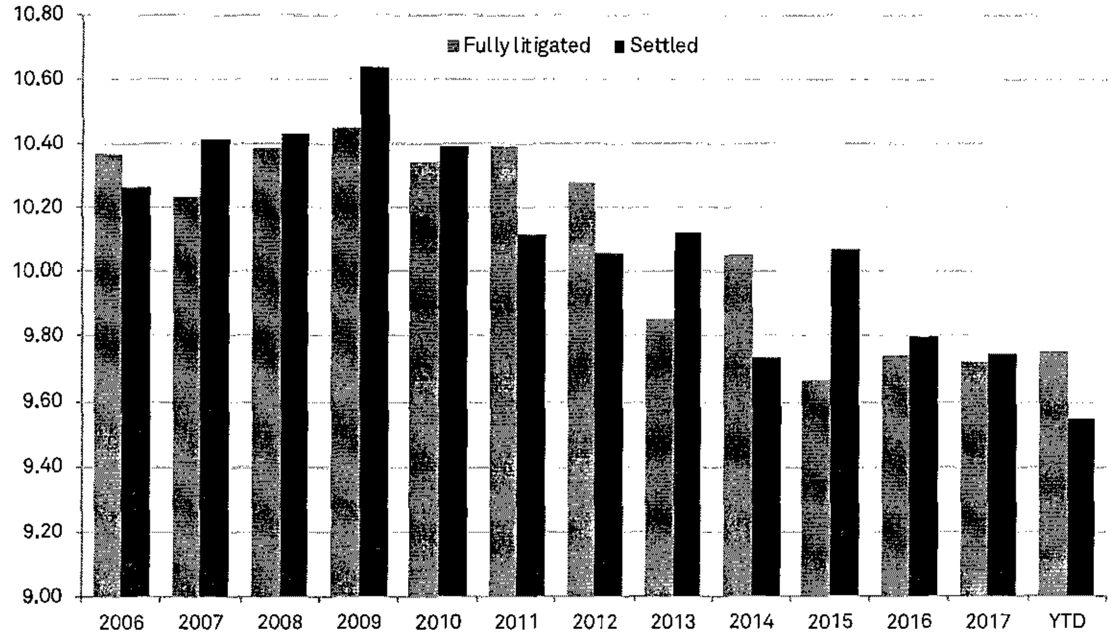
Data compiled Oct. 10, 2018.
YTD = year-to-date, through Sept. 30, 2018.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Settlements have frequently been used to resolve rate cases over the last several years, and in many cases, these settlements are "black box" in nature and do not specify the ROE and other typical rate case parameters underlying the stipulated rate change. However, some states preclude this type of treatment, and so, settlements must specify these values if not the specific adjustments from which these values were derived.

For both electric and gas cases, RRA has found no discernible pattern in the average authorized ROEs in cases that were settled versus those that were fully litigated. In some years, the average authorized ROE was higher for fully litigated cases, in others, it was higher for settled cases, and in a handful of years, the authorized ROE was similar for both fully litigated and settled cases.

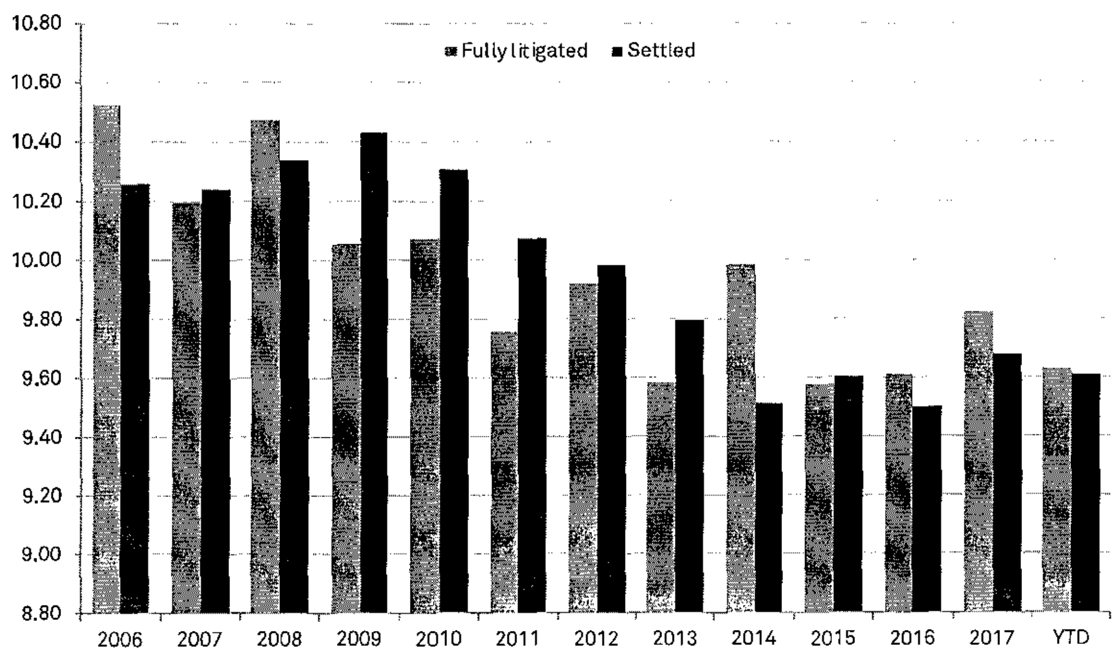
Over the last several years, the annual average authorized ROEs in electric cases that involve limited-issue riders was typically at least 70 basis points higher than in general rate cases, driven by the ROE premiums authorized in Virginia. Limited-issue rider cases in which an ROE is determined have had extremely limited use in the gas industry.

Average authorized electric ROEs, settled versus fully litigated cases



Data compiled Oct. 10, 2018.
YTD = year-to-date, through Sept. 30, 2018.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Average authorized gas ROEs, settled versus fully litigated cases



Data compiled Oct. 10, 2018.
YTD = year-to-date, through Sept. 30, 2018.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

The table on page 6 shows the average ROE authorized in major electric and gas rate decisions annually since 1990 and by quarter since 2014, followed by the number of observations in each period. The tables on page 7 indicate the composite electric and gas industry data for all major cases, summarized annually since 2004 and by quarter for the past six quarters.

Included in the tables beginning on page 8 of this report are comparisons, since 2006, of average authorized ROEs for settled versus fully litigated cases, general rate cases versus limited issue rider proceedings and vertically integrated cases versus delivery-only cases.

The individual electric and gas cases decided in 2018 are listed on pages 10 and 11, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return, or ROR, the ROE and the percentage of common equity in the adopted capital structure. Next, we indicate the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time decisions were rendered. Fuel adjustment clause rate changes are not reflected in this study.

The simple mean is utilized for the return averages. In addition, the average equity returns indicated in this report reflect the ROEs approved in cases that were decided during the specified time periods and are not necessarily representative of either the average currently authorized ROEs for utilities industrywide or the returns actually earned by the utilities.

Please note: In an effort to align data presented in this report with data available in S&P Global Market Intelligence's online database, earlier historical data provided in previous reports may not match historical data in this report due to certain differences in presentation, including the treatment of cases that were withdrawn or dismissed.

