BEFORE THE

PUBLIC SERVICE COMMISSION OF THE

COMMONWEALTH OF KENTUCKY

IN RE:	**APPLICATION OF ATMOS ENERGY**	**)**	
	CORPORATION FOR AN	**)**	**CASE NO. 2017-00349**
	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 17, 2018

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DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

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

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

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

Q. 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 been actively involved and testified on dozens of occasions on specific income tax and normalization issues. I have worked, on behalf of utility customers and together with utility counsel, to draft requests for Internal Revenue Service ("IRS") Private Letter Rulings ("PLRs") on normalization issues. I have met with, on behalf of utility customers, Senior Technician Reviewers in the IRS Office of the Associate Chief Counsel (Passthroughs and Special Industries), in conferences of right. I have developed and presented comments before the Treasury Department and the IRS, on behalf of utility customers, regarding proposed rulemakings and income tax normalization requirements. In addition, 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, and Louisville Gas and Electric Company. Further, I have testified before the Georgia Public Service Commission in multiple Atmos base rate proceedings.[1] Finally, I testified in the most recent Columbia Gas rate case (2016-00152) and the most recent Atmos base rate case prior to this proceeding (2015-00343).

Q. On whose behalf are you testifying?

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

A. I am offering 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 the AG's base rate reduction recommendation, 2) address and make recommendations on specific issues that affect the base revenue requirement in this proceeding, 3) quantify the effects of AG witness Mr. Richard Baudino's recommendations, 4) address the Company's request for a new Annual Review Mechanism ("ARM") rider that would replace the Company's present Pipeline Replacement Program ("PRP") rider, 5) address concerns with the present PRP rider, and 6) address the Company's request to increase the present Research and Development ("R&D") rider.

Q. Please summarize your testimony.

A. I recommend a base rate *reduction* of $16.937 million compared to the Company's request for a base rate increase of $10.363 million, as corrected in response to AG discovery. The following table provides a summary of the revenue effects of the AG's recommendations.

Atmos Energy Corporation - Kentucky Division **Summary of Attorney General Recommendations** **KPSC Case No. 2017-00349** **Test Year Ended March 31, 2019**	
Atmos Requested Increase	
Atmos Request Based on Original Filing	$ 10,416,024
Atmos Modification of Request to Correct Filing Errors - Response to Staff 2-37	(53,216)
Atmos Modified Request Amount to Correct Filing Errors - Response to Staff 2-37	$ 10,362,808
Effects on Increase of AG Rate Base Recommendations	
Reduce Forecast 12% Escalation on Capital Additions for Kentucky Non-PRP Oct 2018-Mar 2019	$ (53,890)
Reflect Changes in Net Salvage - Effects on A/D Net of ADIT	101,319
Remove Account 190 ADIT Not Associated With Cost of Service	(119,587)
Include Temporary Differences Associated With 190 ADIT Included in Cost of Service	(608,340)
Remove NOL ADIT in Acct 190	(3,741,762)
Reflect Cash Working Capital Based on Corrected Lead Lag Study	(658,905)
Remove Prepayments	(167,053)
Remove Rate Case Regulatory Asset	(22,733)
Effects on Increase of AG Operating Income Recommendations	
Remove Amortization Expense for Rate Case Regulatory Asset	(158,048)
Reduce Kentucky Division O&M Expense	(566,638)
Reduce Mid-States Division O&M Expense Allocated to Kentucky Division	(837,684)
Remove Directors Stock Expense	(347,235)
Reduce Retirement Plan Expenses	(579,127)
Reduce Income Tax Expense to Reflect Reduction in Federal Income Tax Rate	(6,796,256)
Reduce Income Tax Expense to Amortize Excess ADIT	(2,934,943)
Reduce Escalation in Ad Valorem Taxes	(543,158)
Amortize Def Interest Expense from Annualizing March 2019 Refinancing Interest Savings	101,641
Adjust Depreciation Expense to Remove Forecast 12% Escalation on Non-PRP Capital Additions	(21,450)
Reduce Depreciation Expense to Reflect Changes in Net Salvage	(3,531,704)
Include AEC Commitment and Banking Fees in Operating Income	136,362
Effects on Increase of AG Rate of Return Recommendations	
Remove Commitment Fee and Administrative Expense from Cost of Short Term Debt	(150,204)
Reduce Long Term Debt Rate by Reflecting Redemption and Reissue of High Interest Debt	(1,088,982)
Reflect Return on Equity of 8.80%	(3,972,019)
Effects of Change In Composite Allocation Factor - All Aspects of Revenue Requirement	(739,808)
Total AG Recommendations	$ (27,300,205)
AG Recommendation to Reduce Base Rates	$ (16,937,397)

I address all the rate base and operating income AG recommendations reflected on the preceding table, except for the rate of return recommendations, which are addressed by AG witness Mr. Richard Baudino. I also quantify the effects on the revenue requirement of the rate of return recommendations addressed by Mr. Baudino. In addition, I recommend that the Commission reject the Company's request for a new ARM rider. Further, I recommend that the Commission make changes to limit the annual percentage increases that can be implanted through the PRP rider or consider terminating it. Finally, I recommend that the Commission terminate the R&D rider, or alternatively, reject the Company's request to increase the rider. I have structured my testimony to sequentially address these issues.

II. RATE BASE ISSUES

A. Escalation Rate of 12% for Non-PRP Plant Additions Is Excessive and Should Be Reduced

Q. Describe how the Company developed its forecast of gross plant for the test year and how this forecast affects the rate base and depreciation expense proposed by the Company.

A. Company witness Mr. Gregory K. Waller described how the Company developed the forecast of gross plant as follows:

> I used the capital spending projection for July-September 2017 and the recently approved fiscal year 2018 budget for the months in fiscal year 2018 (October 2017 through September 2018). For the months of October 2018-March 2019, I added plant additions in monthly amounts twelve percent greater than the previous year's

> budget for Kentucky direct investment, and in monthly amounts equal to the previous year's budget for Shared Services and Division office investment.[2]

The 12% escalation rate was applied for the six-month period to non-PRP capital spending. The Company did not include projected PRP capital expenditures for this six-month period in the test year gross plant for the base revenue requirement because it plans to include these PRP expenditures in the PRP rider when its tariff rates are reset later this year.

The Company added these capital expenditures to gross plant and reflected the 13-month average in rate base. In addition, the Company calculated depreciation expense on these plant additions, which it included in depreciation expense. Further, the Company calculated the related increases in accumulated depreciation and accumulated deferred income taxes ("ADIT) and reflected the 13-month averages as subtractions from rate base.

Q. Is this escalation rate reasonable?

A. No. It is four to six times greater than projected inflation of approximately 2%-3%. In other words, the Company proposes increases in capital expenditures in the final six months of the test year that exceed the capital expenditures in the prior year adjusted for

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[2] Direct Testimony of Gregory K. Waller at 12.

inflation. These projects are not identified; they are merely projected based on this inexplicable assumption.

Once the Company is granted a rate increase on the basis of this assumption, it is not obligated to spend this amount. If it does not, then it retains the additional revenue in excess of the revenue requirement necessary for the actual capital expenditures. There is no true-up to actual.

Q. What is your recommendation?

A. I recommend that the Commission reject the escalation rate proposed by the Company and instead reflect the same level of capital expenditures for these months in the test year as were reflected in the Company's most recent capital expenditure budget.

Q. What is the effect of your recommendation?

A. The effect is a reduction in the revenue requirement of $0.075 million, consisting of $0.054 million for the grossed-up return and $0.021 million for depreciation expense.[3]

B. Accumulated Deferred Income Taxes and Temporary Differences (Liabilities) Subtracted from Rate Base Are Understated and Should Be Increased

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

Q. Please provide a description of accumulated deferred income taxes and how they are recognized for ratemaking purposes.

A. There are both accumulated deferred income tax liabilities ("DTLs") and accumulated deferred income tax assets ("DTAs"). DTLs generally are subtracted from rate base because they represent cost-free capital to the utility and DTAs generally are added to rate base because they must be financed by the utility, although there are exceptions to this general ratemaking practice if the related costs are not included in the revenue requirement.

If the Company improperly adds certain DTAs to rate base, then the net accumulated deferred income taxes subtracted from rate base are understated and rate base and the revenue requirement are overstated. Similarly, if the Company correctly adds certain other DTAs to rate base, but fails to subtract the related temporary differences, or liabilities, that gave rise to the DTAs, then the rate base and revenue requirement are overstated.

DTLs represent deferred income tax amounts that will be paid to federal and state governments by the utility in future years and reflect the accumulation of deferred income tax expense, one of two components in the calculation of income tax expense. These amounts typically are recorded in accounts 281, 282, and 283 pursuant to the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts

("USOA").

DTLs represent the tax effects of temporary, or timing, differences where income is deferred or deductions are accelerated on the income tax returns compared to the recognition of income and expenses for accounting purposes. In this case, the temporary difference reduces *current* income tax expense, but is offset by an equivalent *deferred* income tax expense. The deferred tax expense related to each temporary difference is accumulated as a separately identified DTL. For example, a utility will deduct accelerated or bonus tax depreciation on its tax return, but will record straight line depreciation for accounting purposes. The temporary difference for the excess of the tax depreciation over the accounting depreciation is a deduction to taxable income and reduces current income tax expense. This same temporary difference is multiplied times the federal and state income tax rates to calculate the deferred tax expense and then added to the DTL. At some point in the future, the tax depreciation for those same assets will be less than the accounting depreciation, the deferred tax expense will be negative, and the DTL will reverse, and ultimately decline to zero when the assets are fully depreciated for both tax and accounting purposes.

DTAs represent prepaid income tax amounts that will be refunded by the federal and state governments to the utility in future years. These amounts are typically recorded in account 190 pursuant to the FERC USOA. DTAs represent the tax effects of temporary, or timing, differences where income is accelerated and deductions are delayed on the income tax returns compared to the recognition of income and expenses for accounting purposes. In other words, the temporary differences for DTAs are the opposite of the temporary differences for DTLs. In this case, the temporary difference increases current income tax expense, but is offset by an equivalent reduction in deferred tax expense, and the deferred tax expense related to each temporary difference is accumulated as a separately identified DTA. At some point in the future, the specific temporary differences giving rise to the DTAs will reverse, and ultimately, the DTAs will decline to zero when the income or deduction is fully recognized for tax and accounting purposes.

It should be noted that many temporary differences are recurring, i.e., they are deferred in one month or year, then are reversed the following month or year, and then are followed by another deferral in the next month or year and another reversal.

Q. Have you reviewed the DTL and DTA amounts that the Company included in rate base?

A. Yes. The Company included the entirety of the DTAs and DTLs projected for the test year in accounts 190, 281, 282, and 283 originating in all divisions (002 and *012 Shared Services*, 009 *Kentucky/Midstates*, and 091 for Kentucky), except for the DTL related to the gas over/under recovery and the DTA related to the net operating loss ("NOL") "attributable to the Company's unregulated business."[4] The Company included the NOL DTA attributable to the Company's regulated business.

The Company provided DTAs and DTLs by temporary difference and account for each division in response to Staff discovery.[5] I reviewed this detail and identified numerous DTAs that should not be included in rate base for Division 002 *Shared Services* and Division 091 *Kentucky/Mid States*. I also identified numerous DTAs that should be included in rate base, but only if the related temporary difference is subtracted from rate base, for Divisions 002 and 091; otherwise they should not be included in rate base.

The Division 002 DTA amounts that were improperly included in rate base are due to the following temporary differences: Management Incentive Plan ("MIP") and Variable Pay Plan ("VPP") expense, SEBP adjustment, restricted stock grant plan expense, Rabbi Trust, restricted stock – MIP expense, Director's stock awards expense, charitable contribution expense carryover, and VA charitable contributions expense.[6]

The Division 012 DTA amount that was improperly included in rate base is due

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[4] Direct Testimony of Gregory K. Waller at 20.

[5] Company's workpaper "ADIT_for_KY_-_2017" provided in response to Staff 1-71.

[6] Company's response to AG 1-33. The Company also improperly included the DTA for the net operating loss ("NOL") temporary difference. I separately address this DTA in the following section of my testimony due to its significance and the Company's claim that it must be included in rate base to avoid a normalization violation. The Company's response to AG 1-33 provides a detailed description of these temporary differences and the Company's rationale for including the related ADIT or its concession that it would not oppose the removal of the ADIT from rate base. I have attached a copy of this response as my Exhibit___(LK-2).

to the following temporary difference: MIP/VPP expense.[7]

The Division 091 DTA amounts that were improperly included in rate base are due to the following temporary differences: MIP and VPP expense, charitable contribution expense carryover, and regulatory asset expense.[8]

The Division 009 DTA amount that was improperly included in rate base is due to the following temporary difference: MIP/VPP expense.[9]

Q. Why should the Commission exclude these DTAs from rate base?

A. In general, these DTAs are related to costs that are not recovered through the ratemaking process. None of the costs giving rise to these DTAs are included in operating expenses or subtracted from rate base in the determination of the revenue requirement. Thus, neither the DTAs should be added to rate base nor the temporary differences subtracted from rate base.

In addition, the DTA related to the VA charitable contributions (even though it was a DTL recorded in account 190) in its former Virginia jurisdiction is not a cost of the Kentucky rate division. Instead, it should have been directly assigned to the Virginia

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[7] Company's response to AG 1-35 provides a detailed description of the temporary differences and the Company's rationale for including the related ADIT or its concession that it would not oppose the removal of the ADIT from rate base. I have attached a copy of this response as my Exhibit___(LK-3).

[8] Company's response to AG 1-34 provides a detailed description of the temporary difference and the Company's rationale for including the related ADIT or its concession that it would not oppose the removal of the ADIT from rate base. I have attached a copy of this response as my Exhibit___(LK-4).

[9] Company's response to AG 1-35.

rate divisions.

Further, the DTA related to the VA charitable contributions is due to a below the line expense and should be excluded from rate base for that reason as well.

Q. Did you identify a second category of errors?

A. Yes. For other DTAs, the Company failed to subtract from rate base the related temporary differences that gave rise to the DTAs. This violates the basic ratemaking principle of matching benefits and costs and fails to provide customers a rate of return on the expenses recovered in rates, but retained by the utility as a liability until paid at a later date. This is not a problem with the DTAs, but rather, is due to the Company's failure to subtract the related temporary differences from rate base.

The DTAs do not exist in a vacuum. The only reason the utility has the DTA is because the accounting expense is accrued, but not recognized as a deduction for income tax purposes until it actually is paid. The utility accrues a liability to pay the expenses recovered from customers, which is released when the liability is paid. The deduction for income tax purposes also is taken when the liability is paid and the DTA is reversed.

For these DTAs, the correct ratemaking is to subtract the liabilities, or temporary differences, from rate base and to add, or include, the DTAs in rate base. If the liabilities are not subtracted from rate base, then the related DTAs also should be excluded (not added to rate base), along with the other DTAs in the first category that I described.

The DTA and related temporary differences in this second category include the self-insurance expense (accrual for reserve accounting) and Rabbi Trust expense (002 Division),[10] and Reg Asset Benefit Accrual (Division 091).[11] However, if the Commission does not agree with the AG that the SEBP (002 and 091 Divisions) and Directors stock awards expense (002 Division) should be disallowed, which I address in the Operating Income Issues section of my testimony, then the DTAs and related temporary differences in this second category also will include the liabilities related to these expenses.

Q. Does the Company agree that certain of the DTAs in the first category should be excluded from rate base?

A. Yes. The Company stated in response to discovery that it would not oppose adjustments to exclude the DTAs for MIP/VPP accrual, restricted stock grant plan, restricted stock - MIP, charitable contribution carryover, and VA charitable contributions from rate base.[12]

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[10] Company's response to AG 1-33.
[11] Company's response to AG 1-34.
[12] Company's response to AG 1-33.

Q. Does the Company agree that the DTAs in the second category should be excluded from rate base or that the related temporary differences be subtracted from rate base?

A. No. The Company claims that these DTAs should be included in rate base because the expenses are included in operating income.[13] Although the expenses are included in the revenue requirement, that is not a sufficient reason to justify the addition of these DTAs in rate base, as I previously explained. The liabilities resulting from the delayed payment of the expenses must be subtracted from rate base; otherwise the DTAs should be excluded (not added) from rate base. The liabilities are the temporary differences that gave rise to the DTAs. You cannot include the DTAs in rate base without including the temporary differences in rate base.

Q. Have you quantified the effects on the revenue requirement of excluding the DTAs in the first category from rate base?

A. Yes. The effects for each DTA and in total are summarized on the following table.[14]

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[13] Company's responses to AG 1-33, 1-34, and 1-35.
[14] The quantifications of these amounts are reflected in my electronic workpapers, which were filed along with my testimony.

Atmos Energy Corporation - Kentucky Division
AG Recommendation to Exclude Certain DTAs from Rate Base
KPSC Case No. 2017-00349
Test Year Ended March 31, 2019
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See Responses to AG 1-33, 1-34, 1-35

Division 002 Balances as Filed in Account 190 ADIT (Positive Value = Debit Balance)

	DTA	As-Filed Jurisdictional Allocator	DTA Allocation to KY Division	Grossed-Up Rate of Return Using 21% Fed	DTA Revenue Req KY Division
MIP/VPP Accrual	1,498,907	5.20%	77,956	9.66%	7,528
Self Insurance Adjustment	2,915,283	5.20%	151,620	9.66%	14,641
Restricted Stock Grant Plan	4,631,448	5.20%	240,876	9.66%	23,260
Restricted Stock MIP	12,632,356	5.20%	656,993	9.66%	63,443
Charitable Contribution Carryover	11,032,917	5.20%	573,808	9.66%	55,410
VA Charitable Contribution Carryover	(9,275,764)	5.20%	(482,421)	9.66%	(46,585)
Total Division 002	23,435,147		1,218,833		117,697

Division 012 Balances as Filed in Account 190 ADIT (Positive Value = Debit Balance)

	DTA	As-Filed Jurisdictional Allocator	DTA Allocation to KY Division	Grossed-Up Rate of Return Using 21% Fed	DTA Revenue Req KY Division
MIP/VPP Accrual	(574,777)	5.67%	(32,593)	9.66%	(3,147)
Total Division 002	(574,777)		(32,593)		(3,147)

Division 091 Balances as Filed in Account 190 ADIT (Positive Value = Debit Balance)

	DTA	As-Filed Jurisdictional Allocator	DTA Allocation to KY Division	Grossed-Up Rate of Return Using 21% Fed	DTA Revenue Req KY Division
MIP/VPP Accrual	(17,997)	50.25%	(9,043)	9.66%	(873)
Reg Asset Benefit Accrual	157,983	50.25%	79,386	9.66%	7,666
Total Division 091	139,986		70,343		6,793

Division 009 Balances as Filed in Account 190 ADIT (Positive Value = Debit Balance)

	DTA	As-Filed Jurisdictional Allocator	DTA Allocation to KY Division	Grossed-Up Rate of Return Using 21% Fed	DTA Revenue Req KY Division
MIP/VPP Accrual	(18,182)	100.00%	(18,182)	9.66%	(1,756)
Total Division 091	(18,182)		(18,182)		(1,756)

Total First Category Reduction to Revenue Requirement Related to Account 190 ADIT $ (119,587)

Q. Have you quantified the effects on the revenue requirement of subtracting the temporary differences for the DTAs in the second category from rate base?

A. Yes. The effects for each temporary difference and in total are summarized in the following table.[15]

[15] *Id.*

Atmos Energy Corporation - Kentucky Division						
AG Recommendation to Subtract Temporary Difference Associated with Certain DTAs						
KPSC Case No. 2017-00349						
Test Year Ended March 31, 2019						
$						
See Responses to AG 1-33, 1-34, 1-35						
Division 002 Balances as Filed in Account 190 ADIT (Positive Value = Debit Balance)						
	DTA	Temporary Difference 38.9% Tax Rate	As-Filed Jurisdictional Allocator	DTA Allocation to KY Division	Grossed-Up Rate of Return Using 21% Fed	Temp Diff Revenue Req KY Division
SEBP Adjustment	26,316,340	67,651,260	5.20%	3,518,457	9.66%	339,761
Rabbi Trust	1,442,452	3,708,103	5.20%	192,854	9.66%	18,623
Director's Stock Awards	5,939,395	15,268,368	5.20%	794,089	9.66%	76,681
Total Division 002	33,698,187	86,627,730		4,505,400		435,066
Division 091 Balances as Filed in Account 190 ADIT (Positive Value = Debit Balance)						
	DTA	Temporary Difference 38.9% Tax Rate	As-Filed Jurisdictional Allocator	DTA Allocation to KY Division	Grossed-Up Rate of Return Using 21% Fed	DTA Revenue Req KY Division
SEBP Adjustment	1,389,076	3,570,889	50.25%	1,794,372	9.66%	173,274
Total Second Category Reduction to Revenue Requirement Related to Account 190 ADIT						$ (608,340)

C. The DTA Due to The NOL Temporary Difference Should Be Excluded from Rate Base

Q. Please describe the DTA due to the NOL carryforward temporary difference.

A. The Company allocated $751.240 million of the Atmos general office division (002) DTA due to the NOL carryforward (DTA – NOL) temporary difference to the Kentucky jurisdiction and added it to rate base. That allocation increases the Kentucky jurisdictional rate base and offsets the DTL due to accelerated and bonus tax depreciation that otherwise would be subtracted from rate base. This DTA increases the

Company's revenue requirement by $3.742 million.[16]

Q. Please describe the origination of the DTA – NOL.

A. The Atmos DTA – NOL is calculated by the Company based on its actual consolidated taxable income, which it separates into regulated utility taxable income and unregulated affiliate taxable income. Atmos utilizes a fiscal year ending September 30 for financial reporting and for income tax purposes. For each fiscal year, Atmos calculates its taxable income on a consolidated basis, including both income and deductions for the regulated and unregulated segments and determines whether there is a taxable loss. If there is a loss, Atmos can carry it back against taxable income in the three prior fiscal years. If there is any remaining loss, then it can carryforward that loss and apply it against taxable income in future fiscal years. The DTAs, both federal and state, are calculated by multiplying the federal and state income tax rates times the NOL carryforward temporary difference. In future years, the DTAs are reduced as the carryforwards are used or are increased if there are additional taxable losses.

Atmos repeats this process for the regulated and unregulated segments. In recent years, the regulated utility segment has a carryforward loss, but the unregulated segment

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

has had income in those same fiscal years. That means that Atmos allocates a greater DTA – NOL to the regulated segment than actually exists on its consolidated books.

Q. Please describe how the accounting works when there is a taxable loss and carryforward, particularly the interrelationship between the current income tax expense, deferred tax expense, and the DTA – NOL.

A. In years in which there is a taxable loss that cannot be carried back, the utility credits (reduces) deferred income tax expense for the tax effect of the loss, which reduces the deferred income tax expense and total income tax expense, and defers the reduction in income tax expense through a debit (increase) to the DTA – NOL in account 190. If the next year results in another taxable loss, then this process is repeated and the DTA – NOL in account 190 grows. If, however, the next year results in taxable income, then there is a reduction in taxable income in that year by the amount of the carryforward that is used, thus reducing the current income tax expense. This is offset by an increase in deferred income tax expense and a credit (reduction) to the DTA – NOL.

Q. Did the Company correctly describe this interrelationship in its Request for PLR?

A. Yes. The Company provided a copy of its Request for PLR as Exhibit PM-1 attached to Atmos witness Mr. Pace McDonald's Direct Testimony in Case No. 2015-00343. In that Request for PLR, the Company assumed pretax book income of $1,000, temporary differences due to accelerated tax depreciation of $2,500, a net operating loss of $1,500 ($1,000 less $2,500), no ability to carryback the loss, and an income tax rate of 35%.

In the resulting accounting entries, the Company shows $0 in current income tax expense and deferred income tax expense resulting from the temporary difference from accelerated tax depreciation of $875 ($2,500 times 35%), for a combined $875 in total income tax expense *before* consideration of the NOL. However, the loss results in a credit (reduction) to deferred income tax expense of $525 ($1,500 times 35%) and a DTA – NOL of $525, for a combined $350 in total income tax expense *after* consideration of the NOL ($875 less $525).

Q. Does that mean that combined income tax *expense* (current income tax expense and deferred income tax expense) is reduced in the year of the taxable loss?

A. Yes. The reduction of $525 in combined income tax *expense* was deferred as a DTA – NOL in account 190.

Q. Has that reduction in income tax *expense* ever been reflected in the Atmos revenue requirement?

A. No. The Commission has never reduced the income tax expense included in the Atmos revenue requirement to reflect the reduction due to a net operating loss.

Q. Can you demonstrate that?

A. Yes. The Commission uses a formula methodology to calculate combined income tax expense that is based on pretax book income before the per books interest expense, less the synchronized interest expense, times the income tax rate. In the calculation of income tax expense, the Commission does not distinguish between current income tax expense and deferred income tax expense. The Commission does not and has not reduced this combined income tax expense for the effects of any credit to deferred income tax expense for net operating loss carryforwards.

This methodology and the results can be seen on the Company's filing Schedule E in this case.[17] For the test year, the Company shows jurisdictional "operating income before income tax & interest" of $37.778 million, which ties to Schedule C-2. It then calculates "taxable income" by subtracting the "interest deduction" of $9.960 million, which is the synchronized interest based on the weighted average cost of debt times the Company's proposed jurisdictional rate base. The calculation of synchronized interest is shown on the lower part of this schedule.

In the final step, the Company calculates federal and state income tax expense by multiplying taxable income of $27.818 million times the combined federal and state income tax rate of 38.9%. The calculated federal and state income tax expense is

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[17] I have attached a copy of Schedule E as my Exhibit___(LK-5) for ease of reference.

$10.821 million. It should be noted that the $10.821 million shown on Schedule E is the income tax before the proposed rate increase. The Company adds another $4.003 million to reflect the income tax expense on its requested rate increase, and included a total of $14.824 million in federal and state income tax expense in the revenue requirement.[18]

Q. If Atmos recovers income tax expense with no reduction for the effects of an NOL in the revenue requirement, then is it reasonable for customers to pay a return on the DTA – NOL when they already have paid for the expense in the revenue requirement?

A. No. The Company's proposal is grossly inequitable and would impose an unreasonable and unjustified cost on customers. Atmos already recovers its full income tax expense from customers in the revenue requirement. To the extent that the Company did not actually pay that expense due to an NOL and instead deferred the cash savings in the DTA – NOL, there is a benefit (avoided financing costs) that accrues to the Company and solely to the Company. Customers should not have to pay a carrying charge on income tax expense that they already have paid through the revenue requirement, but that the Company has been able to retain through deferred payments to the federal and

[18] Refer to Schedule B-5F. I have attached a copy of Schedule B-5F from the Company's filing as my Exhibit___(LK-6) for ease of reference.

state governments. The Company is economically made whole without including the DTA – NOL in the rate base.

Q. Do the normalization requirements set forth in the Internal Revenue Code of 1986 ("IRC") require that the Commission include the DTA – NOL in rate base or risk losing the DTL benefits of accelerated tax depreciation?

A. No. In addition to the IRC itself, the IRS provides guidance to taxpayers through PLRs. PLR 2014-18024 provides the most recent and most directly relevant guidance to the Commission, including Atmos, even though this is not the PLR requested by Atmos. The Request for PLR and the PLR obtained by Atmos are fundamentally flawed and cannot be relied on because they do not accurately reflect the fact that the Commission does not and has not reduced income tax expense for the credit to deferred income tax expense resulting from the NOL.

The facts set forth in PLR 2014-18024 are identical to the facts before the Commission in this proceeding, except that the regulator in that case declined to include the DTA – NOL in rate base because it claimed that it included the entire income tax expense in the revenue requirement without reduction for the NOL. The utility disagreed with the regulator in that case and sought a PLR to buttress its arguments. However, in that PLR, the IRS decided against the utility and in favor of the Commission. The IRS determined that if the Commission did not reduce income tax expense for the NOL, then it was not required to include the DTA – NOL in rate base. Alternatively, the IRS determined that if the Commission reflected the reduction in income tax expense for the NOL, then it must include the DTA – NOL in rate base.

In short, there is no normalization violation if the Commission does not reflect the NOL in income tax expense and does not include the DTA – NOL in rate base, or if the Commission reflects the NOL in income tax expense and includes the DTA – NOL in rate base. This PLR reflects a logical outcome and is consistent with the economics of the ratemaking process that I previously described.

PLR 2014-18024 states:

> Commission has stated that, in setting rates it includes a provision for deferred tax based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has an NOLC or MTCC. Such a provision allows a utility to collect amounts from ratepayers equal to income taxes that would have been due absent the NOLC and MTCC. Thus, Commission has already taken the NOLC and MTCC into account in setting rates.
>
> ***
>
> Both Commission and Taxpayer have intended, at all relevant times, to comply with the normalization requirements. Commission has stated that, in setting rates it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has an NOLC or MTCC. Such a provision allows a utility to collect amounts from ratepayers equal to income taxes that would have been due absent the NOLC and MTCC. Thus, Commission has already taken the NOLC and MTCC into account in setting rates. Because the NOLC and MTCC have been taken into account, Commission's decision to not reduce the amount of the reserve for deferred taxes by these amounts does not result in the amount of that

> reserve for the period being used in determining the taxpayer's expense in computing cost of service exceeding the proper amount of the reserve and violate the normalization requirements. We therefore conclude that the reduction of Taxpayer's rate base by the full amount of its ADIT account without regard to the balances in its NOLC-related account and its MTCC-related account was consistent with the requirements of §1.167(I)-1 of the Income Tax regulations.

Q. Is the income tax expense included in the revenue requirement by the Commission in the Atmos rate proceedings calculated in the same manner as that described by the IRS for the other utility in PLR 2014-18024?

A. Yes. The income tax expense "in setting rates . . . includes a provision for deferred tax based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has an NOLC or MTCC." Such a provision allows a utility to collect amounts from "ratepayers equal to income taxes that would have been due absent the NOLC and MTCC."

It should be noted that the methodology used by the Commission incorporates the effects of all temporary differences, thus netting DTAs and DTLs, and does not specifically calculate the current income tax expense or deferred tax expense for each temporary difference. It nevertheless, through the formula methodology, includes the provision for deferred tax based on the entire difference between accelerated tax and regulatory depreciation.

Q. At the Commission's direction in Case No. 2013-00148, Atmos sought and obtained a PLR that Atmos argued in Case No. 2015-00343 now requires the Commission to include the DTA – NOL in rate base even though the Commission also includes income tax expense in the revenue requirement with no reduction for the NOL. Please respond.

A. Unfortunately, the Atmos Request for PLR includes a factual inaccuracy that renders it inapplicable and irrelevant. In its Request for PLR, Atmos incorrectly claims that the Commission's ratemaking for income tax expense is *different* than the ratemaking for the utility in PLR 2014-18024 and argues that the IRS determination in PLR 2014-18024 was inapplicable to Atmos specifically for that reason.[19]

In its Request, Atmos states: "The type of ratemaking for the DTA claimed by the regulators in PLR 201418924 is not practiced (or even claimed to be practiced) by the regulators in Kentucky."[20] In the prior proceeding, when the AG asked the Company to support that critical factual claim in its Request for PLR, the Company asserted (incorrectly) that the Commission had reduced the deferred income tax expense for the NOL credit.[21] The Company stated in its response:

> In setting the provision (or tax expense) for deferred taxes in the case, the Commission in PLR 201418024 took into account the entire difference between accelerated tax and regulatory depreciation. It did not adjust the deferred tax

[19] Exhibit PM-1 attached to Mr. McDonald's Direct Testimony in Case No. 2015-0343.
[20] *Id.*
[21] Atmos response to AG 1-22 in Case No. 2015-00343.

provision for the establishment of an NOLC DTA.

Unlike PLR 201418024, the provision for deferred taxes in KPSC 2013-00148 was impacted by both the entire difference between accelerated tax and regulatory depreciation AND the recording of an NOLC DTA. If the Company's NOLs had been excluded from the deferred tax provision, the Company's provision for income taxes would have been higher than [the] tax provision included in the filing.[22]

In addition, in Case No. 2015-00343, the AG asked the Company to:

Please confirm that the KPSC reflected full income tax normalization in the income tax expense allowed in Case No. 2013-00148, meaning that it included the deferred income tax expense debit related to accelerated tax depreciation with no reduction for any deferred income tax expense credit related to an NOL. Cite to the Order and all other record evidence that supports your response.

The Company responded:

The Company did reflect full income tax normalization but the meaning of full income tax normalization as described in the question is incorrect. Full income tax normalization would result in a provision for income taxes which includes the debit (increase) related to accelerated tax depreciation AND a credit (decrease) related to the recording of an NOL. While not specifically addressed in the order, the deferred income tax expense in KPSC Case No. 2013-00148 was calculated in this manner.[23]

The Company's assertion made in the Request for PLR and repeated in the Company's responses to AG discovery simply is incorrect. In Case No. 2015-00343, the AG subsequently asked the Company to identify where in its filing in Case No. 2013-

[22] *Id.*

[23] *Id.*

00148 or in the Commission's Order in that proceeding and where in the Case No. 2015-00343 proceeding there was any reduction in income tax expense for the NOL credit. In response, the Company asserted that it had been reflected, but failed to identify any such specific adjustment.[24]

This is a critical factual issue. The Company's Request for PLR had it wrong. The Company's initial responses to AG discovery in Case No. 2015-00343 had it wrong. There is no reduction in income tax expense for the NOL credit. Simply claiming that there is does not make it so.