ROEs authorized January 1990 - September 2018

		Electric utilities			Gas utilities		
Year	Period	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
1990	Full year	12.70	12.77	38	12.68	12.75	33
1991	Full year	12.54	12.50	42	12.45	12.50	31
1992	Full year	12.09	12.00	45	12.02	12.00	28
1993	Full year	11.46	11.50	28	11.37	11.50	40
1994	Full year	11.21	11.13	28	11.24	11.27	24
1995	Full year	11.58	11.45	28	11.44	11.30	13
1996	Full year	11.40	11.25	18	11.12	11.25	17
1997	Full year	11.33	11.58	10	11.30	11.25	12
1998	Full year	11.77	12.00	10	11.51	11.40	10
1999	Full year	10.72	10.75	6	10.74	10.65	6
2000	Full year	11.58	11.50	9	11.34	11.16	13
2001	Full year	11.07	11.00	15	10.96	11.00	5
2002	Full year	11.21	11.28	14	11.17	11.00	19
2003	Full year	10.96	10.75	20	10.99	11.00	25
2004	Full year	10.81	10.70	21	10.63	10.50	22
2005	Full year	10.51	10.35	24	10.41	10.40	26
2006	Full year	10.32	10.23	26	10.40	10.50	15
2007	Full year	10.30	10.20	38	10.22	10.20	35
2008	Full year	10.41	10.30	37	10.39	10.45	32
2009	Full year	10.52	10.50	40	10.22	10.26	30
2010	Full year	10.37	10.30	61	10.15	10.10	39
2011	Full year	10.29	10.17	42	9.92	10.03	16
2012	Full year	10.17	10.08	58	9.94	10.00	35
2013	Full year	10.03	9.95	49	9.68	9.72	21
	1st quarter	10.23	9.86	8	9.54	9.60	6
	2nd quarter	9.83	9.70	5	9.84	9.95	8
	3rd quarter	9.87	9.78	12	9.45	9.33	6
	4th quarter	9.78	9.80	13	10.28	10.20	6
2014	Full year	9.91	9.78	38	9.78	9.78	26
	1st quarter	10.37	9.83	9	9.47	9.05	3
	2nd quarter	9.73	9.60	7	9.43	9.50	3
	3rd quarter	9.40	9.40	2	9.75	9.75	1
	4th quarter	9.62	9.55	12	9.68	9.75	9
2015	Full year	9.85	9.65	30	9.60	9.68	16
	1st quarter	10.29	10.50	9	9.48	9.50	6
	2nd quarter	9.60	9.60	7	9.42	9.52	6
	3rd quarter	9.76	9.80	8	9.47	9.50	4
	4th quarter	9.57	9.58	18	9.68	9.73	10
2016	Full year	9.77	9.75	42	9.54	9.50	26
	1st quarter	9.87	9.60	15	9.60	9.25	3
	2nd quarter	9.63	9.50	14	9.47	9.60	7
	3rd quarter	9.66	9.60	5	10.14	9.90	6
	4th quarter	9.73	9.60	19	9.68	9.55	8
2017	Full year	9.74	9.60	53	9.72	9.60	24
	1st quarter	9.75	9.90	13	9.68	9.80	6
	2nd quarter	9.54	9.50	13	9.43	9.50	7
	3rd quarter	9.63	9.70	11	9.69	9.60	13
2018	Year-to-date	9.64	9.70	37	9.62	9.55	26

Year-to-date, through Sept. 30, 2018.
Data compiled Oct. 10, 2018
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Electric and gas utilities — summary table

	Period	ROR (%)	Number of observations	ROE (%)	Number of observations	Common equity to total capital (%)	Number of observations	Rate change amount ($M)	Number of observations
Electric utilities									
2004	Full year	8.71	20	10.81	21	46.96	19	1,806.3	29
2005	Full year	8.44	23	10.51	24	47.34	23	936.1	31
2006	Full year	8.32	26	10.32	26	48.54	25	1,318.1	39
2007	Full year	8.18	37	10.30	38	47.88	36	1,405.7	43
2008	Full year	8.21	39	10.41	37	47.94	36	2,823.2	44
2009	Full year	8.24	40	10.52	40	48.57	39	4,191.7	58
2010	Full year	8.01	62	10.37	61	48.63	57	4,921.9	78
2011	Full year	8.00	43	10.29	42	48.26	42	2,595.1	56
2012	Full year	7.95	51	10.17	58	50.69	52	3,080.7	69
2013	Full year	7.66	45	10.03	49	49.25	43	3,328.6	61
2014	Full year	7.60	32	9.91	38	50.28	35	2,053.7	51
2015	Full year	7.38	35	9.85	30	49.54	30	1,891.5	52
2016	Full year	7.28	41	9.77	42	48.91	41	2,332.1	57
	1st quarter	6.97	15	9.87	15	47.95	15	1,028.3	24
	2nd quarter	7.11	9	9.63	14	48.77	9	597.0	19
	3rd quarter	7.43	5	9.66	5	49.63	5	558.6	10
	4th quarter	7.32	19	9.73	19	49.51	19	563.8	24
2017	Full year	7.18	48	9.74	53	48.90	48	2,747.7	77
	1st quarter	6.89	13	9.75	13	48.89	13	592.6	14
	2nd quarter	6.78	13	9.54	13	47.94	13	372.4	18
	3rd quarter	7.10	11	9.63	11	51.15	11	269.2	13
2018	Year-to-date	6.91	37	9.64	37	49.23	37	1,234.2	45
Gas utilities									
2004	Full year	8.51	23	10.63	22	45.81	22	306.0	33
2005	Full year	8.24	29	10.41	26	48.40	24	465.4	35
2006	Full year	8.44	17	10.40	15	47.24	16	392.5	23
2007	Full year	8.11	31	10.22	35	48.47	28	645.3	43
2008	Full year	8.49	33	10.39	32	50.35	32	700.0	40
2009	Full year	8.15	29	10.22	30	48.49	29	438.6	36
2010	Full year	7.99	40	10.15	39	48.70	40	776.5	50
2011	Full year	8.09	18	9.92	16	52.49	14	367.0	31
2012	Full year	7.98	30	9.94	35	51.13	32	264.0	41
2013	Full year	7.43	21	9.68	21	50.60	20	498.7	40
2014	Full year	7.65	27	9.78	26	51.11	28	544.2	48
2015	Full year	7.34	16	9.60	16	49.93	16	494.1	40
2016	Full year	7.08	28	9.54	26	50.06	26	1,263.8	59
	1st quarter	7.20	2	9.60	3	51.57	3	71.0	9
	2nd quarter	7.27	5	9.47	7	49.15	5	85.3	13
	3rd quarter	7.07	8	10.14	6	46.58	7	128.6	17
	4th quarter	7.43	9	9.68	8	52.30	9	125.8	15
2017	Full year	7.26	24	9.72	24	49.88	24	410.7	54
	1st quarter	7.14	5	9.68	6	51.05	6	198.0	9
	2nd quarter	7.08	7	9.43	7	50.83	6	73.8	11
	3rd quarter	6.86	15	9.69	13	48.55	15	272.8	20
2018	Year-to-date	6.97	27	9.62	26	49.61	27	544.6	40

Year-to-date, through Sept. 30, 2018.
Data compiled Oct. 10, 2018
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Electric authorized ROEs: 2006 - September 2018

Settled versus fully litigated cases

	All cases			Settled cases			Fully litigated cases		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2006	10.32	10.23	26	10.26	10.25	11	10.37	10.12	15
2007	10.30	10.20	38	10.42	10.33	14	10.23	10.15	24
2008	10.41	10.30	37	10.43	10.25	17	10.39	10.54	20
2009	10.52	10.50	40	10.64	10.62	16	10.45	10.50	24
2010	10.37	10.30	61	10.39	10.30	34	10.35	10.10	27
2011	10.29	10.17	42	10.12	10.07	16	10.39	10.25	26
2012	10.17	10.08	58	10.06	10.00	29	10.28	10.25	29
2013	10.03	9.95	49	10.12	9.98	32	9.85	9.75	17
2014	9.91	9.78	38	9.73	9.75	17	10.05	9.83	21
2015	9.85	9.65	30	10.07	9.72	14	9.66	9.62	16
2016	9.77	9.75	42	9.80	9.85	17	9.74	9.60	25
2017	9.74	9.60	53	9.75	9.60	29	9.73	9.56	24
2018 YTD	9.64	9.70	37	9.55	9.62	20	9.75	9.73	17