The IRS relied on the accuracy of the Company's representation and repeated it in the PLR as follows:

> Taxpayer maintains an ADIT account. In addition, Taxpayer maintains an offsetting series of entries - a "deferred tax asset" and a "deferred tax expense" - that reflect that portion of those 'tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an NOLC.

The PLR itself states:

> This ruling is based on the representations submitted by the Taxpayer and is only valid if those representations are accurate. The accuracy of these representations is subject to verification on audit.

[24] Response to AG 2-1 in Case No. 2015-00343.

Thus, the critical factual error renders the Atmos PLR inapplicable and irrelevant. The Commission is not required to include the DTA – NOL in rate base to avoid a normalization violation.

Alternatively, the Commission is not required to provide the Company recovery of income tax expense without reduction for the NOL credit if it includes the DTA – NOL in rate base.

Q. Does the impact of these two alternatives vary significantly?

A. Yes. If the Commission excludes the DTA – NOL from rate base, it results in a significant reduction in the revenue requirement, but the reduction is less than the effect of eliminating or reducing the income tax expense, which is comprised solely of deferred income tax expense and the $0 in current income tax expense.

Q. What is your recommendation?

A. I recommend that the Commission exclude the DTA – NOL from the Company's rate base. Alternatively, the Commission should reduce income tax expense to reflect the NOL credit. Either approach is consistent with the IRC normalization requirements.

<u>D. Cash Working Capital is Overstated and Should be Reduced to Reflect the Corrected Results of The Lead/Lag Study</u>

Q. Please 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 $3.271 million based on the one-eighth O&M expense methodology.

Q. Is this methodology reasonable?

A. No. It is outdated, inaccurate, and arbitrary. The methodology is simple, but it does not reflect the actual leads and lags in the Company's operating cash flows. Only the lead/lag study approach accurately measures these leads and lags and calculates the actual average investment by either the Company's customers or its investors during the test year.

Q. Did the Company provide a cash working capital study based on the lead/lag approach in response to the Commission Order in Case No. 2015-00343?

A. Yes. The Company provided a lead/lag study and calculated a cash working capital investment of $2.400 million.[25]

Q. Was the lead/lag study performed correctly?

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[25] Schedule ATO CWC1 A. I have attached a copy of the summary schedule from the study as my Exhibit___(LK-7).

A. No. The correct calculation results in a *negative* $3.553 million cash working capital investment, not the positive $2.400 million investment claimed by the Company. The Company incorrectly included $5.953 million of non-cash expenses in the calculation of the cash working capital investment, including deferred federal income tax expense ($1.087 million), deferred state income tax expense ($0.069 million), depreciation expense ($2.307 million), and return on equity ($2.490 million).

Q. Is a negative cash working capital investment for the Kentucky division consistent with the results of other Atmos Energy Corporation lead/lag studies filed in other jurisdictions correctly calculated to exclude non-cash expenses?

A. Yes. Atmos performed and filed lead/lag studies in rate cases before the Colorado Public Utilities Commission, Tennessee Regulatory Authority, Railroad Commission of Texas, and Virginia State Corporation Commission.[26]

In Colorado Docket No. 13AL-0496G (2012), Atmos filed a working capital analysis with $77.668 million in operating expenses and *negative* $2.773 million cash working capital. In Colorado Docket No. 14AL-0300G (2013), Atmos filed a working capital analysis with $103.090 million in operating expenses and *negative* $3.836 million in cash working capital. In Colorado Docket No. 15AL-0299G (2014), Atmos

[26] Atmos provided summaries of the results of these studies filed in its other jurisdictions in response to AG 1-10 in Case No. 2015-00343 and in response to AG 1-30 in this proceeding.

filed a working capital analysis with $105.723 million in operating expenses and *negative* $2.578 million in cash working capital.

In Tennessee Docket No. 12-00064 (2012), Atmos-Tennessee filed a working capital analysis with $127.490 million in operating expenses and $0.607 million in cash working capital, although that study erroneously included amounts for non-cash depreciation and return on equity. When these non-cash amounts are removed, the study reflects *negative* $1.523 million in cash working capital. In Tennessee Docket No. 12-00064 (2013), Atmos-Tennessee filed a working capital analysis with $132.984 million in operating expenses and $0.653 million in cash working capital, although that study erroneously included amounts for non-cash depreciation and return on equity. When these non-cash amounts are removed, the study reflects *negative* $1.583 million in cash working capital.

In Tennessee Docket No. 14-00146 (2014), Atmos-Tennessee filed a working capital analysis with $154.097 million in operating expenses and $1.211 million in cash working capital, although that study erroneously included amounts for non-cash depreciation and return on equity. When these non-cash amounts are removed, the study reflects *negative* $1.319 million in cash working capital. In Tennessee Docket No. 14-00146 (2016), Atmos-Tennessee filed a working capital analysis with $158.493 million in operating expenses and $0.956 million in cash working capital, although that study erroneously included amounts for non-cash depreciation and return on equity. When these non-cash amounts are removed, the study reflects *negative* $1.875 million in cash working capital.

In Texas Docket No. 10174 (2012), Atmos Mid-Tex filed a working capital analysis with $179.219 million in operating expenses and *negative* $1.957 million in cash working capital. In Statement of Intent in Texas (2013), Atmos Mid-Tex filed a working capital analysis with $173.655 million in operating expenses and *negative* $2.757 million in cash working capital.

In Virginia Docket No. PUE-2015-00119, Atmos Virginia filed a working capital analysis with *negative* $0.168 million in cash working capital, although that study erroneously included amounts for non-cash depreciation and deferred income taxes. When these amounts are removed, the study reflects *negative* $0.358 million in cash working capital.

The point of this recitation of Atmos' working capital studies filed in other jurisdictions is to demonstrate the point that in *every* instance, when correctly calculated using the lead/lag study approach, Atmos had *negative* cash working capital.

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 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.

Q. Atmos witness Mr. Christian argues that the cash working capital should include the return on equity at a 0 days expense lag. Is this correct?

A. No. First, the return on equity is a non-cash expense, except for the dividend component reflected in the discounted cash flow ("DCF") model. The DCF model, used by both Company witness Vander Weide and AG witness Mr. Baudino, is comprised of both the dividend return and projected growth in the stock price. Atmos pays dividends quarterly. For that component of the return on equity, if the Commission's return on equity could be mechanically separated into the dividend component and the growth component, an expense lag of 45 days would be required, not the 0 days asserted by Mr. Christian. The growth component is an annual projection. For that component of the return on equity, an expense lag of 182.5 days would be required, not the 0 days asserted by Mr. Christian. Thus, if the return on equity is included in the cash working capital study, it would be even more negative than simply excluding this non-cash expense, not more positive.

Q. If the Commission adopts your recommendation to use the lead/lag approach to calculate cash working capital in lieu of the one-eighth formula methodology, is there another adjustment to rate base required?

A. Yes. The prepayments need to be removed from rate base, an adjustment with which the Company agrees.[27] This additional adjustment is necessary because the lead/lag approach to cash working capital already includes the effects of prepayments.

Q. What is your recommendation?

A. I recommend that the Commission set the Company's cash working capital at negative $3.553 million based on the lead/lag study filed by the Company adjusted to remove the non-cash expenses. This is a reduction of $6.823 million compared to the Company's proposed cash working capital of $3.271 based on the one-eighth O&M expense methodology.

The lead/lag study approach properly measures the timing of cash receipts for revenues or cash disbursements for expenses, and thus, the investment required by investors or customers. The lead/lag study approach is more accurate and the Company incurred no incremental costs for the study.[28] In contrast, the one-eighth of O&M expense methodology is outdated and inaccurate. The one-eighth of O&M expense

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[27] Direct Testimony of Joe T. Christian at 15-16.
[28] Company's response to AG 1-31, which states: "There are no incremental costs associated with the

methodology fails to measure the timing of cash receipts for revenues or cash disbursements for expenses. It is based on a simplistic formula that may have been appropriate when adopted by the FERC in the early 20th century, but is no longer appropriate given the availability of data and the ability of computer-based calculations. Finally, all the Company's lead/lag studies in other jurisdictions demonstrate unequivocally that a correctly calculated cash working capital study results in negative cash working capital, meaning that customers provide the Company with capital to fund other rate base investments.

Q. Have you quantified the effect of your recommendation?

A. Yes. The effect is to reduce the revenue requirement by $0.826 million using the Company's proposed return on rate base and the new income tax rate of 21% reflected in the Company's filing. This includes the effect on rate base of using the corrected cash working capital study results and removing the prepayments to avoid double counting the rate base effects.

E. The Proposed Regulatory Asset for Rate Case Expense Should Be Disallowed

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Study." I have attached a copy of the Company's response to AG 1-31 as my Exhibit___(LK-8).

Q. Please describe the Company's request for recovery of rate case expenses due to this proceeding.

A. The Company projects that it will incur $0.314 million in rate case expenses in this proceeding. It included $0.235 million in rate base (based on a 13-month average) and proposed a two-year amortization, or $0.157 million in amortization expense.

Q. Should the Commission authorize recovery of these expenses?

A. No. This case never should have been filed and rate case expenses of this magnitude never should have been incurred for filing a case based on forecast costs that are unreasonable and unrealistic. The Commission should make this point by denying any recovery of these costs.

The requested rate increase is driven by an excessive return on equity; failure to include the annualized effect of new debt issued to replace a maturing long term debt issue at less than half the interest rate of the old debt; unreasonable and unrealistic increases in forecast gross plant additions; failure to make appropriate ratemaking adjustments to reduce rate base for various income tax-related costs (unrelated to the federal income tax rate reduction); failure to use a reasonable calculation of cash working capital; unreasonable and unrealistic increases in forecast O&M expenses compared to actual expenses; failure to remove all incentive and stock-based compensation expense; failure to remove excessive retirement plan expenses; and unreasonable and unrealistic increases in forecast ad valorem tax expense compared to actual expenses; among others.

III. OPERATING INCOME ISSUES

A. Forecast Kentucky Division Operation and Maintenance Expense Is Excessive and Should Be Reduced

Q. Have you reviewed the Company's forecast O&M expense for the Kentucky division?

A. Yes. I reviewed the Company's forecast O&M expense for the Kentucky division by category (referred to by the Company as "cost element") and FERC account to identify unusual increases compared to actual expense levels incurred in prior years.[29] I then followed up with additional AG discovery to obtain historic data at the same level of category and FERC account detail and to obtain variance analyses at the category level.

Q. Did you identify unusual increases in the forecast O&M expense compared to historic actual expense levels in any category and/or FERC accounts?

A. Yes. The Company seeks significant increases in certain categories of forecast O&M expense compared to actual O&M expense in 2016, the most recent year for which

[29] Company's workpaper "OM_for_KY-2017_case" and, more specifically, the sheet "Div 9 forecast" in

actual information is available. More specifically, the Company seeks increases in vehicles and equipment expense of $0.195 million, to $1.018 million from $0.823 million; and outside services of $0.368 million, to $2.971 million from $2.603 million (after excluding one-time expense of $0.847 in nonrecurring settlement expense).[30]

Q. Have you reviewed the Company's rationale for the increases in these expenses?

A. Yes. The Company states that the "primary driver" for the increase in vehicles and equipment expense is "the replacement of leased vehicles." The Company provided no further support for this increase in forecast expense. The Company provided no rationale for the increase in outside services expense other than to explain that the expense in 2016 included $0.847 million in settlement expense.[31]

Q. What is your recommendation?

A. I recommend that the Commission remove the forecast increases in these specific expense categories. The Company has not justified these increases. The Commission should assess the Company's forecast expenses with a healthy skepticism and compare the forecast expenses to recent actual expenses to determine whether the forecast

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that workpaper provided in response to Staff 1-71.

[30] Company's response to AG 1-22, Attachment 2 Part B. I have attached a copy of the relevant pages of the response to AG 1-22 as my Exhibit___(LK-9).

[31] *Id.*

expenses are consistent with actual experience, and if not, whether the Company has sufficiently justified significant increases in the expenses. If not, then the increases should be disallowed.

B. Forecast Kentucky/Mid-States Division Operation and Maintenance Expense is Excessive and Should Be Reduced

Q. Have you reviewed the Company's forecast O&M expense for the Kentucky/Mid-States division?

A. Yes. I reviewed the Company's forecast O&M expense for the Kentucky/Mid-States division by category (referred to by the Company as "cost element") and FERC account to identify unusual increases compared to actual expense levels incurred in prior years.[32] I then followed up with additional AG discovery to obtain historic data at the same level of category and FERC account detail and to obtain variance analyses at the category level.

Q. Did you identify unusual increases in the forecast O&M expense compared to historic actual expense levels in any category and/or FERC accounts?

A. Yes. The Company seeks significant increases in certain categories of forecast O&M expense compared to actual O&M expense in 2016, the most recent year for which actual information is available. More specifically, the Company seeks increases in telecom expense of $0.104 million ($0.207 million times 50.25% Kentucky allocation) to $0.263 (Kentucky allocation) from $0.159 million (Kentucky allocation); travel and entertainment of $0.080 million (Kentucky allocation) to $0.292 million (Kentucky allocation) from $0.212 million (Kentucky allocation); and outside services of $0.648 million (Kentucky allocation), to $1.984 million (Kentucky allocation) from $1.336 million (Kentucky allocation).[33]

Q. Have you reviewed the Company's rationale for the increases in these expenses?

A. Yes. The Company states that the telecom expense increase is due to the fact that certain telecom expenses are budgeted at the Kentucky/MidStates division, but the actual expenses are coded to the specific rate division, in this case, Kentucky. However, the Company also forecasts an increase in telecom expenses for the Kentucky division.[34] Thus, there is no offset to the increase in the Kentucky/MidStates division with any reduction in the Kentucky division. In other words, the Company's rationale does not support significant increases in both the Kentucky/MidStates division and the Kentucky division.

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[32] Company's workpaper "OM_for_KY-2017_case" provided in response to Staff 1-71.

[33] Company's response to AG 1-23, Attachment 2 Part B. I used the Company's allocation factor of 50.25% to allocate all Kentucky/MidStates division expenses to the Kentucky jurisdiction reflected in the referenced response and also shown on Exhibit GKW-1 attached to Mr. Waller's Direct Testimony. I have attached a copy of the relevant pages of the response to AG 1-23 as my Exhibit___(LK-10).

The Company states that the travel and entertainment expense increase is due to increased travel compared to 2016. It also states that the increase is due to the fact that certain travel and entertainment expenses are budgeted at the Kentucky/MidStates division, but the actual expenses are coded to the specific rate division, in this case, Kentucky. However, the Company also forecasts an increase of $0.056 million in travel and entertainment expense (to $0.457 million from $0.401 million) for the Kentucky division. Thus, there is no offset to the increase in the Kentucky/MidStates division with any reduction in the Kentucky division. In other words, the Company's rationale does not support significant increases in the Kentucky/MidStates division when there also is an increase in the forecast expense for the Kentucky division.

The Company states that the outside services expense increase is due to the fact that certain telecom expenses are budgeted at the Kentucky/MidStates division, but the actual expenses are coded to the specific rate division, in this case, Kentucky. However, as I noted previously, the Company also forecasts a significant increase in outside services expenses for the Kentucky division. Thus, there is no offset to the increase in the Kentucky/MidStates division with any reduction in the Kentucky division. In other words, the Company's rationale does not support significant increases in both the Kentucky/MidStates division and the Kentucky division.[35]

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[34] Company's response to AG 1-22.
[35] *Id.*

Q. What is your recommendation?

A. I recommend that the Commission remove the forecast increases in these expense categories. The Company has not justified these increases. As I noted previously, the Commission should assess the Company's forecast expenses with a healthy skepticism and compare the forecast expenses to recent actual expenses to determine whether the forecast expenses are consistent with actual experience, and if not, whether the Company has sufficiently justified significant increases in the expenses. If not, then the increases should be disallowed.

C. Directors' Stock Expense Should Be Disallowed

Q. Describe the Company's requested Directors' stock expense.

A. The Company compensates its Directors in part through a deferred stock compensation plan. The Company included $0.345 million of these corporate general office division (002) expenses allocated to Kentucky.[36]

Q. Is stock expense inherently compensation tied to the performance of the Company's financial metrics, in this case, the stock price?