General rate cases versus limited-issue riders

	All cases			General rate cases			Limited issue riders		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2006	10.32	10.23	26	10.34	10.25	25	9.80	9.80	1
2007	10.30	10.20	38	10.32	10.23	36	9.90	9.90	1
2008	10.41	10.30	37	10.37	10.30	35	11.11	11.11	2
2009	10.52	10.50	40	10.52	10.50	38	10.55	10.55	2
2010	10.37	10.30	61	10.29	10.26	58	11.87	12.30	3
2011	10.29	10.17	42	10.19	10.14	40	12.30	12.30	2
2012	10.17	10.08	58	10.02	10.00	51	11.57	11.40	6
2013	10.03	9.95	49	9.82	9.82	40	11.34	11.40	7
2014	9.91	9.78	38	9.76	9.75	32	10.96	11.00	5
2015	9.85	9.65	30	9.60	9.53	23	10.87	11.00	6
2016	9.77	9.75	42	9.60	9.60	32	10.31	10.55	10
2017	9.74	9.60	53	9.68	9.60	42	10.01	9.95	10
2018 YTD	9.64	9.70	37	9.59	9.62	28	9.80	10.20	9

Vertically integrated cases versus delivery-only cases

	All cases			Vertically integrated cases			Delivery only cases		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2006	10.32	10.23	26	10.63	10.54	15	9.91	10.03	10
2007	10.30	10.20	38	10.50	10.45	26	9.86	9.98	10
2008	10.41	10.30	37	10.48	10.47	26	10.04	10.25	9
2009	10.52	10.50	40	10.66	10.66	28	10.15	10.30	10
2010	10.37	10.30	61	10.42	10.40	41	9.98	10.00	17
2011	10.29	10.17	42	10.33	10.20	28	9.85	10.00	12
2012	10.17	10.08	58	10.10	10.20	39	9.75	9.73	12
2013	10.03	9.95	49	9.95	10.00	31	9.37	9.36	9
2014	9.91	9.78	38	9.94	9.90	19	9.49	9.55	13
2015	9.85	9.65	30	9.75	9.70	17	9.17	9.07	6
2016	9.77	9.75	42	9.77	9.78	20	9.31	9.33	12
2017	9.74	9.60	53	9.80	9.65	28	9.43	9.55	14
2018 YTD	9.64	9.70	37	9.69	9.77	19	9.38	9.35	9

YTD = year-to-date, through Sept. 30, 2018.
Data compiled Oct. 10, 2018
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Gas average authorized ROEs: 2006 - September 2018

Settled versus fully litigated cases

	All cases			Settled cases			Fully litigated cases		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2006	10.40	10.50	15	10.26	10.20	7	10.53	10.80	8
2007	10.22	10.20	35	10.24	10.18	22	10.20	10.40	13
2008	10.39	10.45	32	10.34	10.28	20	10.47	10.68	12
2009	10.22	10.26	30	10.43	10.40	13	10.05	10.15	17
2010	10.15	10.10	39	10.30	10.15	12	10.08	10.10	27
2011	9.92	10.03	16	10.08	10.08	8	9.76	9.80	8
2012	9.94	10.00	35	9.99	10.00	14	9.92	9.90	21
2013	9.68	9.72	21	9.80	9.80	9	9.59	9.60	12
2014	9.78	9.78	26	9.51	9.50	11	9.98	10.10	15
2015	9.60	9.68	16	9.60	9.60	11	9.58	9.80	5
2016	9.54	9.50	26	9.50	9.50	16	9.61	9.58	10
2017	9.72	9.60	24	9.68	9.60	17	9.82	9.50	7
2018 YTD	9.62	9.55	26	9.61	9.60	15	9.63	9.50	11

General rate cases versus limited issue riders

	All cases			General rate cases			Limited issue riders		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2006	10.40	10.50	15	10.40	10.50	15	—	—	0
2007	10.22	10.20	35	10.22	10.20	35	—	—	0
2008	10.39	10.45	32	10.39	10.45	32	—	—	0
2009	10.22	10.26	30	10.22	10.26	30	—	—	0
2010	10.15	10.10	39	10.15	10.10	39	—	—	0
2011	9.92	10.03	16	9.91	10.05	15	10.00	10.00	1
2012	9.94	10.00	35	9.93	10.00	34	10.40	10.40	1
2013	9.68	9.72	21	9.68	9.72	21	—	—	0
2014	9.78	9.78	26	9.78	9.78	26	—	—	0
2015	9.60	9.68	16	9.60	9.68	16	—	—	0
2016	9.54	9.50	26	9.53	9.50	25	9.70	9.70	1
2017	9.72	9.60	24	9.72	9.60	24	—	—	0
2018 YTD	9.62	9.55	26	9.62	9.60	25	9.50	9.50	1

YTD = year-to-date, through Sept. 30, 2018.
Data compiled Oct. 10, 2018.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

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RRA Regulatory Focus: Major Rate Case Decisions

Electric utility decisions

Date	Company	State	ROR (%)	ROE (%)	Common equity as % of capital	Test year	Rate base	Rate change amount ($)	Footnotes
1/18/18	Kentucky Power Company	KY	6.44	9.70	41.68	2/17	Year-end	12.3	B
1/31/18	Public Service Company of Oklahoma	OK	6.88	9.30	48.51	12/16	Year-end	75.5	R
2/2/18	Interstate Power and Light Company	IA	7.49	9.98	49.02	12/16	Average	130.0	B, I
2/6/18	Mississippi Power Company	MS	6.62	8.58	50.45	12/18	Average	—	B, LIR, 1
2/9/18	Delmarva Power & Light Company	MD	—	—	—	9/17	—	13.4	B, D
2/9/18	Virginia Electric and Power Company	VA	7.21	10.20	50.23	3/19	Average	-6.0	LIR,2
2/14/18	Virginia Electric and Power Company	VA	7.21	10.20	50.23	3/19	Average	-11.5	LIR,3
2/20/18	Virginia Electric and Power Company	VA	7.21	10.20	50.23	3/19	Average	-24.6	LIR,4
2/21/18	Virginia Electric and Power Company	VA	6.71	9.20	50.23	3/19	Average	0.2	LIR,5
2/23/18	Duke Energy Progress, LLC	NC	7.09	9.90	52.00	12/16	Year-end	194.0	B
2/27/18	Virginia Electric and Power Company	VA	7.20	11.20	50.23	3/19	Average	14.9	LIR,6
3/12/18	ALLETE (Minnesota Power)	MN	7.06	9.25	53.81	12/17	Average	12.0	I
3/15/18	Niagara Mohawk Power Corporation	NY	6.53	9.00	48.00	3/19	Average	160.0	B, D, Z
3/20/18	Georgia Power Company	GA	—	—	—	12/18	—	-50.0	LIR,7
3/29/18	Consumers Energy Company	MI	5.89	10.00	40.89	9/18	Average	72.3	I,R,*
2018	**1st quarter: averages/total**		**6.89**	**9.75**	**48.89**			**592.6**	
	Observations		**13**	**13**	**13**			**14**	
4/2/18	Appalachian Power Company	VA	—	—	—	—	—	—	LIR,8
4/12/18	Indiana Michigan Power Company	MI	5.76	9.90	36.38	12/18	Average	49.1	*
4/13/18	Duke Energy Kentucky, Inc.	KY	6.83	9.73	49.25	3/19	Average	8.4	
4/18/18	Connecticut Light and Power Company	CT	7.09	9.25	53.00	12/16	Average	124.7	B, D, Z
4/18/18	DTE Electric Company	MI	5.34	10.00	36.84	10/18	Average	74.4	I, R, *
4/26/18	Public Service Company of Colorado	CO	—	—	—	—	—	—	9
4/26/18	Avista Corporation	WA	7.50	9.50	48.50	12/16	Average	10.8	
5/8/18	Kentucky Utilities Company	VA	—	—	—	12/16	—	1.8	B
5/10/18	Virginia Electric and Power Company	VA	6.71	9.20	50.23	6/18	—	2.8	LIR,10
5/16/18	Appalachian Power Company	VA	—	—	—	6/19	—	1.0	LIR,11
5/23/18	Southern Indiana Gas and Electric Company, Inc.	IN	—	—	—	10/17	Year-end	1.9	LIR
5/30/18	Indiana Michigan Power Company	IN	5.51	9.95	35.73	12/18	Year-end	153.4	B,Z
5/30/18	Northern Indiana Public Service Company	IN	—	—	—	11/17	Year-end	12.6	LIR
5/31/18	Potomac Electric Power Company	MD	7.03	9.50	50.44	12/17	—	-15.0	B, D
6/14/18	Central Hudson Gas & Electric Corporation	NY	6.44	8.80	48.00	6/19	Average	19.7	B, D, Z
6/19/18	Oklahoma Gas and Electric Company	OK	—	—	—	9/17	—	-64.0	B,12
6/22/18	Hawaiian Electric Company, Inc.	HI	7.57	9.50	57.10	12/17	Average	-0.6	B, I
6/22/18	Duke Energy Carolinas, LLC	NC	7.35	9.90	52.00	12/16	Year-end	-13.0	B,R
6/28/18	Emera Maine	ME	7.18	9.35	49.00	12/16	Average	4.5	D
6/29/18	Hawaii Electric Light Company, Inc.	HI	7.80	9.50	56.69	12/16	Average	-0.1	B, I
	2nd quarter: averages/total		**6.78**	**9.54**	**47.94**			**372.4**	
	Observations		**13**	**13**	**13**			**18**	
7/3/18	Virginia Electric and Power Company	VA	6.71	9.20	50.23	8/19	Average	3.3	LIR,13
7/3/18	Virginia Electric and Power Company	VA	7.21	10.20	50.23	8/19	Average	-11.1	LIR,14
7/10/18	Duke Energy Florida, LLC	FL	—	—	—	—	—	200.5	B, LIR, Z, 15
7/25/18	Atlantic City Electric Company	NJ	—	—	—	12/18	—	—	D,16
8/8/18	Potomac Electric Power Company	DC	7.45	9.53	50.44	12/17	—	-24.1	B, D
8/21/18	Delmarva Power & Light Company	DE	6.78	9.70	50.52	12/17	—	-6.9	B, D, I
8/24/18	Narragansett Electric Company	RI	6.97	9.28	50.95	6/17	Average	28.9	B, D, Z,
8/31/18	Appalachian Power Company	WV	—	—	—	12/17	—	91.6	B, LIR, 17
9/5/18	Southwestern Public Service Company	NM	6.85	9.10	51.00	6/18	Year-end	8.1	
9/14/18	Wisconsin Power and Light Company	WI	7.09	10.00	52.00	12/20	Average	0.0	B,18
9/20/18	Madison Gas and Electric Company	WI	7.10	9.80	56.06	12/20	Average	-8.0	B
9/26/18	Otter Tail Power Company	ND	7.64	9.77	52.50	12/18	Average	7.4	B, I
9/26/18	Dayton Power and Light Company	OH	7.27	10.00	47.52	5/16	Date Certain	29.8	B, D
9/27/18	Westar Energy, Inc.	KS	7.06	9.30	51.24	6/17	Year-end	-50.3	B
2018	**3rd quarter: averages/total**		**7.10**	**9.63**	**51.15**			**269.2**	
	Observations		**11**	**11**	**11**			**13**	
2018	**YTD: averages/total**		**6.91**	**9.64**	**49.23**			**1,234.2**	
	Observations		**37**	**37**	**37**			**45**	

YTD = year-to-date, through Sept. 30, 2018.
Data compiled Oct. 10, 2018.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

S&P Global
Market Intelligence

RRA Regulatory Focus: Major Rate Case Decisions

Gas utility decisions

Date	Company	State	ROR (%)	ROE (%)	Common equity as % of capital	Test year	Rate base	Rate change amount ($)	Footnotes
1/24/18	Indiana Gas Company, Inc.	IN	—	—	—	6/17	Year-end	8.4	LIR,19
1/24/18	Southern Indiana Gas and Electric Company, Inc.	IN	—	—	—	6/17	Year-end	1.3	LIR,19
1/31/18	Northern Illinois Gas Company	IL	7.26	9.80	52.00	12/18	Average	93.5	R
2/21/18	Missouri Gas Energy	MO	7.20	9.80	54.16	12/16	Year-end	15.2	
2/21/18	Spire Missouri Inc.	MO	7.20	9.80	54.16	12/16	Year-end	18.0	
2/27/18	Atmos Energy Corporation	KS	—	—	—	9/17	—	0.8	LIR,20
2/28/18	Northern Utilities, Inc.	ME	7.53	9.50	50.00	12/16	Average	-0.1	
3/15/18	Niagara Mohawk Power Corporation	NY	6.53	9.00	48.00	3/19	Average	45.5	B, Z
3/26/18	Pivotal Utility Holdings, Inc.	FL	—	10.19	48.00	12/18	—	15.3	B, Z, I
2018	**1st quarter: averages/total**		**7.14**	**9.68**	**51.05**			**198.0**	
	Observations		**5**	**6**	**6**			**9**	
4/26/18	Avista Corporation	WA	7.50	9.50	48.50	12/16	Average	-2.1	
4/27/18	Liberty Utilities (EnergyNorth Natural Gas) Corp.	NH	6.80	9.30	49.21	12/16	Year-end	8.1	Z, I
5/2/18	Northern Utilities, Inc.	NH	7.59	9.50	51.70	12/16	Year-end	0.9	B, Z, I
5/3/18	Atmos Energy Corporation	KY	7.41	9.70	52.57	3/19	Average	-1.9	
5/10/18	CenterPoint Energy Resources Corp.	MN	7.12	—	—	9/18	Average	3.9	B, I
5/15/18	Atlanta Gas Light Company	GA	—	—	55.00	12/18	—	-16.0	B
5/29/18	MDU Resources Group, Inc.	MT	—	9.40	—	—	—	1.0	B
5/30/18	Baltimore Gas and Electric Company	MD	6.69	—	—	12/23	—	68.0	LIR, Z,21
6/6/18	Liberty Utilities (Midstates Natural Gas) Corp	MO	—	9.80	—	6/17	Year-end	4.6	B
6/14/18	Central Hudson Gas & Electric Corporation	NY	6.44	8.80	48.00	6/19	Average	6.7	B, Z
6/19/18	Black Hills Kansas Gas Utility Company, LLC	KS	—	—	—	2/18	Year-end	0.6	LIR
	2nd quarter: averages/total		**7.08**	**9.43**	**50.83**			**73.8**	
	Observations		**7**	**7**	**6**			**11**	
7/16/18	Black Hills Northwest Wyoming Gas Utility Company, LLC	WY	7.75	9.60	54.00	6/17	Year-end	1.0	B
7/20/18	Cascade Natural Gas Corporation	WA	7.31	9.40	49.00	12/16	Average	-2.9	B
8/15/18	Virginia Natural Gas, Inc.	VA	6.86	9.50	48.74	8/19	Average	3.2	LIR,22
8/21/18	Delta Natural Gas Company, Inc.	KY	—	—	—	12/17	Year-end	2.2	LIR,23
8/22/18	Northern Indiana Public Service Company	IN	—	—	—	12/17	Year-end	14.2	LIR,24
8/24/18	Narragansett Electric Company	RI	7.15	9.28	50.95	6/17	Average	17.4	B, Z
8/28/18	Consumers Energy Company	MI	5.86	10.00	40.91	6/19	Average	10.6	B,*
9/5/18	Indiana Gas Company, Inc.	IN	—	—	—	12/17	Year-end	9.8	LIR,25
9/5/18	Southern Indiana Gas and Electric Company, Inc.	IN	—	—	—	12/17	Year-end	2.2	LIR,26
9/11/18	CenterPoint Energy Resources Corp.	AR	4.69	—	31.52	9/19	Year-end	5.1	B,*
9/13/18	DTE Gas Company	MI	5.56	10.00	38.30	9/19	Average	9.0	*
9/14/18	Wisconsin Power and Light Company	WI	6.97	10.00	52.00	12/18	Average	0.0	B,27
9/19/18	Northern Indiana Public Service Company	IN	6.50	9.85	46.88	12/18	Year-end	107.3	B, Z
9/19/18	Bay State Gas Company	MA	—	—	—	—	—	—	28
9/20/18	Madison Gas and Electric Company	WI	7.10	9.80	56.06	12/20	Average	4.1	B,Z
9/26/18	MDU Resources Group, Inc.	ND	7.24	9.40	51.00	12/18	Average	2.5	B, I
9/26/18	Piedmont Natural Gas Company, Inc.	SC	7.60	10.20	53.00	3/18	Year-end	-13.9	B,M
9/26/18	South Carolina Electric & Gas Co.	SC	8.05	—	49.83	3/18	Year-end	-19.7	M
9/28/18	Boston Gas Company	MA	7.01	9.50	53.04	12/16	Year-end	100.8	
9/28/18	Colonial Gas Company	MA	7.18	9.50	53.04	12/16	Year-end	17.8	
9/28/18	Columbia Gas of Maryland, Incorporated	MD	—	—	—	12/19	Average	2.0	B, LIR,29
2018	**3rd quarter: averages/total**		**6.86**	**9.69**	**48.55**			**272.8**	
	Observations		**15**	**13**	**15**			**20**	
2018	**YTD: averages/total**		**6.97**	**9.62**	**49.61**			**544.6**	
	Observations		**27**	**26**	**27**			**40**	