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[36] Company's response to AG 2-4. I have attached a copy of this response as my Exhibit___(LK-

A. Yes.

Q. What is your recommendation?

A. I recommend that the Commission exclude this expense from the revenue requirement in the same manner and for the same reasons that the Commission historically has excluded other incentive compensation tied to the financial performance of the utility or its parent company.

D. Retirement Plan Expense Is Excessive

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

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

> The Commission finds that, for ratemaking purposes, it is not reasonable to include both KU's Pre 2006 DDB plan contributions and KU's matching contributions to the 401(k) Plan for the following employee categories: exempt, manager, non-exempt, and officer and director personnel. Employees participating in the Pre 2006 DDB Plan enjoy generous retirement plan benefits, making the matching 401(k) Plan amounts excessive for ratemaking purposes.

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11).

> Accordingly, the Commission denies for recovery 401(k) Plan matching contributions in the amount of $1,720,383 before gross-up.[37]

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

> The Commission believes all employees should have a retirement benefit, but finds it excessive and not reasonable that Cumberland Valley continues to contribute to both a defined benefit pension plan as well as a 401(k) plan for salaried employees. The Commission will allow Cumberland Valley to recover only the costs of the more expensive defined benefit plan for the salaried employees and the 401(k) plan for union employees. Accordingly, the Commission will remove for ratemaking purposes Cumberland Valley's test year 401(k) contributions for salaried employees.[38]

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

A. The effect is a reduction in retirement plan expense of $0.575 million and a reduction in the revenue requirement of $0.579 million. This includes the retirement plan expense incurred directly by the Kentucky rate division and the expense allocated to Kentucky for ratemaking purposes from the SSU and Kentucky/Midstates divisions for their employees.[39]

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

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

[39] Company's public responses to Staff 1-65, 2-24, 3-11, and AG 2-25. I have attached a copy of these responses as my Exhibit___(LK-12). It should be noted that the Company did not provide the test year amount of these expenses and indicated that it could not do so. Consequently, I used the annualized actual expenses from January 2017 through August 2017 that were provided in Confidential response to Staff 2-24. My calculations are detailed on my Confidential electronic workpapers filed along with my Direct Testimony in this proceeding.

<u>E. Forecast Income Tax Expense Should Be Reduced to Reflect New Federal Corporate Income Tax Rate of 21%</u>

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

A. In late 2017, President Trump signed legislation that reduced the federal corporate income tax rate from 35% to 21% effective January 1, 2018.

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

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

In addition, there are three similar indirect effects from affiliate charges that include an income tax component (based on an equity return applied to "rate base" and an ADIT component used to calculate rate base). These effects primarily are included in charges to the Kentucky Division for ratemaking purposes from SSU Divisions 002 and 012 and Kentucky/MidStates Division 091.

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

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

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

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

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

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

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

A. Yes. The reduction in the base revenue requirement is $9.731 million. This consists of the reduction of $6.796 million in the revenue requirement due to the reduction in federal income tax expense and a reduction of $2.935 million in the revenue requirement due to the amortization of the excess ADIT of $46.372 million.[40]

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

A. Yes.

Q. Should the Commission also reflect the income tax rate of 21% in the revenue

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

requirement for all riders where there is an equity return and income tax expense?

A. Yes. That would include the present PRP rider if it is not terminated and the proposed ARM if it is adopted in this proceeding as well as any other present and/or future riders that include an income tax expense component.

F. Forecast Ad Valorem Tax Expense Is Excessive and Should Be Reduced

Q. Describe the Company's forecast of ad valorem tax expense.

A. The Company forecasts $5.073 million in ad valorem tax expense. The Company provided its calculation of the forecast expense in response to AG discovery.[41] The Company took its "estimated" ad valorem tax expense for 2017 and escalated it by 8% to forecast the 2018 expense, which it used for the test year expense.[42]

Q. Is this forecast ad valorem tax expense reasonable?

A. No. It is excessive and unjustified. The Company's actual ad valorem expense has declined over the most recent fiscal years while its plant balances have continued to increase. The Company actually incurred ad valorem expense of $5.721 million in fiscal year 2015, $5.127 million in fiscal year 2016, and $4.534 million in fiscal year 2017,

[41] Attachment 3 to the Company's response to AG 1-24. I have attached a copy of the entire response as my Exhibit___(LK-13), including the public non-confidential attachments.

[42] Attachment 1 to the Company's response to AG 1-24.

including allocations from the Kentucky/Midstates and the SSU Divisions for ratemaking purposes.[43] The Company's net plant balances were $459.421 million at December 31, 2014, $506.208 million at December 31, 2015, $553.636 million at December 31, 2016, and $604.160 million at September 30, 2017, including allocations from the Kentucky/Midstates and SSU Divisions for ratemaking purposes.[44]

Q. What is the Company's rationale for its forecast ad valorem tax expense?

A. The Company provided the following rationale in response to AG discovery.[45]

> A standard estimated tax increase from year to year is 8%. The 8% adjustment, based upon a 3% tax rate and 5% valuation increase, is used as an estimate of year over year tax projections. Without additional knowledge of projected final valuations, Atmos Energy utilizes the 8% increase in many of our service areas (states). Since Kentucky historically has issued final assessments later in the year, we utilize an 8% increase in taxes until we have a better understanding of the potential increase to valuation and tax rates.

Q. Does this rationale adequately justify the Company's forecast ad valorem tax expense?

A. No. It merely describes the Company's calculation for budget purposes. It does not justify the requested expense for ratemaking purposes, especially when compared to the Company's actual ad valorem tax expense and historic growth.

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[43] Attachment 3 to the Company's response to AG 1-24.
[44] Attachment 4 to the Company's response to AG 1-24.
[45] Company's response to AG 2-7. I have attached a copy of this response as my Exhibit___(LK-14).

Q. What is your recommendation?

A. I recommend that the Commission reject the Company's forecast ad valorem tax expense and instead adopt a forecast based on the most recent historic experience using the actual expense for the fiscal year ending September 30, 2017.

Q. What is the effect of your recommendation?

A. The effect is a reduction in forecast ad valorem tax expense of $0.539 million and in the revenue requirement of $0.543 million. I used a forecast expense of $4.534 million, which is the actual expense for the fiscal year ending September 30, 2017. I did not assume a continuation of the ad valorem expense downward trend for the last several years, nor did I assume that there would be any increase in the expense.

G. Amortization Expense for Rate Case Expenses Should Be Disallowed

Q. Did you address this issue in the Rate Base Issues section of your testimony?

A. Yes. I reflect the reduction in amortization expense and the revenue requirement on the table in the Summary section of my testimony.

H. Amortization Expense for Deferred Interest Should Be Included

Q. Describe the AG's recommendation to annualize the effect of the forecast new debt issuance in March 2019.

A. The AG's recommendation is described by AG witness Mr. Baudino. He recommends that the 4.0% cost of the new debt issue in March 2019 be included in the cost of debt and that the 8.5% cost of the maturing issue be excluded from the cost of debt in the calculation of the return on rate base. The Company did not annualize the reduction in the cost of debt; it included less than a half month of the savings in the calculation of the cost of debt.

I have reflected the annualized savings in the cost of debt included in the return on rate base. I describe the quantification of this savings in the Rate of Return Issues section of my testimony. However, even though the AG recommendation will result in the correct cost of debt at the end of the test year and going forward under the AG's recommendation, the Company will temporarily underrecover its cost of debt for a portion of the test year.

Q. What is your recommendation to address this temporary underrecovery for a portion of the test year?

A. I recommend that the Commission direct the Company to defer the differential in the interest expense between the maturing issue and the new debt issue and that it include an amortization expense in the revenue requirement. I recommend that the Commission use a ten-year amortization period for this purpose.

Q. What is the effect of your recommendation?

A. The effect is an increase in the revenue requirement of $0.136 million. This recommendation should be adopted only if the Commission adopts the AG's recommendation to annualize the cost of the new debt issue and remove the cost of the old debt issue.[46]

I. Depreciation Expense Should Be Reduced to Reflect Lower Capital Expenditures and Plant Additions

Q. Have you quantified the effect of your recommendation to reduce the Company's projected capital expenditures and plant additions addressed in the Rate Base Issues section of your testimony?

A. Yes. The effect is a reduction of $0.021 million in depreciation expense and the revenue requirement.[47] I reflect this amount on the table in the Summary section of my testimony.

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

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

J. Depreciation Expense Should Be Reduced to Reflect Lower Net Salvage Costs

Q. Describe net salvage and alternatives for recovery.

A. Net salvage refers to the cost of removal, less salvage income, to retire and remove an asset from service. Actual net salvage is always charged against (used to reduce) accumulated depreciation (if there is net negative salvage, where cost of removal exceeds salvage income) or to increase accumulated depreciation (if there is net salvage, where salvage income exceeds cost of removal).

Q. What are the recovery alternatives?

A. There are three approaches to reflect net salvage in depreciation rates. The first is to estimate and preemptively reflect future net salvage in the depreciation rates and expense. This is the approach reflected in the Company's present depreciation rates.[48] If there is net negative salvage (cost of removal), then the estimated future net salvage is added to the net book value to determine the amount that must be recovered, which then is divided by the average life for the assets to calculate the depreciation expense. This

[48] The present depreciation rates were adopted in Case No. 2015-00343 pursuant to a Stipulation, wherein the signatories agreed to the depreciation rates proposed by the Company in conjunction with the settlement of all issues in that case. The Stipulation does not apply to this current proceeding and the AG does not accept the continuation of those depreciation rates without modification in this proceeding. I have identified various concerns with those rates. However, I address only the net salvage approach reflected in those depreciation rates in this proceeding.

calculated depreciation expense is then divided by gross plant to calculate the depreciation rates. This approach results in greater depreciation rates in the earlier years of asset lives and lower depreciation rates in the latter years of asset lives compared to the second or third ways, all else equal.

The second approach is to include no estimate of future net salvage in depreciation rates. Instead, the net salvage is included in the depreciation rates and expense on a lagged basis. This occurs through the calculation of net book value, which reflects all actual net salvage in accumulated depreciation, but does not include any estimated future net salvage. This approach results in lower depreciation rates in the earlier years of asset lives and greater depreciation rates in the latter years of asset lives compared to the first or third approaches, all else equal.

The third approach is a compromise between the first and second approaches. The third approach includes net salvage at a level based on recent actual net salvage. In this manner, the third approach provides relatively contemporaneous recovery of actual net salvage rather than the preemptive recovery in the first approach or the lagged recovery of the second approach. This third approach results in lower depreciation rates in the earlier years of asset lives and greater depreciation rates in the latter years of asset lives compared to the first approach, and greater depreciation rates in the earlier years of asset lives and lower depreciation rates in the latter years of asset lives compared to the second approach, all else equal.

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

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

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

A. The depreciation rates adopted in Case No. 2015-00343 were based on the Company's proposed depreciation rates developed in a depreciation study filed in the proceeding. In those depreciation rates, the Company included net salvage based on forecasts of future cost of removal and salvage income, or the "first approach" that I previously described. The Company calculated historic net salvage divided by historic retirements and then applied this percentage to the entirety of each plant account.

For example, assume that the average actual annual retirements were $100,000 and the average actual annual net salvage was negative $20,000. Assume further that the plant balance in the account was $100 million, accumulated depreciation was $30 million, and the average service life was 30 years. Under the Company's "first approach" methodology, the net salvage would be negative 20%. This would be applied to the entire $100 million in the plant account to increase the depreciable, or recoverable, balance to $90 million (gross plant of $100 million plus $20 million net negative salvage less $30 million accumulated depreciation). The depreciation rate would be 3.00%, of which 2.33% is pure depreciation and 0.67% is interim net salvage. Depreciation expense would be $3 million, of which $2.333 million is pure depreciation and $0.667 million is net salvage.

Q. Is the Company's methodology appropriate?

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

Q. What is your recommendation?

A. I recommend the "third approach" methodology that I previously described. This methodology calculates the net salvage based on the same historic data used by the Company, but uses the average actual annual historic net salvage dollars divided by the gross plant in each plant account rather than by the average actual annual retirements.

This methodology assumes that the net salvage will continue at the same dollar amount until the next depreciation study. As such, it provides contemporaneous recovery of the net salvage dollars as I previously described.

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

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

A. The effect is a reduction in the revenue requirement of $3.430 million, comprised of the reduction in depreciation expense of $3.531 million (grossed-up from $3.507 million), offset by the return on the increase in capitalization of $0.101 million due to the reduction in accumulated depreciation.[49]

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

<u>K. Commitment and Banking Fees Should Be Included in Operating Expenses, Not In Cost of Short-Term Debt</u>

Q. Have you included the commitment and banking fees in operating expenses instead of in the cost of short-term debt?

A. Yes. In accordance with Mr. Baudino's recommendation, I have included $135,408 for these expenses in operating expenses. I made an offsetting adjustment to the revenue requirement for the reduction in short-term debt interest expense, which I address in the Rate of Return Issues section of my testimony.

Q. Is there another issue that is implicated by including the commitment and banking fees in operating expense instead of in the cost of short-term debt?

A. Yes. The Company presently includes the commitment and banking fees in the cost of short-term debt used for the capitalized financing costs (Allowance for Funds Used During Construction or "AFUDC") on construction work in progress ("CWIP").[50] Under the AG's recommendation, the entirety of the commitment and financing costs will be included in operating expenses. Accordingly, they should not be included in the cost of short-term debt used for AFUDC to avoid double counting and double recovery

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[50] Company's response to Staff 1-19. I have attached the narrative response to this request and an excerpt from Attachment 2 that shows the Company's calculation of the cost of short-term debt used for the AFUDC rate as Exhibit___(LK-15).

of the costs.

Q. What is your recommendation on this issue?

A. I recommend that the Commission direct the Company to exclude the commitment and banking fees from the cost of short-term debt used in the calculation of AFUDC on and after the date when rates are reset in this proceeding.

IV. RATE OF RETURN ISSUES

A. Quantification of AG's Recommendation for the Cost of Long Term Debt

Q. Have you quantified the effect of the AG's recommendation to modify the cost of long term debt from the cost proposed by the Company in its filing?

A. Yes. The AG's recommendation reduces the Company's revenue requirement by $1.089 million. Mr. Baudino recommends that the Commission include the 4.0% annualized cost of the new debt issue and exclude the 8.50% annualized cost of the maturing debt issue. As I noted in the Operating Income Issues section, the Commission should authorize the Company to defer the greater interest expense on the maturing debt issue for the first part of the test year and recover the deferred expense over a ten-year amortization period. The quantification in this section of my testimony is only for the reduction in the cost of debt.[51]

B. Quantification of AG's Recommendation for the Cost of Short Term Debt

Q. Have you quantified the effect of the AG's recommendation to modify the cost of short term debt from the cost proposed by the Company in its filing?

A. Yes. This recommendation reduces the cost of short-term debt to 0.92% from 1.99% and reduces the revenue requirement by $0.150 million, using the rate base adjusted for the AG recommendations that I addressed in the Rate Base Issues section of my testimony.[52] Mr. Baudino recommends that the commitment and banking fees be removed from the cost of short term debt and instead be included in operating expenses. I have reflected the effect of this recommendation on operating expenses in a separate adjustment and addressed the effect in the Operating Income Issues section of my testimony.

C. Quantification of AG's Recommendation for the Return on Equity

Q. Have you quantified the effect of the AG's recommendation for the return on common equity?

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

A. Yes. A return on equity of 8.8% reduces the Company's revenue requirement by $3.972 million. Each 1.0 percent in the return on equity in either direction affects the revenue requirement by $2.648 million. These amounts are incremental to the reductions in the revenue requirement for the AG's recommendations on the cost of long term debt and the cost of short term debt.[53]

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. The 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

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[52]*Id.*
[53]*Id.*

customers, and total O&M expense.[54] 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 10.35% and allocated costs from Division 002 to Division 091 using this factor. Atmos calculated a composite factor of 50.25% and allocated the Division 002 costs allocated to Division 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

[54] 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.

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 $0.740 million.[55]

VI. ANNUAL REVIEW MECHANISM

Q. Describe the Company's proposed Annual Review Mechanism.

A. The Company proposes that the Commission effectively abandon traditional general rate cases that are filed on an "as and when needed" basis and replace them with the proposed ARM, which will be "used to reset rates formulaically on an annual basis.[56] The ARM will allow the Company to increase base rates annually without the review, deliberation, and customer protections that characterize the traditional form of base ratemaking.

If the ARM is adopted, the Commission also will need to address the termination of the present PRP rider and modification of the DSM rider, although these issues were not addressed in the Company's Application or Direct Testimony. The Company responded to Staff discovery on these issues as follows:

> If the Commission were to approve the Company's proposed ARM, the Company would propose to adjust Sheet Nos. 34 and 35 to remove the DSM Lost Sales Adjustment (DLSA) from its Demand-Side Management Program and Sheet Nos. 38 and 39 to remove the Pipe Replacement Program (PRP) as the

[55] *Id.*
[56] Direct Testimony of Mark A. Martin at 6.