YTD = year-to-date, through Sept. 30, 2018.
Data compiled Oct. 10, 2018.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Footnotes

A Average.

B Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.

CWIP Construction work in progress.

D Applies to electric delivery only.

DCt Date-certain rate base valuation.

E Estimated.

F Return on fair value rate base.

Hy Hypothetical capital structure utilized.

I Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.

LIR Limited-issue rider proceeding.

M "Make-whole" rate change based on return on equity or overall return authorized in previous case.

R Revised.

Te Temporary rates implemented prior to the issuance of final order.

Tr Applies to transmission service.

U Double leverage capital structure utilized.

YE Year-end.

Z Rate change implemented in multiple steps.

* Capital structure includes cost-free items or tax credit balances at the overall rate of return.

1 Decision adopted a company filing specifying a $99.3 million plant-specific retail revenue requirement. According to the company, this results in an annual rate reduction of approximately $26.8 million.

2 Rate change was approved under Rider R, which is the mechanism through which the company recovers its investment in the Bear Garden power plant.

3 Rate change was approved under Rider W, which is the mechanism through which the company recovers its investment in the Warren County generation facility.

4 Rate change was approved under Rider S, which is the mechanism through which the company recovers its investment in the Virginia City Hybrid Energy Center.

5 Rate change was approved under Rider GV, which is the mechanism through which the company recovers its investment in the Greensville County generation facility.

6 Rate change was approved under Rider B, which is the mechanism through which the company recovers the costs associated with the conversion of the Altavista, Hopewell and Southampton Power Stations to burn biomass fuels.

7 Reduction ordered to the nuclear construction cost recovery tariff associated with the company's two new units being built at its Vogtle plant.

8 Proposed acquisition of the Beech Ridge II and Hardin wind generation facilities, and an associated rider was rejected. No initial revenue requirement had been proposed.

9 Rate case dismissed.

10 Rate change was approved under Rider DSM, which is the mechanism through which the company is permitted to collect a cash return on demand-side management program costs.

11 Rate change was approved under Rider RAC-EE, which is the mechanism through which the company recovers its investment in energy efficiency programs.

12 ROE to be used for certain riders and AFUDC purposes is 9.5%.

13 Rate change was approved under Rider US-2, which is the mechanism through which the company recovers its investment in three utility-scale solar facilities: Scott Solar, Whitehouse Solar and Woodland Solar.

14 Rate change was approved under Rider BW, which is the mechanism through which the company recovers its investment in the Brunswick Power Station.

15 Rate change pertains to the company's Citrus County CC natural gas plant that is nearing completion.

16 Case was dismissed without prejudice.

17 Rate change was approved under the company's joint expanded net energy cost proceeding.

18 Decision freezes electric rates at 2017 levels for 2018 and 2019.

19 Case established the rates to be charged to customers under the company's compliance and system improvement adjustment, or CSIA, mechanism, which includes both federally mandated pipeline-safety initiatives and projects that are permitted under the state's transmission, distribution and storage system improvement charge, or TDSIC, statute.

20 Reflects updates to the company's gas system reliability surcharge rider since its most recent base rate case.

21 Rate change was approved under the company's Strategic Infrastructure Development and Enhancement, or STRIDE, rider.

22 Case involves the company's investment made under Virginia Steps to Advance Virginia Energy infrastructure program.

23 Case involves the company's pipe replacement program rider.

24 Case involves company's TDSIC rate adjustment mechanism.

25 Case involves the company's CSIA mechanism and projects that are permitted under the state's TDSIC statute.

26 Pertains to investments made under the company's CSIA mechanism and projects that are permitted under the state's TDSIC statute.

27 Freezes gas rates at 2017 levels for 2018 and 2019.

28 Rate case withdrawn.

29 Case relates to the company's investment in its STRIDE program.

30 Rate change was approved under the company's infrastructure replacement and improvement surcharge, or IRIS, rider through which the company recovers costs associated with its STRIDE plan.

EXHIBIT ____ (LK-16)

REQUEST:

Refer to Atmos's response to the Attorney General's Initial Request, Item 8.

a. Confirm that it is Atmos's intent to limit former-PAP expenditures to $28 million per year. If confirmed, explain why "PRP Investment" amounts of $28.8 million are listed for fiscal years 2019 and 2020.

b. Explain in detail and include a listing of major projects, the 70 percent increase in "Non PRP Investment" between fiscal years 2018 and 2019.

RESPONSE:

a. Confirmed. The $28.8 million figures in 2019 and 2020 were erroneous. The corrected table follows:

$ millions

Fiscal Year	PRP Investment	Non PRP Investment	Total Direct Investment	PRP as % of Total
2013	$ 17.2	$ 18.3	$ 35.5	48%
2014	22.7	26.6	49.3	46%
2015	36.9	18.6	55.5	66%
2016	30.0	34.2	64.2	47%
2017	39.9	33.0	72.9	55%
2018	45.9	33.9	79.8	58%
2019	28.0	58.7	86.7	32%
2020	28.0	68.7	96.7	29%

Please see Attachment 1 to the Company's response to Staff DR No. 3-27 for project level detail by month for the Company's fiscal 2019 budget. The Attachment lists PRP projects for FY19 that total $28.8 million. While this is $0.8 million higher than the $28 million ordered by the Commission in Case No. 2017-00349, it is and will continue to be the Company's intention to comply with the Commission's Order. The $0.8 million discrepancy represents 2.9% of the intended PRP target and is due to the systematic allocation of the overhead pool across projects in the Company's budgeting system.

b. Please see Attachment 1. The primary drivers of the increase in non PRP investment between 2018 and 2019 are the ANR Bon Harbor, Paducah Mall & Creek HCA, and KY Farm Tap projects.

ANR Bon Harbor - Project includes the installation of approximately 4 miles of 8 inch from ANR/TransCanada purchase in Stanley, KY to Atmos Energy's Bon Harbor storage field. Gas conditioning equipment at the storage field is being upgraded for well injection/withdraw and will eliminate on-site compression. With successful completion of the project, the existing 4 inch pipeline running from Stanley to Bon Harbor will be downgraded from Transmission to High Pressure Distribution, eliminating a High Consequence Area (HCA) in Owensboro and reducing risk.