PRP rates would be rolled into the respective customer classes.[57]

Company witness Mr. Mark A. Martin generally describes the Company's request for the proposed ARM and the benefits that would accrue to the Company from adopting an ARM that would annually adjust base rates. Mr. Martin also claims that adopting an ARM will produce "benefits to the customer," although the only support that he offers for that claim is an assertion that the ARM annual rate reviews "will cost less."[58]

Company witness Mr. Greg Waller describes the Company's proposal in greater detail in his Direct Testimony and in his Exhibit GKW-3 wherein he provides a detailed template of the proposed ARM and the proposed ARM rider tariff.

Based on Mr. Waller's testimony and his Exhibit GKW-3, the Company will make annual ARM filings on or before December 1 of each year starting this year, with the increased rates effective on April 1 of the following year. The ARM filings will reflect forecast revenues and costs based on the Company's budget, inflation estimates, allocations from other divisions based on its Cost Allocation Manual ("CAM"), and other proposed calculations of revenues and costs using various specified ratemaking methodologies. The ARM will exclude promotional advertising expense and incentive compensation expense, but no other expenses. All other costs are recoverable and

[57] Company's response to Staff 2-1. I have attached a copy of this response as my Exhibit___(LK-16).

presumed reasonable. If the ARM is adopted, the Company will periodically file a depreciation study with the Commission and then use those depreciation rates to calculate depreciation expense in its next annual ARM filing. Revenues and certain costs will be subject to true-up based on actual costs. The Company will use the historic capital structure for the forecast rate of return, although this will be subject to the annual true-up, and the return on equity authorized in this proceeding.

Q. What is your recommendation?

A. I recommend that the Commission reject the proposed ARM for numerous reasons. First, the ARM is not necessary to achieve annual or even more frequent rate increases if the Company finds it necessary to seek increases that frequently. The Company already has the discretion and ability to make traditional general rate filings on an annual or more frequent basis.

Second, the ARM is not necessary to eliminate negative effects of regulatory lag, if any. The Company already has the discretion and ability to make traditional general rate case filings on an annual or more frequent basis and the ability to use a forecast test year as it has done in this proceeding and in prior proceedings.

Third, the ARM will harm customers by forcing them to incur more frequent and larger rate increases without the review and deliberation by the Commission inherent in

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[58] Direct Testimony of Mark A. Martin at 19-20.

the traditional general rate case process. The ARM provides no customer benefits, contrary to the Company's claim. This harm is due, in part, to the Company's ability to self-determine the scope and growth of forecast and actual capital expenditures, related operating expenses, and the scope and growth of other operating expenses, all with significantly reduced or no review or oversight by the Commission. It will harm customers by eliminating the procedural and behavioral protections inherent in the traditional general rate case process. The parties may or will have reduced discovery opportunities, no procedural opportunity to contest or seek to modify the Company's requests or methodologies from those set forth in Mr. Waller's Exhibit GKW-3, no procedural opportunity to brief issues to the Commission, no procedural opportunity for the adjudication of contested issues or to seek modification of the requests or methodologies, and no procedural opportunity to recommend different capital structures, cost of debt, or return on equity. In other words, the Company will have nearly free reign to incur and recover costs through continued increases in costs.

Fourth, the Company has provided no support for its sole claim of benefits to customers. The Company claims that the ARM will result in savings to customers through a reduction in costs incurred in the ratemaking process. The Company offered no evidence that this is true. Nevertheless, even if this claim is correct, it must be weighed against the cost to the customers of more frequent and larger rate increases than under the present traditional general rate case paradigm.

Finally, the ARM removes the behavioral incentives inherent in the traditional rate case paradigm and modifies the incentive to spend more in order to increase earnings. Under the traditional rate case paradigm, the utility has to exercise management control to maintain its authorized return between rate cases. This provides the behavioral incentive aligned with the utility's ratepayers, i.e., to limit capital expenditures and operating expenses, including ensuring that capital expenditures for efficiency gains are prioritized and that the savings actually are realized. In contrast, under the ARM, the utility does not have the same behavioral incentive; in fact, it is replaced with an incentive that rewards capital expenditures with greater earnings and allows recovery of all expenses. The ARM essentially guarantees the utility's authorized return at whatever level of capital expenditure or expense. This is precisely the wrong incentive from a ratemaking policy perspective.

Q. Is there any evidence that a rider, such as the ARM, is poor ratemaking policy?

A. Yes. The Commission need look no farther than the present PRP rider. The PRP rider can be viewed as a pilot program for the ARM and the results are not good. The Company has a history of overspending and underachieving compared to the PRP capital spending and miles of pipeline replaced estimates that it provided the Commission little more than six years ago and that the Commission relied on for approval of the PRP and the PRP rider. The Company has aggressively included costs in the PRP and aggressively increased its capital expenditures to the point where approximately half its expenditures are now identified as PRP and recovered through the PRP rider until the costs are rolled into base rates. In fact, the Company's own projections of PRP capital expenditures indicate that these expenditures will more than double its entire rate base in the next eight years.[59] This is in addition to its non-PRP capital expenditures, which at roughly the same level as the PRP expenditures, will compound the effects of the PRP capital expenditures. Together, the PRP and non-PRP capital expenditures will nearly double the Company's entire rate base in the next four years. This is *incomprehensible* for a utility that has almost no customer growth.

Q. Provide a history comparing the Company's projected to its actual PRP capital expenditures and pipeline replacement miles.

A. In Case No. 2009-00354 wherein the Company sought and obtained authorization for the PRP and the PRP rider, the Company estimated total capital expenditures of $124 million to replace approximately 250 miles of bare steel mains and services. In that proceeding, the Company claimed that initial capital expenditures would be approximately $6.7 million in the first year and increase to $10 million annually by the

[59] The Company's claimed rate base in this proceeding is $430 million. The Company projects PRP capital expenditures of $518 million in fiscal years 2018 through 2025, according to its response to Staff 2-18 in this proceeding, which I subsequently address in greater detail.

15th and last year of the program.[60] The Company actually spent and projects that it will spend through 2025 nearly $700 million on PRP projects, more than five and a half times the cost that it estimated in Case No. 2009-00354.[61] The Company projects that it will spend more than $500 million after fiscal year 2017, more than four times the cost that it estimated in Case No. 2009-00354.[62] To be fair, these PRP costs include the Shelbyville Line and the Lake City Line, which are estimated to cost $21.7 million and $5.7 million, respectively.[63]

Atmos Energy Company Kentucky
Pipeline Replacement Program Capital Expenditures
Actual through 2017; Projected 2018-2025

Year	Annual PRP Capital Expend	Cumul PRP Cap Expend	Cumul PRP Cap Exp Aft 2017
2011	3,741,125	3,741,125	
2012	17,300,344	21,041,469	
2013	17,171,794	38,213,263	
2014	22,691,182	60,904,445	
2015	36,926,441	97,830,886	
2016	29,968,709	127,799,595	
2017	39,898,050	167,697,645	
2018	44,900,000	212,597,645	44,900,000
2019	51,100,000	263,697,645	96,000,000
2020	56,900,000	320,597,645	152,900,000
2021	63,200,000	383,797,645	216,100,000
2022	63,100,000	446,897,645	279,200,000
2023	70,700,000	517,597,645	349,900,000
2024	79,200,000	596,797,645	429,100,000
2025	88,700,000	685,497,645	517,800,000

Q. Has the Company achieved savings in O&M expense due to the PRP, as claimed in

[60] Direct Testimony of Earnest B. Napier, P.E. at 12-13, and 19 in Case No. 2009-00354. I have attached the relevant pages from Mr. Napier's testimony in that case as my Exhibit___(LK-17).

[61] The total cost includes the estimated cost to replace the Lake City Line. The Commission authorized the addition of this line through the PRP in Case No. 2017-00308.

Case No. 2009-00354?

A. No. In response to the question, "How will the PRP affect O&M expense?" in the initial PRP case, the Company answered that it "anticipates a significant reduction in leakage which, in turn, will impact operations and maintenance expense over the duration of the PRP."[64]

Now, after $168 million in PRP capital expenditures, the Company has achieved $0.110 million in cumulative O&M expense savings since 2011, or an average of $0.016 million annually. Perhaps rather obviously, the savings are minimal compared to the PRP capital expenditures, which now have a revenue requirement of more than $15 million annually.

VII. PIPELINE REPLACEMENT PROGRAM AND RIDER

Q. Do you have any further comments regarding the PRP and the PRP rider?

A. Yes. The Commission expressed its concern over the significant cost increases in the PRP costs in its Order in Case No. 2017-00308 and indicated that it would conduct a "more detailed review" in this proceeding.[65] The Commission should consider

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[62] Company's response to Staff 2-18. I have attached a copy of this response as my Exhibit___(LK-18).
[63] Order in Case No. 2017-00308 at 3.
[64] Direct Testimony of Earnest B. Napier, P.E. at 18 in Case No. 2009-00354. I have attached the relevant pages from Mr. Napier's testimony in that case as my Exhibit___(LK-19).
[65] Order in Case No. 2017-00308 at 3.

terminating the PRP and the PRP rider, or at least capping the annual rate of increases through the PRP rider. The PRP and PRP rider have been a growth vehicle for the Company to increase its earnings through what is essentially a guaranteed return on PRP investment, while steadily increasing customer rates between base rate increases.

Q. Will termination of the PRP and PRP rider impact the safety and reliability of the Atmos system in Kentucky?

A. It should not. The Company is obligated to operate its system in a prudent and reasonable manner regardless of whether the Commission maintains a PRP or the PRP rider. The Company can recover its prudent and reasonable costs by filing traditional general rate cases, the same as it did before the Commission adopted the PRP and PRP rider in Case No. 2009-00354. In its general rate case proceedings, the Company uses a forecast test year so that its revenues after rates are reset will equal its allowed forecast costs during the first year. This also will provide the Company a behavioral incentive to carefully prioritize and control its costs after the first year between base rate cases.

Q. Is there another reason to terminate the PRP and PRP rider?

A. Yes. The Company's customer base is barely growing. 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 in the next four to eight years. The Commission should encourage prioritization of capital expenditures and the exercise of control over these costs and operating expenses through the behavioral incentives inherent in the traditional general rate case process.

VIII. RESEARCH AND DEVELOPMENT RIDER

Q. Describe the Company's present Research and Development Rider.

A. The Company presently recovers $0.056 million annually from customers through the R&D rider.[66] It then remits these amounts to the Gas Technology Institute ("GTI"), which ostensibly conducts research for the gas industry. The Company's participation in research and funding for GTI is discretionary. The Company does not record the revenue from the R&D rider on its accounting books, but rather considers itself as an agent in that it collects and remits the amounts collected from its customers.[67]

Q. Describe the Company's request to increase the R&D rider revenue requirement.

A. The Company seeks to increase the R&D rider and its annual funding contribution to

[66] Direct Testimony of Mark A. Martin at 21.

GTI to $0.278 million, an increase of $0.222 million.[68] The Company proposes an increase of nearly 400%.

Q. What is your recommendation?

A. I recommend that the Commission terminate the R&D rider, or alternatively, reject the Company's request to increase the rider and funding to GTI. The Company has failed to justify the GTI funding with any direct benefit to Kentucky customers, let alone justify an increase in the GTI funding. The funding is entirely discretionary. The Commission should consider whether it is the responsibility of the Company's customers to sponsor research that benefits industry vendors and manufacturers, essentially subsidizing their product development research.

Q. Does this complete your testimony?

A. Yes.

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[67] Company's response to AG 1-46. I have attached a copy of this response as my Exhibit___(LK-20).
[68] Direct Testimony of Mark A. Martin at 21.

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
16th day of January 2018.

Notary Public

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

BEFORE THE

PUBLIC SERVICE COMMISSION OF THE

COMMONWEALTH OF KENTUCKY

IN RE:	**APPLICATION OF ATMOS ENERGY**	**)**	
	CORPORATION FOR AN	**)**	**CASE NO. 2017-00349**
	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 2018

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)

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 2018

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 2018**

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

Expert Testimony Appearances
of
Lane Kollen
As of January 2018

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

Expert Testimony Appearances
of
Lane Kollen
As of January 2018

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

**Expert Testimony Appearances
of
Lane Kollen
As of January 2018**

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 2018**

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 2018

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 2018

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 2018

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

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

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

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

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

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

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

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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	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.

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

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

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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.

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

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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	CO	CF&I Steel, Rocky Mountain Steel Mills LP, Climax Molybdenum Company	Public Service Company of Colorado	Forecasted test year, historic test year, proforma adjustments for major plant additions, tax depreciation.
09/09	6680-UR-117 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Power and Light Company	Revenue requirements, CWIP in rate base, deferral mitigation, payroll, capacity shutdowns, regulatory assets, rate of return.
10/09	09A-415E Answer	CO	Cripple Creek & Victor Gold Mining Company, et al.	Black Hills/CO Electric Utility Company	Cost prudence, cost sharing mechanism.
10/09	EL09-50 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
10/09	2009-00329	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Trimble County 2 depreciation rates.
12/09	PUE-2009-00030	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Return on equity incentive.

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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.

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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.

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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.

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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.

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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.

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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	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.

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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.

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

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

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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	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.

EXHIBIT ____ (LK-2)

REQUEST:

Refer to electronic workpaper "ADIT_for_KY_-_2017" provided in response to the Staff's First Set of Data Requests. Refer further to the worksheet tab for Division 002 - Shared Services. For the following account 190 ADIT descriptions and amounts as of March 31, 2019, (1) describe in detail the temporary difference that produced the ADIT; (2) define how the Company included or excluded the costs associated with the temporary differences in the revenue requirement; and, (3) provide the Company's justification for inclusion in the revenue requirement given the Company's revenue requirement treatment of the costs that produced the ADIT.

a. MIP/VPP Accrual - $1,498,907

b. Self Insurance - Adjustment - $2,915,283

c. SEBP Adjustment - $26,316,340

d. Restricted Stock Grant Plan - $4,631,448

e. Rabbi Trust - $1,442,452

f. Restricted Stock - MIP - $12,632,356

g. Director's Stock Awards - $5,939,395

h. Charitable Contribution Carryover - $11,032,917

i. VA Charitable Contributions - $(9,275,764)

RESPONSE:

a)

1) MIP/VPP accrual is the accrual of bonuses under the Management Incentive Plan and the Variable Pay Plan. The bonuses are accrued throughout the year and paid subsequent to year end. For financial reporting purposes, these accruals are made throughout the year to accounts 2420.27307, 2420.27349 and 2530.27703 with a corresponding entry to expense. For tax, these amounts are only deductible when paid during or within 2 ½ months

after the tax year end, per IRC §404. As a result, a deferred tax asset is booked for the amount expensed for books but not yet deductible for tax.

2) The expenses associated with the item are excluded as shown on Exhibit GKW-2.

3) The Company has included the balance as a component of ADIT consistent with prior filings in Kentucky including in Case No. 2013-00148 and Case No. 2015-00343. However, in recognition of the Company's response to part 2, the Company would not be opposed to removing the balance from ADIT.

b)

1) The Company self insures itself for certain losses and contingencies. The Company accrues an expense to establish the self insurance reserves on the general ledger in accounts 2282.28101 and 2282.28104. Once a loss, which is covered by a self insurance reserve, is realized by the Company, the payment of that loss is made out the accrual which has been established on the general ledger. For tax purposes, pursuant to §461(h), liabilities may only be deducted when all events which establish the fact of the liability have occurred, the amounts can be determined with reasonable accuracy, and economic performance has occurred. A deferred tax asset is booked for those expenses recognized for books but not yet deductible for tax.

2) The expenses associated with the item are included in Employee Welfare expense consistent with prior practice including in Case No. 2013-00148 and Case No. 2015-00343.

3) Because the expense is included in revenue requirement, the balance is properly included in ADIT.

c)

1) The Company accrues a liability to meet the future obligations associated with supplemental executive benefits. For book purposes, the accruals are recorded to expense and a liability is established in accounts 2530.27712, 2530.27713 and 2420.27388. For tax purposes, supplemental executive benefits are not deductible until paid, pursuant to §409A. A deferred tax asset is booked for those expenses currently recognized for financial reporting purposes but not yet deductible for tax.

2) The expenses associated with the item are included in Employee Welfare expense consistent with prior practice including in Case No. 2013-00148 and Case No. 2015-00343.