Paducah Mall & Creek HCA - Project involves the replacement of approximately 15,000 feet of 8 inch steel transmission pipe eliminating one High Consequence Area (HCA). The installation of the new pipe allows the operation of existing pipe at distribution pressure, eliminating approximately (12) farm taps and (2) above-ground regulator stations in a high-traffic business district.

KY Farm Tap projects - per PHMSA amended 192.740 regulation (published 3/24/17) titled 'Pressure regulating, limiting, and overpressure protection - Individual service lines directly connected to a production, gathering, or transmission pipeline' (AKA 'Farm Tap Rule'), operators have 3 years to rebuild or modify 'Farm Tap' stations to be routinely inspected every 3 years using the same criteria as distribution system stations. Atmos Energy has approximately 928 farm taps to rebuild/replace and has budgeted work in several cost centers in order to meet this regulatory deadline.

For further explanation, please see the testimony of Greg Waller at the Hearing in Case No. 2017-00349 on the hearing video from approximately 4:23 - 4:29 (run time) which occurred from approximately 2:35 - 2:41 PM on March 22, 2018.

<u>ATTACHMENT:</u>

ATTACHMENT 1 - Atmos Energy Corporation, Staff_3-22_Att1 - Non-PRP Investment FY18 vs. FY19.xls, 5 Pages.

Respondents: Greg Smith and Greg Waller

Atmos Energy Corporation
Kentucky/Mid-States Division
Kentucky Operations
Case No. 2018-00281
Staff 3-22 Part B
Non-PRP Investment FY18 vs. FY19 (in Million $)

Sum of Amount ($ Millions)			Fiscal Year	
CB Department	CB Description	CB Budget Cat	2018	2019
2609	2609.Abandon Taps.FY19	System Integrity		$0.044
	2609.ANR.Bon Harbor	System Improvements	$2.416	$8.655
	2609.Bypass Hoses.FY19	Equipment		$0.007
	2609.Contacter Replacement	System Integrity		$0.513
	2609.Equipment.FY18	Equipment	$0.025	
	2609.Farm Taps.FY19	System Integrity	$0.004	$2.748
	2609.Grandview Well Workover	System Integrity	($0.001)	
	2609.Leak.Functional	System Integrity	$0.001	
	2609.Midwestern.Trans.Boiler	System Improvements	$0.115	
	2609.Stonebore Methanol Pumps	Equipment		$0.018
	2609.Wescor 6" Exposure.FY19	System Improvements		$0.185
	BonHarbor.P&A 3 Wells.WO BH7	System Integrity	($0.000)	
	Grandview Well Workover.FY18	System Integrity	$0.228	$0.547
	Hickory.Junction Valve Repl.17	System Integrity	$0.018	
	Odorant Tank Disposal - FY19	System Integrity		$0.118
2609 Total			$2.806	$12.833
2612	2612.Gas Supply RTU Install	System Improvements		$0.091
	2612.KY.Corrector Repl.FY19	System Improvements		$0.044
	2612.KY.Corrector.Repl.FY18	System Improvements	$0.054	
	2612.KY.ECAT Replacement.FY17	System Improvements	$0.000	
	2612.KY.Emergency.Regulators	System Improvements	$0.022	
	2612.KY.RTU Upgrades.FY18	System Improvements	$0.056	
	CB18.2612.01.EQ.009	Equipment	$0.016	
	KY.East Diamond.RTU Upgrade	System Improvements		$0.056
	KY.Emergency Regulators.FY19	System Improvements		$0.029
	KY.Hudson.Foods RTU Upgrade	System Improvements		$0.023
	Truckline.KY.RTU.Uprgrade	System Improvements		$0.026
2612 Total			$0.147	$0.269
2634	2634.41A Phase II.FY19	Public Improvements		$0.297
	2634.Crystal Gauges.FY19	Equipment		$0.007
	2634.Equipment.FY18	Equipment	$0.065	
	2634.ERXs Purchase.FY19	System Integrity		$0.009
	2634.Gas Tracker.FY19	Equipment		$0.024
	2634.Growth.Functional	Growth	$0.217	$0.158
	2634.Jamison Tracker 800.FY19	Equipment		$0.003
	2634.Juno WMR.FY19	Equipment		$0.006
	2634.Leak.Functional	System Integrity	$0.042	$0.136
	2634.Misc Growth Mains.FY19	Growth		$0.001
	2634.Misc.Growth.FY18	Growth	$0.006	
	2634.Misc.SysInt.Mains.FY18	System Integrity	$0.269	
	2634.Misc.SysInt.Mains.FY19	System Integrity		$0.001
	2634.Misc.Syst.Integ.Main.FY17	System Integrity	($0.004)	
	2634.Non.Growth.Functional	System Integrity	$0.469	$0.480
	2634.Office.Repairs	Structures	$0.014	
	2634.Poole Purchase Replace	System Improvements		$0.067
	2634.Poole TB Replacement	System Improvements		$0.057
	2634.Thonridge Rucker#1.FY17	System Improvements	($0.000)	
	2634.Town Border 2 Replacement	System Improvements		$0.166
	2634.YZ Purchase Cover.FY18	Structures	$0.003	
	TO Williamson Tapping.FY19	Equipment		$0.064
	Warehouse Office Remodel.FY19	Structures		$0.088
	WMR.2634.Dixon Tower.FY19	System Improvements		$0.079
	WMR.2634.Endpoints.FY17	System Improvements	$0.005	
	WMR.2634.Spottsville Base.FY19	System Improvements		$0.036
2634 Total			$1.088	$1.680
2635	2635.Equipment.FY18	Equipment	$0.018	
	2635.Equipment.FY19	Equipment		$0.021
	2635.Growth.Functional	Growth	$0.098	$0.048
	2635.Leak.Functional	System Integrity	$0.022	$0.080
	2635.Misc Growth Mains.FY19	Growth		$0.001
	2635.Misc.Growth.FY18	Growth	$0.010	
	2635.Misc.SysInt.Mains.FY19	System Integrity		$0.001
	2635.Misc.Syst.Integ.Main.FY17	System Integrity	($0.000)	
	2635.Non.Growth.Functional	System Integrity	$0.241	$0.363
	2635.Reg.Cover Dawson Springs	Structures	$0.004	
	2635.WMR.Endpoints.FY18	System Improvements	$0.618	
	Dawson Springs System Tie Back	System Integrity		$0.167
	WMR.2635.Towers.FY18	System Improvements	$0.124	
2635 Total			$1.135	$0.682
2636	050.2636.Gateway.Commons	System Improvements	$0.049	
	2636.5th. St. System Improv.	System Improvements	$0.020	
	2636.Bentree Tie Back.FY19	System Improvements		$0.053
	2636.Boothfield Rd. Tie Back	System Improvements		$0.053

Atmos Energy Corporation
Kentucky/Mid-States Division
Kentucky Operations
Case No. 2018-00281
Staff 3-22 Part B
Non-PRP Investment FY18 vs. FY19 (in Million $)