3) Because the expense is included in revenue requirement, the balance is properly included in ADIT.

d)

1) Restricted stock units are granted to employees. There is a difference between when the expense associated with the unit grants is recognized for financial reporting purposes versus when the expense is recognized for tax purposes. For financial reporting purposes, the value of the units at the date of grant is amortized over three years starting on the date of grant. For tax purposes, pursuant to IRC code section 83(h), the expense cannot be recognized until the units vest and stock is awarded. This results in a timing difference and a deferred tax asset for the amortization recognized for financial reporting purposes but not yet deductible for tax. Restricted stock is amortized through accounts 2110-10253, 2110-10255, 2110-10257 and 2110-10261.

2) The expenses associated with the item are excluded as shown on Exhibit GKW-2.

3) The Company has included the balance as a component of ADIT consistent with prior filings in Kentucky including in Case No. 2013-00148 and Case No. 2015-00343. However, in recognition of the Company's response to part 2, the Company would not be opposed to removing the balance from ADIT.

e)

1) Accumulated appreciation, impairments of investment assets, contributions and distributions on Rabbi Trust assets are tracked in general ledger account 1860.13992. For book purposes, an investment asset may be impaired when management believes the decline in the fair value of the investment is not temporary. For tax purposes, an impaired investment asset is not a valid tax deduction until the underlying investment is sold. Book and tax basis are the same for appreciation, cash contributions and distributions. The Rabbi Trust deferred tax balance equals the impaired assets allowed as a loss for books but not yet a valid tax deduction.

2) The entries related to the item as described in part (1) support the funding of benefits described in part c and are included in Employee Welfare expense consistent with prior practice including in Case No. 2013-00148 and Case No. 2015-00343.

3) Because the expense is included in revenue requirement, the balance is properly included in ADIT.

f)

1) For book purposes, the restricted stock granted is amortized over a three year purposes. For tax purposes, the compensation expense is not allowed until the restricted stock has vested, pursuant to IRC §83. This timing difference results in a deferred tax asset equal to the book amortization on the restricted stock not yet deductible for tax.

2) The expenses associated with the item are excluded as shown on Exhibit GKW-2.

3) The Company has included the balance as a component of ADIT consistent with prior filings in Kentucky including in Case No. 2013-00148 and Case No. 2015-00343. However, in recognition of the Company's response to part 2, the Company would not be opposed to removing the balance from ADIT.

g)

1) This deferred item reflects the difference between the book and tax treatment of the expense related to restricted stock issued to the Board of Directors. For financial reporting purposes, the expense for Director's Stock is recorded in general ledger account 9302.04113 in the year the stock is granted. Pursuant to IRC §83(h), for tax purposes the expense cannot be recognized until the stock is fully vested. A deferred tax asset is created for the book expense recognized but not yet deductible for tax.

2) The expenses associated with the item are included in Directors & Shareholders expense consistent with prior practice including in Case No. 2013-00148 and Case No. 2015-00343.

3) Because the expense is included in revenue requirement, the balance is properly included in ADIT.

h)

1) For financial statement purposes, charitable contributions are deducted when paid. For tax purposes, pursuant to §170(b)(2) the total deductions for any taxable year shall not exceed 10 percent of the taxpayer's taxable income. Per §170(d)(2), any contribution made by a corporation in a taxable year in excess of the amount deductible for such year under subsection (b)(2)(A) shall be deductible for each of the 5 succeeding taxable years in order of time. The ADIT item represents the contributions deducted for book purposes and not yet deductible for tax.

2) The expenses associated with the item are excluded as charitable contributions are coded to account 426.

3) The Company has included the balance as a component of ADIT consistent with prior filings in Kentucky including in Case No. 2013-00148 and Case No. 2015-00343. However, in recognition of the Company's response to part 2, the Company would not be opposed to removing the balance from ADIT.

i)

1) Pursuant to §170(d)(2), any contribution made by a corporation in a taxable year in excess of the amount deductible for such year under subsection (b)(2)(A) shall be deductible for each of the 5 succeeding taxable years. This valuation allowance was established to reduce the deferred tax asset related to charitable contributions due to circumstances leading the Company to believe it is more likely than not that the benefit from certain charitable contributions will not be realized.

2) The expenses associated with the item are excluded as charitable contributions are coded to account 426.

3) The Company has included the balance as a component of ADIT consistent with prior filings in Kentucky including in Case No. 2013-00148 and Case No. 2015-00343. However, in recognition of the Company's response to part 2, the Company would not be opposed to removing the balance from ADIT.

Respondents: Jennifer Story and Greg Waller

EXHIBIT ____ (LK-3)

REQUEST:

Refer to electronic workpaper "ADIT_for_KY_-_2017" provided in response to the Staff's First Set of Data Requests. Refer further to the worksheet tabs for Division 009 - Kentucky and Division 012 - Shared Services. For the following account 190 ADIT descriptions and amounts as of March 31, 2019, (1) describe in detail the temporary difference that produced the ADIT; (2) define how the Company included the costs associated with the temporary differences in the revenue requirement; and, (3) provide the Company's justification for inclusion in the revenue requirement given the Company's revenue requirement treatment of the costs that produced the ADIT.

a. MIP/VPP Accrual (Division 009) - ($18,182)

b. MIP/VPP Accrual (Division 012) - ($574,777)

RESPONSE:

a)

1) Please see the Company's response to AG DR No. 1-33 subpart (a).

2) The expenses associated with the item are excluded as shown on exhibit GKW-2.

3) The Company has included the balance as a component of ADIT consistent with prior filings in Kentucky including in Case No. 2013-00148 and Case No. 2015-00343. However, in recognition of the Company's response to part 2, the Company would not be opposed to removing the balance from ADIT.

b)

1) Please see the Company's response to AG DR No. 1-33 subpart (a).

2) The expenses associated with the item are excluded as shown on exhibit GKW-2.

3) The Company has included the balance as a component of ADIT consistent with prior filings in Kentucky including in Case No. 2013-00148 and Case No. 2015-00343. However, in recognition of the Company's response to part 2, the Company would not be opposed to removing the balance from ADIT.

Respondents: Jennifer Story and Greg Waller

EXHIBIT ____ (LK-4)

REQUEST:

Refer to electronic workpaper "ADIT_for_KY_-_2017" provided in response to the Staff's First Set of Data Requests. Refer further to the worksheet tab for Division 091 - KY/Mid States. For the following account 190 ADIT descriptions and amounts as of March 31, 2019, (1) describe in detail the temporary difference that produced the ADIT; (2) define how the Company included or excluded the costs associated with the temporary differences in the revenue requirement; and, (3) provide the Company's justification for inclusion in the revenue requirement given the Company's revenue requirement treatment of the costs that produced the ADIT.

a. MIP/VPP Accrual - ($17,997)

b. SEBP Adjustment - $1,389,076

c. Reg Asset Benefit Accrual - $157,983

RESPONSE:

a)

1) Please see the Company's response to AG DR No. 1-33 subpart (a).

2) The expenses associated with the item are excluded as shown on exhibit GKW-2.

3) The Company has included the balance as a component of ADIT consistent with prior filings in Kentucky including in Case No. 2013-00148 and Case No. 2015-00343. However, in recognition of the Company's response to part 2, the Company would not be opposed to removing the balance from ADIT.

b)

1) Please see the Company's response to AG DR No. 1-33 subpart (c).

2) The expenses associated with the item are included in Employee Welfare expense consistent with prior practice including in Case No. 2013-00148 and Case No. 2015-00343.

3) Because the expense is included in revenue requirement, the balance is properly included in ADIT.

c)

1) For book purposes certain benefit costs are capitalized to various 1823 accounts. For tax purposes such expenses are deductible when paid as ordinary and necessary business expenses under IRC Section 162.

2) The expenses associated with the item are included in Benefits expense consistent with prior practice including in Case No. 2013-00148 and Case No. 2015-00343.

3) Because the expense is included in revenue requirement, the balance is properly included in ADIT.

Respondents: Jennifer Story and Greg Waller

EXHIBIT ____ (LK-5)

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2017-00349
Computation of State & Federal Income Tax
Base Period: Twelve Months Ended December 31, 2017
Forecasted Test Period: Twelve Months Ended March 31, 2019

FR 16(8)(e)
Schedule E
Witness: Waller

Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).____________________

Line No.	Description	Base Period Unadjusted	Adjustments	Test Period Fully Adjusted	Sched. Ref.
		(1)	(2)	(3)	
1	Operating Income before Income Tax & Interest	$ 40,525,231	$ (2,747,478)	$ 37,777,753	C-2
2	Interest Deduction	8,306,019	1,653,575	9,959,593	*
3	Taxable Income	$ 32,219,213	$ (4,401,053)	$ 27,818,160	
4	Composite Tax Rate (state & federal)	38.900%		38.900%	* *
5	**State & Federal Income Tax**	$ 12,533,274	$ (1,712,009)	**$ 10,821,264**	
	* Interest Expense Calculation:				
6	13 Month Average Rate Base	$369,386,897		$430,063,026	B-1
7	Weighted cost of Debt	2.25%		2.32%	J-1
8	Interest Expense	$ 8,306,019		$ 9,959,593	

9	2015 * * Composite Tax Rate Calculation: 6.00% + 35%(100% - 6.00%) = 38.900%	
10	State Tax Rate	6.00%
11	Federal Tax Rate	35.00%

EXHIBIT ____ (LK-6)

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2017-00349
Deferred Credits and Accumulated Deferred Income Taxes
as of March 31, 2019

Data:_____Base Period___X__Forecasted Period
Type of Filing:___X____Original________Updated
Workpaper Reference No(s).

FR 16(8)(b)5
Sch. B-5 F
Witness: Waller

Line No.	Account	Period End	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Jurisdictional Period ending Balance	13-Month Average	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
	DIVISION 09								
1	Account 190 - Accumulated Deferred Income Taxes	$ 2,480,404	100%	100%	$ 2,480,404	$ 2,480,404	100%	100%	$ 2,480,404
2									
3	Account 282 - Accumulated Deferred Income Taxes	(127,528,305)	100%	100%	(127,528,305)	(123,986,274)	100%	100%	(123,986,274)
4									
5	Account 283 - Accumulated Deferred Income Taxes - Other	(103,015)	100%	100%	(103,015)	(103,015)	100%	100%	(103,015)
6									
7	Div 09 Accumulated Deferred Income Taxes	$(125,150,916)			$ (125,150,916)	$ (121,608,885)			$ (121,608,885)
8									
9	**DIVISION 02**								
10	Account 190 - Accumulated Deferred Income Taxes	$ 822,699,628	10.35%	50.25%	$ 42,788,738	$ 822,699,628	10.35%	50.25%	$ 42,788,738
11									
12	Account 282 - Accumulated Deferred Income Taxes	(25,837,739)	10.35%	50.25%	(1,343,825)	(24,883,174)	10.35%	50.25%	(1,294,178)
13									
14	Account 283 - Accumulated Deferred Income Taxes - Other	25,919,297	10.35%	50.25%	1,348,067	25,919,297	10.35%	50.25%	1,348,067
15									
16	Div 02 Accumulated Deferred Income Taxes	$ 822,781,186			$ 42,792,980	$ 823,735,751			$ 42,842,627
17	**DIVISION 12**								
18	Account 190 - Accumulated Deferred Income Taxes	$ (574,777)	10.93%	51.88%	$ (32,595)	$ (574,777)	10.93%	51.88%	$ (32,595)
19									
20	Account 282 - Accumulated Deferred Income Taxes	(23,828,557)	10.93%	51.88%	(1,351,295)	(24,869,504)	10.93%	51.88%	(1,410,326)
21									
22	Account 283 - Accumulated Deferred Income Taxes - Other	0	10.93%	51.88%	0	0	10.93%	51.88%	0
23									
24	Div 012 Accumulated Deferred Income Taxes	$ (24,403,334)			$ (1,383,890)	$ (25,444,281)			$ (1,442,921)
25	**DIVISION 91**								
26	Account 190 - Accumulated Deferred Income Taxes	$ 6,309,382	100%	50.25%	$ 3,170,550	$ 6,309,382	100%	50.25%	$ 3,170,550
27									
28	Account 255 - Accumulated Deferred Investment Tax Credits	(1)	100%	50.25%	(1)	(1)	100%	50.25%	(1)
29									
30	Account 282 - Accumulated Deferred Income Taxes	5,709,565	100%	50.25%	2,869,134	5,699,565	100%	50.25%	2,864,109
31									
32	Account 283 - Accumulated Deferred Income Taxes - Other	(1,597,357)	100%	50.25%	(802,694)	(1,597,357)	100%	50.25%	(802,694)
33									
34	Div 91 Accumulated Deferred Income Taxes	$ 10,421,589			$ 5,236,990	$ 10,411,589			$ 5,231,965
35									
36									
37	**Total Deferred Inc. Taxes and Investment Tax Credits**	$ 683,648,525			$ (78,504,836)	$ 687,094,174			$ (74,977,214)
38	*(excluding forecasted change in NOLC)*								
39	**Forecasted Change in NOLC**								(321,485)
40									
41	**Forecasted 13-month Average ADIT in Rate Base**								**(75,298,698)**
42									

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2017-00349
Deferred Credits and Accumulated Deferred Income Taxes
as of March 31, 2019

Data:_____Base Period__X__Forecasted Period
Type of Filing:___X____Original________Updated
Workpaper Reference No(s).

FR 16(8)(b)5
Sch. B-5 F
Witness: Waller

Line No.	Account	Period End	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Jurisdictional Period ending Balance	13-Month Average	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
43	**Calculation of Change in NOLC**								
44	**(from 13-month average Base Period to 13-month average Forecasted Period**								
45				Schedule					
46	Forecasted Test Period			Reference					
47									
48	13-month average Rate Base			B.1 F		430,063,026			
49									
50	Required Operating Income			A.1		33,243,872			
51									
52	Interest Deduction			E.1		9,959,593			
53									
54	Return on Equity Portion of Rate Base			line 50 - line 52		23,284,279			
55									
56	Return, grossed up for Income Tax	38.90%		Line 54 / (1-tax rate)		38,108,476			
57									
58	Tax Expense on Return	38.90%		Line 56 x tax rate		14,824,197			
59									
60	Change In ADIT, excluding forecasted change in NOLC			Line 37; B.5 B		(14,502,713)			
61	Required Change in NOLC					(321,485)		0	
62									
63	**Total Required Change in Accumulated Deferred Income Taxes**[1]			**B.1 F; B.1 B**		**(14,824,197)**			
64									
65									
66	**ADIT Reconciliation**								
67	**13-Month Average ADIT, Base Period**			**B.5 B**		**(60,474,501)**			
68									
69	13-Month Average ADIT, Forecasted Period, excl, Change in NOLC			Line 37		(74,977,214)			
70	Change in NOLC			Line 39		(321,485)			
71	**Forecasted 13-month Average ADIT in Rate Base**					**(75,298,698)**			
72									
73	**Total Required Change in Accumulated Deferred Income Taxes**			Line 71 - Line 67		**(14,824,197)**			
74									
75									
76	[1] *Because the Company is in a NOLC position, the total change in ADIT must equal the tax expenses included in revenue requirement*								

EXHIBIT ____ (LK-7)

ATO-CWC1 A

Atmos Energy Corporation-Kentucky
Cash Working Capital Lead/Lag Analysis
For Forecast Test Year Ended March 31, 2019

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		78,709,117	215,641	*CWC2*	39.06	*CWC3*	39.25	(0.19)	(40,972)
3										
4	Operation and Maintenance Expense									
5	O&M, Labor		10,502,421	28,774	*CWC2*	39.06	*CWC4*	14.06	25.00	719,350
6	O&M, Non-Labor		15,661,608	42,909	*CWC2*	39.06	*CWC5*	21.43	17.63	756,486
7	Total O&M Expense		26,164,029							1,475,836
8										
9	Taxes Other Than Income									
10	Ad Valorem		5,076,000	13,907	*CWC2*	39.06	*CWC6*	299.77	(260.71)	(3,625,714)
11	Taxes Property and Other		134,427	368	*CWC2*	39.06	*CWC6*	(45.37)	84.43	31,072
12	Payroll Taxes		383,364	1,050	*CWC2*	39.06	*CWC6*	15.14	23.92	25,114
13	Franchise and other pass through		7,665,356	21,001	*CWC2*	39.06	*CWC6*	41.59	(2.53)	(53,054)
14	Public Service Commission		340,776	934	*N/A*	0.00	*CWC6*	0.00	0.00	0
15	DOT		82,281	225	*CWC2*	39.06	*CWC6*	59.00	(19.94)	(4,487)
16										
17	Allocated Taxes-Shared Services									
18	Ad Valorem	22%	78,997	216	*CWC2*	39.06	*CWC6*	213.50	(174.44)	(37,679)
19	Payroll Taxes	78%	282,393	774	*CWC2*	39.06	*CWC6*	15.14	23.92	18,513
20										
21	Allocated Taxes-Business Unit									
22	Ad Valorem	1%	1,809	5	*CWC2*	39.06	*CWC6*	299.77	(260.71)	(1,304)
23	Payroll Taxes	99%	186,399	511	*CWC2*	39.06	*CWC6*	15.14	23.92	12,222
24	Total Taxes Other Than Income		14,231,801							(3,635,316)
25										
26	Federal Income Tax		*10,153,585*							
27	Current Taxes		0	0	*CWC2*	39.06	*CWC7*	29.75	9.31	0
28	Deferred Taxes		10,153,585	27,818	*CWC2*	39.06	*CWC7*	0.00	39.06	1,086,571
29										
30	State Income Tax		648,101							
31	Current Taxes		0	0	*CWC2*	39.06	*CWC8*	29.75	9.31	0
32	Deferred Taxes		648,101	1,776	*CWC2*	39.06	*CWC8*	0.00	39.06	69,371
33										
34	Depreciation		21,561,512	59,073	*CWC2*	39.06		0	39.06	2,307,391
35										
36	Interest Expense - STD		729,904	2,000	*CWC2*	39.06	*(1)*	63.40	(24.34)	(48,680)
37										
38	Interest Expense - LTD		9,230,437	25,289	*CWC2*	39.06	*CWC9*	90.61	(51.55)	(1,303,769)
39										
40	Return on Equity		23,268,157	63,748	*CWC2*	39.06		0	39.06	2,489,997
41										
42	TOTAL		184,696,644							2,400,429
43										
44	(1) Please see relied file labeled "CWC1 STD Days Outstanding.pdf (Page 9)" for calculation of average days held									

EXHIBIT ____ (LK-8)

REQUEST:

Provide the expense by FERC account that was incurred to develop the Cash Working Capital lead/lag study in this proceeding. Identify and quantify each component of this expense. For each component, indicate if this expense was an incremental cost that otherwise would not have been incurred. Provide all support for your response.

RESPONSE:

The Cash Working Capital Study was prepared entirely by Company employees. The Company did not track the time employees spent on preparing the Study. There are no incremental costs associated with the Study.

Respondent: Joe Christian

EXHIBIT ____ (LK-9)

REQUEST:

Refer to the electronic workpaper "OM_for_KY-2017" provided in response to the Staff's First Set of Data Requests and the tab entitled "Div 9 forecast."

a. Provide the actual data in the same level of detail and in the same format for each month from October 2013 through the most recent month available in live spreadsheet format.

b. Provide a variance analysis for each category of expense (labor, benefits, employee welfare, etc.) that identifies and describes all reasons for the change projected in the test year compared to the actual expense for calendar year 2016. In addition, provide all documents, including studies and/or other analyses developed by the Company to support the change projected in the test year compared to the actual expense for calendar year 2016.

c. Provide a variance analysis for each category of expense (labor, benefits, employee welfare, etc.) that identifies and describes all reasons for the change projected in the test year compared to the base year. In addition, provide all documents, including studies and/or other analyses developed by the Company to support the change projected in the test year compared to the base year.

RESPONSE:

a) Please see Attachment 1.

b) Please see Attachment 2.

c) Please see Attachment 2.

ATTACHMENTS:

ATTACHMENT 1 - Atmos Energy Corporation, AG_1-22_Att1 - O&M Div 009 Oct13-Sep17.xlsx, 27 Pages.

ATTACHMENT 2 - Atmos Energy Corporation, AG_1-22_Att2 - Div 009 O&M Variances.xlsx, 2 Pages.

Respondents: Laura Gillham and Greg Waller

Atmos Energy Corporation
Kentucky / Mid-States Division
Kentucky Operations
Case No. 2017-00349
AG 1 - 22 Part B

	Test Year	Actuals CY 2016	Difference		Explanation
Labor	5,015,768	5,099,070	(83,301)	-1.63%	Change between test year and CY 2016 is 1.63% variance and immaterial
Benefits	1,741,158	1,957,208	(216,050)	-11.04%	The CY 2016 actual months include a benefit variance. Positive or negative load factor variances are not assumed in the budget (test year)
Employee Welfare	112,767	135,669	(22,902)	-16.88%	Test year based on FY 2018 budget where assumption of normal (100% of target) incentive payout is anticipated. Incentive compensation is removed from revenue requirement as a ratemaking adjustment. Various miscellanous employee welfare expenses (ex. flu shots, newspapers, etc.) are budgeted at the General Office rate division (091) but coded to the state specific rate division when applicable.
Insurance	5,640	178,228	(172,589)	-96.84%	Insurance is budgeted at the General Office rate division (091). As insurance expenses are incurred, they are coded to the state specific rate division.
Rent, Maint., & Utilities	524,452	633,840	(109,388)	-17.26%	Rent expense is no longer incurred for the Danville, Paducah, and Campbellsville offices.
Vehicles & Equip	1,018,243	822,707	195,536	23.77%	Primary driver is the replacement of leased vehicles in accordance with our company vehicle replacement guidelines.
Materials & Supplies	749,371	722,369	27,003	3.74%	Change between test year and CY 2016 is 3.74% variance and immaterial
Information Technologies	-	11,002	(11,002)	-100.00%	Information Technologies are largely budgeted at the General Office rate division (091). As IT expenses are incurred, they are coded to the state specific rate division.
Telecom	298,878	264,596	34,283	12.96%	Increase primarily driven by additional WMR tower leases that have gone into effect in 2017 .
Marketing	191,385	184,543	6,842	3.71%	Change between test year and CY 2016 is 3.71% variance and immaterial
Directors & Shareholders &PR	-	0	0		N/A
Dues & Membership Fees	60,556	85,027	(24,471)	-28.78%	Dues and Donations are primarily budgeted at the General Office rate division (091). As actual expenses are incurred, they are coded to the state specific rate division when applicable.
Print & Postages	13,166	18,786	(5,620)	-29.92%	Change between base and test period is $5,620 and immaterial.
Travel & Entertainment	456,769	400,913	55,855	13.93%	Increase in travel expenses associated with increase employee training at the Company's training center in Plano, TX.
Training	13,231	11,863	1,369	11.54%	Change between base and test period is $1,369 and immaterial.
Outside Services	2,970,827	3,450,448	(479,621)	-13.90%	Company incurred $846,759 in settlement costs in CY 2016. As a normal course of business, we do not budget for settlements and the test year is largerly based on budget.
Provision for Bad Debt	362,112	490,589	(128,476)	-26.19%	Company reviews the bad debt balances on a quarterly basis and makes any necessary true-up provision entries.
Miscellaneous	17,510	51,553	(34,043)	-66.03%	Company incurred approximately $20,000 in Kentucky Press Association charges associated with rate change notifications in CY 2016.
Total O&M Expenses Before Allocations	**13,551,833**	**14,518,409**	**(966,577)**		

EXHIBIT ____ (LK-10)

REQUEST:

Refer to the electronic workpaper "OM_for_KY-2017" provided in response to the Staff's First Set of Data Requests and the tab entitled "Div 91 forecast."

a. Provide the actual data in the same level of detail and in the same format for each month from October 2013 through the most recent month available in live spreadsheet format.

b. Provide a variance analysis for each category of expense (labor, benefits, employee welfare, etc.) that identifies and describes all reasons for the change projected in the test year compared to the actual expense for calendar year 2016. In addition, provide all documents, including studies and/or other analyses developed by the Company to support the change projected in the test year compared to the actual expense for calendar year 2016.

c. Provide a variance analysis for each category of expense (labor, benefits, employee welfare, etc.) that identifies and describes all reasons for the change projected in the test year compared to the base year. In addition, provide all documents, including studies and/or other analyses developed by the Company to support the change projected in the test year compared to the base year.

d. Refer to cell rows 254 and 255 of this tab for the following two accounts: Customer accounts-Customer rec - Collection Fees 9030-06112 and Customer accounts-Customer rec - Bill Print Fees 9030-06116. Large net increases for these two accounts begin to occur in the first projected month of July 2017 from a run rate during the first six months actual in 2017 of approximately $38,000 per month to over $170,000 per month thereafter. Describe all reasons for the projected increase and confirm whether or not the projected amount should be reduced and why.

e. Refer to cell row 252 of this tab for the following account: Customer accounts-Customer rec - Payment Services 9030-06113. Explain all reasons why this appears to be a new expense of over $60,000 per month starting in June 2017 and continuing through the end of the projected test year. Describe the source of the expense and define the source and reasons for the expense. If not a new expense and just a reclassification, so state.

RESPONSE:

a) Please see Attachment 1.

b) Please see Attachment 2.

c) Please see Attachment 2.

d) The anomaly is caused by the correcting entry ($387,158 credit) in March 2017 with an offsetting entry in Division 009. Because the entry occurred during the historic portion of the base period, it affects how the budget for the expense category is allocated across subaccounts (see the Waller testimony page 22 line 14 through page 23 line 2). Please see the tab "Div 091 FY18 Budget" for the actual budget for those expenses by subaccount. Although the credit entry impacts the allocation of the budget across accounts and subaccounts, it has no ultimate impact on revenue requirement.

e) Subaccount 06113-Payment Services was a new subaccount created in June 2017. These charges, which are for credit card fees and other payment services, were previously recorded within subaccount 06112-Collection Fees. These payment services are not new expenses but instead a reclassification from subaccount 06112 to 06113. Subaccount 06112 still has expenses charged for collection fees.

ATTACHMENTS:

ATTACHMENT 1 - Atmos Energy Corporation, AG_1-23_Att1 - O&M Div 091 Oct13-Sep17.xlsx, 12 Pages.

ATTACHMENT 2 - Atmos Energy Corporation, AG_1-23_Att2 - O&M Div 091 Variance.xlsx, 2 Pages.

Respondents: Laura Gillham and Greg Waller

Atmos Energy Corporation
Kentucky / Mid-States Division
Kentucky Operations
Case No. 2017-00349

AG 1 - 23 Part B

	Unallocated Test Year	Unallocated Actuals CY 2016	Difference		Explanation
Labor	2,297,175	2,139,454	157,721	7.37%	The increase is primarily driven by assumed merit increase of 3% in FY18 budget and additional 3% for October '18 to March '19 (FY19 Budget).
Benefits	1,243,705	649,459	594,246	91.50%	The CY 2016 actuals include a benefit variance. Positive or negative load factor variances are not assumed in the budget (test year)
Employee Welfare	1,018,282	1,471,419	(453,136)	-30.80%	Test year based on FY 2018 budget where assumption of normal (100% of target) incentive payout is anticipated. Incentive compensation is removed from revenue requirement as a ratemaking adjustment.
Insurance	413,223	47,660	365,563	767.02%	Insurance is budgeted at the General Office rate division (091). As insurance expenses are incurred, they are coded to the state specific rate division.
Rent, Maint., & Utilities	322,668	344,643	(21,976)	-6.38%	Change between base and test period is a decrease of $21,976.
Vehicles & Equip	81,481	66,759	14,723	22.05%	Primary driver is the replacement of leased vehicles in accordance with our company vehicle replacement guidelines.
Materials & Supplies	181,655	168,219	13,436	7.99%	
Information Technologies	112,919	88,844	24,075	27.10%	Some IT expenses are budgeted at the General Office rate division (091). As actual expenses are incurred, they are coded to the state specific rate division where applicable.
Telecom	524,369	317,171	207,198	65.33%	Some telecom expenses are budgeted at the General Office rate division (091). As actual expenses are incurred, they are coded to the state specific rate division where applicable.
Marketing	335,411	278,567	56,844	20.41%	Marketing expenses are largely budgeted at the General Office rate division (091). As actual expenses are incurred, they are coded to the state specific rate division where applicable.
Directors & Shareholders &PR	-	0	0		N/A
Dues & Membership Fees	149,994	85,152	64,843	76.15%	Dues and Membership Fees are primarily budgeted at the General Office rate division (091). As actual expenses are incurred, they are coded to the state specific rate division when applicable.
Print & Postages	19,132	13,130	6,002	45.71%	Change between base and test period is $6,002 and immaterial.
Travel & Entertainment	581,339	422,828	158,512	37.49%	Estimated increase associated with travel for Division representation on Enterprise teams as well as attendence at various conferences (i.e. Safety, Compliance, Rates, Human Resources, etc.). Some travel expenses are budgeted at the General Office rate division (091). As these actual expenses are incurred, they are coded to the state specific rate division where applicable.
Training	79,466	52,057	27,409	52.65%	Expected increase in registration costs for attending various conferences (i.e. Safety, Compliance, Rates, Human Resources, etc.)
Outside Services	3,947,609	2,657,948	1,289,662	48.52%	Legal and some other Outside Servces are budgeted at the General Office rate division (091). As expenses are incurred, they are coded to the state specific rate division.
Provision for Bad Debt	-	0	0		N/A
Miscellaneous	100,939	(119,027)	219,967	-184.80%	Change in A&G overhead clearing 9200-04863.
Total O&M Expenses Before Allocations	**11,409,370**	**8,684,283**	**2,725,087**		

EXHIBIT ____ (LK-11)

REQUEST:

Refer to the response to AG 1-33 (g) referencing the inclusion of expense related to Director's Stock being included in Directors and Shareholder's expense recorded in general ledger account 9302.04113 and that being included in the revenue requirement. Provide the amount of expense related to Director's Stock included in the revenue requirement.

RESPONSE:

O&M forecasting is done at the budget category level, rather than FERC account. Per the forecasting methodology Kentucky is allocated approximately $344,806 of Division 002 Directors and Shareholder's PR during the test period, which is a decrease from the base period amount of approximately $355,185. Please see the direct testimony of Company witness Greg Waller at pages 20-23 and 27-33 for an explanation of the Company's overall O&M forecasting process. Please also see the relied upon file "OM for KY-2017 case.xlsx" provided by the Company in response to Staff DR No. 1-71 for account detail.

Respondent: Greg Waller

EXHIBIT ____ (LK-12)

AMENDED RESPONSE (11/21/2017)

REQUEST:

Provide the information requested in Schedule 65 for yearly salary and benefit information for each corporate officer and as a group in total by category of Directors, Managers, Supervisors, Exempt, Non-Exempt, Union, and Non-Union Hourly for the years 2013 through 2016 and the base period (in gross dollars-not hourly or monthly rates). Commission Staff will provide Schedule 65 in Excel format by electronic mail to Counsel for all parties.

a. Regular salary or pay.

b. Overtime pay.

c. Excess vacation payout.

d. Standby/Dispatch pay.

e. Bonus and incentive pay.

f. Any other forms of incentives (may include stock options or forms of deferred compensation).

g. Other amounts paid and reported on the employees' W-2 (specify).

h. Healthcare benefit cost for employees.

   (1) Amount paid by employer.

   (2) Amount paid by employee.

i. Dental benefits cost for employees.

   (1) Amount paid by employer.

   (2) Amount paid by employee.

j. Vision benefits cost for employees.

   (1) Amount paid by employer.

   (2) Amount paid by employee.

k. Life insurance cost for employees.

   (1) Amount paid by employer.

   (2) Amount paid by employee.

l. Accidental death and disability benefits.

   (1) Amount paid by employer.

   (2) Amount paid by employee.

m. Defined Contribution - 401 (k) or similar plan cost for employees. Provide the amount paid by employer.

n. Defined Benefit Retirement cost for employees.

   (1) Amount paid by employer.

   (2) Amount paid by employee.

o. Cost of any other benefit available to an employee (specify).

AMENDED RESPONSE:

Please see amended Confidential Attachment 1 for the requested information. The information provided in the columns Medical (Employee), Medical (Atmos), Dental (Employee) and Dental (Atmos) for 2013, 2015, 2016 and 2017 was calculated using incorrect information in the Company's original response. Please note that the full calendar year 2013 payroll data is not readily available and the Company is providing the information to the extent it is available. The Company does not have any union employees.

ATTACHMENT:

ATTACHMENT 1 - Atmos Energy Corporation, Staff_1-65_Att1_Amended - 2013-2017 Employee Pay and Benefits (CONFIDENTIAL).xlsx, 10 Pages.

Respondents: Laura Gillham, Elma Ramirez and Kim Pettineo

REQUEST:

Refer to the Waller Testimony, page 28, regarding O&M expenses related to labor and benefits expenses. Also refer to Atmos's response to Staff's First Request, Item 65.

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

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

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

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

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

f. Provide the information requested in above Items a. through e. that are passed through to Kentucky by the Division's General Services, Shared Services, and other affiliated companies.