Sum of Amount ($ Millions)			Fiscal Year	
CB Department C	CB Description	CB Budget Cat	2018	2019
	2636.Building Access Upgrade	Structures		$0.030
	2636.Burton Rd Station.FY19	System Improvements		$0.037
	2636.Equipment.FY19	Equipment		$0.047
	2636.Fairview.Spur.Reg.FY17	System Improvements	$0.014	
	2636.FY18 Equipment	Equipment	$0.055	
	2636.Gas Tracker.FY19	Equipment		$0.024
	2636.Growth.Functional	Growth	$0.843	$1.134
	2636.Leak.Functional	System Integrity	$0.266	$0.376
	2636.Misc Growth Mains.FY19	Growth		$0.122
	2636.Misc.Growth.FY18	Growth	$0.125	
	2636.Misc.Growth.Main.Ext.FY17	Growth	$0.049	
	2636.Misc.SysInt.Mains.FY18	System Integrity	$0.433	
	2636.Misc.SysInt.Mains.FY19	System Integrity		$0.006
	2636.Non.Growth.Functional	System Integrity	$1.550	$1.589
	2636.Parking Lot Sealing.FY19	Structures		$0.008
	2636.Settles Rd.Tie Back.FY19	System Improvements		$0.026
	2636.T. D. Williamson.FY19	Equipment		$0.036
	Breckenridge.Co.Ind.Park.TBS	System Integrity	$0.002	
	Hartford Purchase YZ Injector	System Integrity	$0.068	
	Midwest Purch 6 Valve Repl.	System Integrity	$0.056	
	Owensboro Warehouse Lighting	Structures		$0.009
	WMR.2636.Cental.City.Endpoints	System Improvements	$0.213	
	WMR.2636.Central.City.Tower	System Improvements	$0.060	
2636 Total			$3.803	$3.549
2637	040.009 MEC Forfeiture	Growth	($0.131)	
	2637.Blandville Rd Widening	System Integrity		$0.005
	2637.CalvertCity Purch Rebuild	System Integrity	$0.600	$0.389
	2637.Equipment.FY18	Equipment	$0.105	
	2637.Equipment.FY19	Equipment		$0.042
	2637.ERX Purchase.FY18	System Improvements	$0.018	
	2637.Estes Lane Reinforcement	System Integrity		$0.129
	2637.Forsythia Farm Taps.FY18	System Integrity	$0.059	
	2637.Grade 3 Leak Repairs.FY18	System Integrity	$0.149	
	2637.Grand Rivers WMR Tower	System Improvements	$0.037	
	2637.Growth.Functional	Growth	$0.634	$0.621
	2637.Hwy 282 Main Repl.FY18	System Integrity	$0.040	
	2637.KY Farm Taps.FY19	System Integrity		$0.523
	2637.Leak.Functional	System Integrity	$0.302	$0.282
	2637.Meredith Rd Reg.Stat.FY18	System Improvements	$0.018	
	2637.Misc Growth Mains.FY19	Growth		$0.185
	2637.Misc.Growth.FY18	Growth	$0.165	
	2637.Misc.Growth.Main.Ext.FY16	Growth	$0.000	
	2637.Misc.Growth.Main.Ext.FY17	Growth	$0.031	
	2637.Misc.SysInt.Main.FY18	System Integrity	$0.122	
	2637.Misc.SysInt.Mains.FY19	System Integrity		$0.001
	2637.Misc.Syst.Integ.Main.FY17	System Integrity	($0.001)	
	2637.Non.Growth.Functional	System Integrity	$1.280	$1.101
	2637.Odorant Tank Disposal.18	System Improvements	$0.074	
	2637.Un-tonable Pipe Repl.FY19	System Integrity		$0.201
	2637.WKCTC Pipe Replacement	System Integrity		$0.106
	2637.WMR Tower.FY19	System Improvements		$0.061
	CB13.2637.01.GR.009	Growth	$0.002	
	Husband.Rd.Replacement.18	System Integrity	$0.033	
	Hwy 62 Widening Calvert City	Public Improvements	$0.106	
	Massac Creek Crossing.FY19	System Integrity	$0.001	$0.566
	Paducah Grade #3 Leaks.FY19	System Integrity		$0.043
	Paducah Isolation Valves.FY19	System Integrity		$0.010
	Paducah Mall & Creek HCA	System Integrity		$7.207
	Windsor Square.HCA12.FY16	System Integrity	($0.000)	
2637 Total			$3.644	$11.470
2638	2638.63 FV Replacements.FY19	System Integrity		$0.029
	2638.Beadlestown Purchase.FY17	System Improvements	$0.115	
	2638.Equipment.FY18	Equipment	$0.011	
	2638.Equipment.FY19	Equipment		$0.004
	2638.Growth.Functional	Growth	$0.115	$0.120
	2638.Leak.Functional	System Integrity	$0.048	$0.077
	2638.Mayfield ERX.2018	System Improvements	$0.020	
	2638.Mayfield Heater Repl.FY19	System Improvements		$0.272
	2638.MAYFIELD. GROWTH MAINS	Growth	$0.005	
	2638.Misc Growth Mains.FY19	Growth		$0.001
	2638.Misc.Growth.FY18	Growth	$0.062	
	2638.Misc.Growth.Main.Ext.FY15	Growth	$0.004	
	2638.Misc.Growth.Main.Ext.FY16	Growth	$0.003	

CASE NO. 2018-00281
ATTACHMENT 1
TO STAFF DR NO. 3-22

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Kentucky Operations
Case No. 2018-00281
Staff 3-22 Part B
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Sum of Amount ($ Millions)			Fiscal Year	
CB Department C	CB Description	CB Budget Cat	2018	2019
	2638.Misc.Growth.Main.Ext.FY17	Growth	$0.000	
	2638.Misc.SysInt.Main.FY18	System Integrity	$0.091	
	2638.Misc.SysInt.Mains.FY19	System Integrity		$0.001
	2638.Murray St Replacement	System Integrity		$0.093
	2638.Non.Growth.Functional	System Integrity	$0.434	$0.471
	2638.Repair Grade 3 Leaks.FY18	System Integrity	$0.041	
	2638.South Reinforcement Ph. 2	System Improvements	$0.924	
	2638.South Reinforcement.FY17	System Improvements	$0.006	
	2638.Southern Bypass.FY18	Public Improvements	($0.044)	
	2638.Wingo Purchase Upgrade	System Integrity	$0.154	
	Hardeman Creek Crossing.FY19	System Integrity	$0.001	$0.041
	Hardeman Hwy 1710 Farm Taps	System Integrity		$0.062
	Symsonia Creek Crossing.FY19	System Integrity	$0.001	$0.041
2638 Total			$1.991	$1.146
2734	2734.Auburn Purchase.Stat.FY18	System Integrity	$0.146	
	2734.BG Center Line Phase 3	System Integrity		$1.121
	2734.BG Farm Taps.FY19	System Integrity		$1.056
	2734.Elkton TBS.FY17	System Improvements	$0.041	
	2734.Equipment.FY17	Equipment	$0.000	
	2734.Equipment.FY18	Equipment	$0.076	
	2734.FY19.Equipment	Equipment		$0.113
	2734.FY19.Structure	Structures		$0.011
	2734.Growth.Functional	Growth	$0.954	$1.216
	2734.Leak.Functional	System Integrity	$0.364	$0.255
	2734.McGinnis Quarry Rd.Reinf.	System Improvements	$1.147	
	2734.Misc Growth Mains.FY19	Growth		$0.294
	2734.Misc.Growth.FY18	Growth	$0.202	
	2734.Misc.Growth.Main.Ext.FY14	Growth	($0.002)	
	2734.Misc.Growth.Main.FY17	Growth	$0.025	
	2734.Misc.SysInt.Mains.FY18	System Integrity	$0.018	
	2734.Misc.SysInt.Mains.FY19	System Integrity		$0.009
	2734.Misc.Syst.Integ.Main.FY17	System Integrity	$0.001	
	2734.Non.Growth.Functional	System Integrity	$1.162	$1.091
	2734.Scottsville.Rd.Extension	Growth	$0.114	
	2734.Small House Relo.FY18	Public Improvements	$0.657	
	2734.Structures.FY18	Structures	$0.034	
	2734.Three Springs Rd TBS	System Improvements		$0.234
	Beechbend Rd. Reinforcement	System Improvements		$0.159
	BG Purchase Stat. 1 Replc.FY17	System Improvements	$0.044	
	Logan Aluminum Upgrade	System Improvements	$0.047	
	McGinnis Quarry Rd TGT Tap	System Improvements	$0.851	
	Potty Rd to JC Kirby Cemetery	System Improvements		$0.585
	Plano Rd to Scottsville Rd	System Improvements		$2.510
	Plano.Rd.System Improv.	System Improvements	$0.003	
	Russellville Rd.Dishman.Tie-In	System Improvements	$0.008	
	Wilkey Industrial Park.FY17	Growth	$0.011	
	WMR.2734.Endpoints.FY19	System Improvements		$1.183
	WMR.2734.Towers.FY19	System Improvements		$0.697
2734 Total			$5.901	$10.532
2735	2735.Akebono Meter Set	System Improvements		$0.116
	2735.Cave City Tie-In	System Improvements	$0.051	
	2735.Equipment FY19	Equipment		$0.028
	2735.Equipment.FY18	Equipment	$0.014	
	2735.FY19.Glasgow ERX	System Improvements		$0.029
	2735.Glasgow Farm Taps FY19	System Integrity		$0.637
	2735.Growth.Functional	Growth	$0.089	$0.076
	2735.Hiseville.TBS.Replc	System Integrity	$0.037	
	2735.Leak.Functional	System Integrity	$0.142	$0.094
	2735.Misc Growth Mains.FY19	Growth		$0.001
	2735.Misc.Growth.FY18	Growth	$0.004	
	2735.Misc.SysInt.Mains.FY19	System Integrity		$0.001
	2735.Misc.Syst.Integ.Main.FY17	System Integrity	$0.044	
	2735.Non.Growth.Functional	System Integrity	$0.276	$0.210
	2735.Oakland Town Border	System Improvements		$0.076
2735 Total			$0.657	$1.270
2736	050.2736.Central Ave.FY18	System Integrity		$0.695
	2736.Calvin Dr.Reg.Stat.FY17	System Integrity	($0.001)	
	2736.East 19th St.FY19	System Improvements		$0.696
	2736.Equipment.FY18	Equipment	$0.069	
	2736.Equipment.FY19	Equipment		$0.022
	2736.Growth.Functional.	Growth	$0.165	$0.107
	2736.Hopkinsville KY Office	Structures	$0.535	
	2736.HWEA Inspection.FY19	Public Improvements		$0.266

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CB Department C	CB Description	CB Budget Cat	2018	2019
	2736.Leak.Functional.	System Integrity	$0.086	$0.248
	2736.Misc Growth Mains.FY19	Growth		$0.001
	2736.Misc.Growth.FY18	Growth	$0.033	
	2736.Misc.Growth.Main.FY17	Growth	$0.003	
	2736.Misc.SysInt.Mains.FY18	System Integrity	$0.002	
	2736.Misc.SysInt.Mains.FY19	System Integrity		$0.002
	2736.Non.Growth.Functional.	System Integrity	$0.346	$0.297
	2736.Nortonville T.B. Station	System Improvements		$0.108
	2736.Structures.FY19	Structures		$0.050
	Hopkinsville Warehouse Repl.	Structures	$0.106	
	Nortonville 1st Cut Station	System Improvements		$0.106
	WMR.2736.Endpoints.FY18	System Improvements	$0.265	
	WMR.2736.Endpoints.FY19	System Improvements		$0.566
	WMR.2736.Tower.FY18	System Improvements	$0.109	
2736 Total			$1.717	$3.158
2737	2737.2nd St. Bridge Repl.FY18	System Integrity	$0.118	
	2737.Burgin Town Border	System Integrity		$0.071
	2737.Caldwell Rectifier.FY18	System Integrity	$0.006	
	2737.Equipment FY19	Equipment		$0.036
	2737.Equipment.FY18	Equipment	$0.031	
	2737.FY19.Danville ERX	System Improvements		$0.039
	2737.Growth.Funct.	Growth	$0.115	$0.097
	2737.Hustonville Adyl A Replc	System Integrity		$0.555
	2737.Hwy 150 West.FY18	System Improvements	$0.230	
	2737.Leak.Funct.	System Integrity	$0.088	$0.146
	2737.Misc Growth Mains.FY19	Growth		$0.001
	2737.Misc.Growth.FY18	Growth	($0.001)	
	2737.Misc.Growth.Main.FY17	Growth	($0.000)	
	2737.Misc.SysInt.Mains.FY19	System Integrity		$0.001
	2737.Non.Growth.Funct.	System Integrity	$0.430	$0.724
	2737.Office Asphalt ParkingLot	Structures	$0.068	
	2737.TBS REPLACEMENTS.FY17	System Improvements	$0.696	
2737 Total			$1.782	$1.669
2738	2738.Broadway Relocation.FY18	Public Improvements	$0.612	
	2738.Bypass Relocation	Public Improvements	$0.073	
	2738.Equipment.FY18	Equipment	$0.015	
	2738.Equipment.FY19	Equipment		$0.038
	2738.FY19.Campbellsville ERX	System Improvements		$0.027
	2738.Greensburg Town Borders	System Improvements		$0.189
	2738.Growth.Functional	Growth	$0.159	$0.100
	2738.Leak.Functional.	System Integrity	$0.050	$0.043
	2738.Misc Growth Mains.FY19	Growth		$0.001
	2738.Misc.Growth.FY18	Growth	$0.023	
	2738.Misc.Growth.Main.FY17	Growth	($0.003)	
	2738.Misc.SysInt.Mains.FY19	System Integrity		$0.001
	2738.Non.Growth.Functional.	System Integrity	$0.282	$0.363
	2738.Warehouse Modification	Structures	$0.056	
	Hodgenville Rd. Reinforcement	System Improvements		$0.413
	Saloma HPD Line Exposures	System Integrity		$0.491
	Saloma Purchase Station.FY19	System Integrity	$0.014	$0.316
	Summersville Purch Stat.FY19	System Integrity	$0.012	$0.309
2738 Total			$1.294	$2.292
2739	2739.Equipment.FY18	Equipment	$0.040	
	2739.Equipment.FY19	Equipment		$0.026
	2739.FY19.Shelbyville ERX	System Improvements		$0.021
	2739.Growth.Functional	Growth	$0.360	$0.390
	2739.Hwy 53 to Lat Line 12 HPS	System Integrity	($0.052)	
	2739.Hwy53 to Waddy Line Ph 2	System Improvements	$6.986	$4.219
	2739.Leak.Functional	System Integrity	$0.013	$0.040
	2739.Martinrea Town Border	System Integrity		$0.219
	2739.Misc Growth Mains.FY19	Growth		$0.089
	2739.Misc.Growth.FY18	Growth	$0.082	
	2739.Misc.Growth.Main.Ext.FY16	Growth	$0.000	
	2739.Misc.Growth.Main.FY17	Growth	$0.021	
	2739.Misc.SysInt.Mains.FY19	System Integrity		$0.001
	2739.Non.Growth.Functional	System Integrity	$0.178	$0.399
	2739.Osprey Cove Reinforcement	System Improvements		$0.278
	2739.Shelbyville Low Pressure	System Improvements		$0.421
	CB11.2739.14.SINT.009	System Integrity	$0.002	
	Shelbyville Farm Taps.FY19	System Integrity		$1.114
	Shelbyville.Purch.Stat.Upgrade	System Improvements	$0.206	
2739 Total			$7.836	$7.218
3302	3302.Ky Laptops Fall.FY18	Information Technology	$0.024	

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3302	3302.KY.Desktops.FY19	Information Technology		$0.021
	3302.KY.Laptops.FY19	Information Technology		$0.020
	3302.KY.MDT.FY19	Information Technology		$0.072
	3302.KY.MDTs.Spring.FY18	Information Technology	$0.058	
	3302.KY.Phone.System.Repl.FY17	Information Technology	$0.007	
	3302.KY.Server.Repl.FY18	Information Technology	$0.021	
	3303.KY.Laptops.Spring.FY18	Information Technology	$0.019	
3302 Total			$0.130	$0.112
Grand Total			$33.931	$57.879