RESPONSE:

a) Please see Confidential Attachment 1.

b) Please see Confidential Attachment 1.

c) Please see Confidential Attachment 1.

d) Please see Confidential Attachment 1. Premiums are paid by the Company for the full basic life insurance coverage amount at a rate per $1,000 of coverage for amounts both under and over $50,000 as reported in the Company's responses to Staff Set 1. Imputed income for tax purposes is calculated on amounts over $50,000 in accordance with IRS guidelines. Imputed income amounts are being provided in the new data set for calendar year 2016 and for calendar year 2017 through August 31, 2017.

e) Please see Confidential Attachment 1.

f) Please see Confidential Attachment 1.

<u>ATTACHMENT:</u>

ATTACHMENT 1 - Atmos Energy Corporation, Staff_2-24_Att1 - 2016 & 2017 Benefits Breakout (CONFIDENTIAL).xls, 2 Pages.

Respondents: Kim Pettineo and Elma Ramirez

Case No. 2017-00349
Atmos Energy Corporation, Kentucky Division
STAFF RFI Set No. 3
Question No. 3-11

REQUEST:

Refer to Atmos's response to Staff's Second Request, Item 24, Attachment 1. If available, provide this same information for the forecasted test year.

RESPONSE:

Because the Company does not budget at the level of detail reflected in the response to Staff 1-65, this information is not available for the test year.

Respondent: Greg Waller

REQUEST:

Confirm that the company has a defined benefit plan.

a. If so confirmed, state: (i) how many employees of Atmos Kentucky participate in the plan; and (ii) the expense included in the test year revenue requirement.

RESPONSE:

The Company has 145 employees in its Kentucky division that participate in the plan.

Please see the Company's responses to Staff DR Nos. 1-65 and 2-24. The amounts presented in those responses present the best data to estimate test year expense at this particular level of detail. Please see the direct testimony of Company Witness Greg Waller at pages 20-23 and 27-33 for an explanation of the Company's O&M forecasting process.

Respondents: Kim Pettineo and Greg Waller

EXHIBIT ____ (LK-13)

REQUEST:

Refer to Schedules C-2.3 B and C-2.3 F at line 5 related to ad valorem costs for the Kentucky Division. Refer also to page 35, lines 3-4 of Mr. Waller's Direct Testimony.

a. Provide all computations and workpaper documentation to compute the budgeted amounts depicted for the Kentucky Division in these schedules and to justify the 57.7% increase in monthly costs from September 2017 to October 2017, $248,199 to $391,500, and another increase to $423,000 per month starting in April 2018. This request goes beyond provision of the Atmos monthly budget amounts, for all Atmos divisions provided in response to the Staff's First Set of requests.

b. Provide the actual ad valorem taxes paid for the Kentucky Division during each of the last three fiscal years 2015, 2016, and 2017 by taxing jurisdiction. This request includes all PRP and non-PRP amounts.

c. Provide separately the actual ad valorem taxes expensed and capitalized for the Kentucky Division during each of the last three fiscal years 2015, 2016, and 2017. This request includes all PRP and non-PRP amounts.

d. Provide the gross plant and the net book value for the Kentucky Division at December 31, 2014, December 31, 2015, December 31, 2016 and September 30, 2017. This request includes all PRP and non-PRP amounts.

e. Provide copies of the latest tax assessment and billing amount for each of the taxing jurisdictions in Kentucky.

RESPONSE:

a) Please see Attachment 1.

b) Please see Attachment 2. The payments for each tax year in question are on separate tabs within this workbook.

c) Please see Attachment 3.

d) Please see Attachment 4 for the gross plant balances.

Net book value is reported on our ad valorem tax returns. Below are the net book values calculated using the same method used for ad valorem tax purposes for KY Div 009:

December 2014 - $278,246,097
December 2015 - $306,427,214
December 2016 - $372,000,041
September 2017 - $408,240,920

e) The latest finalized value we have received from the State of Kentucky is for Tax Year 2015. We are still in negotiations with the State for Tax Year 2016, and we have not yet received our initial value for Tax Year 2017. As such, attached are the following:

- 2015 Settlement Agreement (see Confidential Attachment 5) showing the final settled value of $331,000,000.
- 2015 final values by Jurisdiction (see Confidential Attachment 6).
- 2016 initial value (see Confidential Attachment 7).
- 2016 initial bill from the state which was paid under protest. Atmos Energy paid taxes based on our claimed value and will receive additional tax bills for any difference between the claimed taxes and the settled taxes once the value has been settled. (see Confidential Attachment 8)

ATTACHMENTS:

ATTACHMENT 1 - Atmos Energy Corporation, AG_1-24_Att1 - Calculation of Ad Valorem Tax Expense Estimates.xlsx, 1 Page.

ATTACHMENT 2 - Atmos Energy Corporation, AG_1-24_Att2 - Ad Valorem Taxes Paid for Tax Years 2015-2017 as of 10-31-17.xlsx, 7 Pages.

ATTACHMENT 3 - Atmos Energy Corporation, AG_1-24_Att1 - Ad Valorem Tax FY15-FY17.xlsx, 1 Page.

ATTACHMENT 4 - Atmos Energy Corporation, AG_1-24_Att2 - KY Gross Plant.xlsx, 1 Page.

ATTACHMENT 5 - Atmos Energy Corporation, AG_1-24_Att5 - Atmos Settlement Agrmt 2015 Executed (CONFIDENTIAL).pdf, 8 Pages.

ATTACHMENT 6 - Atmos Energy Corporation, AG_1-24_Att6 - Atmos Energy Corp GNC 5640 2015 Amended Cert (Settled_Final) (CONFIDENTIAL).pdf, 38 Pages.

ATTACHMENT 7 - Atmos Energy Corporation, AG_1-24_Att7 - Atmos Energy Notice of Assessment 2016 (CONFIDENTIAL).pdf, 1 Page.

ATTACHMENT 8 - Atmos Energy Corporation, AG_1-24_Att8 - 2016 State of KY CLAIMED Payment (CONFIDENTIAL).pdf, 10 Pages.

Respondent: Greg Waller

Ad Valorem Expense Calculation	Annualized Taxes	Monthly Taxes	Monthly Adjustment for Prior Over-Accrual Balance	Expense Amount	**Rounded Amount Used for Entries**	Periods where this Calculation is Used
Estimated Calendar Year 2017 Ad Valorem Taxes	4,697,636	391,470	(141,667) *	249,803	**250,000**	Jan-Sep 2017
Estimated Calendar Year 2017 Ad Valorem Taxes	4,697,636	391,470		391,470	**391,500**	Oct-Dec 2017
Projected Percentage Increase for Calendar Year 2018	8%					
Estimated Calendar Year 2018 Ad Valorem Taxes	5,073,447	422,787		422,787	**423,000**	Jan-Sep 2018

* The monthly adjustment during FY 2017 for a prior over-accrual was offset by a one-time adjustment of $1,500,000 in September 2017. The effective adjustment for the fiscal year was ($200,000) as shown below. During late FY 2017, it became apparent that the Tax Year 2016 taxes would be higher than anticipated which was the reason behind the September 2017 entry.

Monthly adjustment to expense	(141,667)
x 12 months	12
FY 2017 Annualized Adjustment	(1,700,000)
+	+
One-Time Adjustment Made in Sept 2017	1,500,000
Effective Adjustment for FY 2017	(200,000)
Effective Monthly Adjustment during FY 2017	(16,667)

Tax Year 2015 Taxes Paid as of 10/31/17

Collector	OCT-15	NOV-15	DEC-15	JAN-16	FEB-16	MAR-16	APR-16	MAY-16	JUN-16	JUL-16	AUG-16	SEP-16	OCT-16	NOV-16	DEC-16	JAN-17	FEB-17
ANDERSON COUNTY SHERIFF														37,515.32		978.45	
BARREN COUNTY SHERIFF					94,676.13												7,342.70
BOYLE COUNTY CLERK																5,727.14	
BRECKINRIDGE COUNTY SHERIFF					15,639.38											338.96	
BURGIN BOARD OF EDUCATION					5,413.74												45.81
CALDWELL COUNTY SHERIFF																37,774.17	
CALHOUN CITY OF					782.29												26.19
CAMPBELLSVILLE INDEPENDENT SCHOOL BRD						44,776.53											3,678.62
CHRISTIAN COUNTY SHERIFF					186,819.21											7,984.25	
CITY OF ADAIRVILLE					1,042.12												
CITY OF AUBURN							3,517.68										
CITY OF BEAVER DAM					3,294.55												104.01
CITY OF BOWLING GREEN KY			3,914.00		244,934.20											25,848.88	
CITY OF CADIZ					3,222.73											67.88	
CITY OF CALVERT CITY																	3,545.73
CITY OF CAMPBELLSVILLE							14,186.62										
CITY OF CAVE CITY																	2,348.21
CITY OF CENTRAL CITY					4,323.16												130.53
CITY OF CLOVERPORT					2,309.04											44.44	
CITY OF CROFTON					5,408.87												40.48
CITY OF DAWSON SPRINGS													6,211.72				96.11
CITY OF EDDYVILLE					2,307.52												39.97
CITY OF ELKTON					2,305.03												34.80
CITY OF GLASGOW																	13,628.79
CITY OF GREENSBURG					2,525.71												
CITY OF GREENVILLE KY					5,164.60												209.20
CITY OF HARDINSBURG					3,794.48											79.33	
CITY OF HARRODSBURG					3,129.80												42.02
CITY OF HARTFORD					3,463.43												139.31
CITY OF HOPKINSVILLE					40,173.85											2,439.24	
CITY OF HORSE CAVE									3,790.93								50.11
CITY OF LEBANON							5,094.39										169.16
CITY OF LIVERMORE					455.05												19.22
CITY OF MADISONVILLE KY													14,782.61				
CITY OF MARION KY																320.91	
CITY OF MAYFIELD			1,725.50		57,626.73												4,422.11
CITY OF MORTONS GAP													298.89				23.49
CITY OF OWENSBORO																	
CITY OF PADUCAH		380.80			90,900.76											104,081.38	16,820.46
CITY OF PRINCETON KY																	7,084.52
CITY OF RUSSELLVILLE					5,228.00												280.18
CITY OF SEBREE					1,100.06											61.40	
CITY OF SHELBYVILLE		1,512.50			19,488.69											1,588.23	
CITY OF SPRINGFIELD KY					1,948.03												36.87
CITY OF STANFORD					1,587.64												
CRITTENDEN COUNTY SHERIFF					14,173.99												
DANVILLE BOARD OF EDUCATION					85,376.19											11,487.25	
DAVIESS COUNTY						364,837.86											27,132.85
DIXON CITY OF					211.21												9.35
EDMONSON COUNTY SHERIFF					2,766.85												46.92
FORDSVILLE CITY OF																	398.40
FRANKLIN COUNTY					5,655.18												83.40
FRANKLIN KENTUCKY CITY OF					3,941.90	122.99											93.68
GARRARD COUNTY SHERIFF					16,440.27												413.27
GRAND RIVERS CITY OF					1,919.26												113.50
GRAVES COUNTY SHERIFF	4,320.77				31,663.01												1,778.89
GRAYSON COUNTY SHERIFF					108.59												
GREEN COUNTY SHERIFF					16,545.23												
HANCOCK COUNTY SHERIFF																	12,053.31
HANSON CITY OF													243.83				
HART COUNTY					26,808.20												328.26
HAWESVILLE CITY OF																	3,097.08
HENDERSON CITY OF					2,807.08												
HENDERSON COUNTY SHERIFF					11,825.77												153.41

Tax Year 2015 Taxes Paid as of 10/31/17

Collector	OCT-15	NOV-15	DEC-15	JAN-16	FEB-16	MAR-16	APR-16	MAY-16	JUN-16	JUL-16	AUG-16	SEP-16	OCT-16	NOV-16	DEC-16	JAN-17	FEB-17
HOPKINS COUNTY SHERIFF													442,634.13				14,606.42
HUSTONVILLE CITY OF					209.77												
JEFFERSON COUNTY SHERIFF			1.05		10,787.72												4.27
JUNCTION CITY CITY OF																641.93	
LAWRENCEBURG CITY OF														4,127.68		217.98	
LINCOLN COUNTY SHERIFF					14,423.27												336.97
LIVINGSTON COUNTY SHERIFF					7,545.04												195.92
LOGAN COUNTY SHERIFF					42,289.08												1,050.61
LYON COUNTY SHERIFF					5,153.19												
MARION COUNTY SHERIFF					21,785.25												658.99
MARSHALL COUNTY																	18,820.16
MCCRACKEN COUNTY			1,204.00		85,822.01												
MCLEAN COUNTY SHERIFF					14,745.63												412.88
MERCER COUNTY					50,698.41												806.34
MUHLENBERG COUNTY SHERIFF					49,706.12												924.78
MUNFORDVILLE CITY OF					1,928.95												31.35
NORTONVILLE CITY OF													1,154.20				37.62
OHIO COUNTY					20,587.50												571.67
PARK CITY CITY OF																	556.28
PERRYVILLE CITY OF												718.48				22.13	
POWDERLY CITY OF					1,288.28												
SACRAMENTO CITY OF					356.93												7.41
SHELBY COUNTY SHERIFF	5,843.84				106,657.34											5,746.12	
SIMPSON COUNTY	755.87					86,030.17										730.87	
SMITHS GROVE CITY OF						498.66										8.32	
STATE OF KENTUCKY				488,490.77												86,548.29	
TAYLOR COUNTY						35,575.84											2,744.47
TODD COUNTY SHERIFF					8,425.53												139.89
TRIGG COUNTY SHERIFF					11,477.92												224.13
TRIPLE H AND B INVESTMENTS LLC	9,476.90		35,781.22														
WARREN COUNTY	14,393.26				147,886.49											-8,578.06	
WASHINGTON COUNTY SHERIFF					12,111.81											237.47	
WEBSTERS COUNTY SHERIFF					12,133.85											455.78	
WINGO CITY OF					1,107.30												72.37

Collector	MAR-17	APR-17	MAY-17	JUN-17	JUL-17	AUG-17	SEP-17	OCT-17
ANDERSON COUNTY SHERIFF								
BARREN COUNTY SHERIFF								
BOYLE COUNTY CLERK								
BRECKINRIDGE COUNTY SHERIFF								
BURGIN BOARD OF EDUCATION								
CALDWELL COUNTY SHERIFF								
CALHOUN CITY OF								
CAMPBELLSVILLE INDEPENDENT SCHOOL BRD								
CHRISTIAN COUNTY SHERIFF								
CITY OF ADAIRVILLE	35.60							
CITY OF AUBURN		31.89						
CITY OF BEAVER DAM								
CITY OF BOWLING GREEN KY								
CITY OF CADIZ								
CITY OF CALVERT CITY								
CITY OF CAMPBELLSVILLE	1,165.50							
CITY OF CAVE CITY								
CITY OF CENTRAL CITY								
CITY OF CLOVERPORT								
CITY OF CROFTON								
CITY OF DAWSON SPRINGS								
CITY OF EDDYVILLE								
CITY OF ELKTON								
CITY OF GLASGOW								
CITY OF GREENSBURG								
CITY OF GREENVILLE KY								
CITY OF HARDINSBURG								
CITY OF HARRODSBURG								
CITY OF HARTFORD								
CITY OF HOPKINSVILLE								
CITY OF HORSE CAVE								
CITY OF LEBANON								
CITY OF LIVERMORE								
CITY OF MADISONVILLE KY	2,449.58							
CITY OF MARION KY								
CITY OF MAYFIELD								
CITY OF MORTONS GAP								
CITY OF OWENSBORO				347,290.72				
CITY OF PADUCAH	1,766.13							
CITY OF PRINCETON KY								
CITY OF RUSSELLVILLE								
CITY OF SEBREE								
CITY OF SHELBYVILLE								
CITY OF SPRINGFIELD KY								
CITY OF STANFORD	26.86							
CRITTENDEN COUNTY SHERIFF	1,192.61							
DANVILLE BOARD OF EDUCATION								
DAVIESS COUNTY								
DIXON CITY OF								
EDMONSON COUNTY SHERIFF								
FORDSVILLE CITY OF								
FRANKLIN COUNTY								
FRANKLIN KENTUCKY CITY OF								
GARRARD COUNTY SHERIFF								
GRAND RIVERS CITY OF								
GRAVES COUNTY SHERIFF								
GRAYSON COUNTY SHERIFF								
GREEN COUNTY SHERIFF					2,081.54			
HANCOCK COUNTY SHERIFF								
HANSON CITY OF								
HART COUNTY								
HAWESVILLE CITY OF								
HENDERSON CITY OF	108.64							
HENDERSON COUNTY SHERIFF								

Collector	MAR-17	APR-17	MAY-17	JUN-17	JUL-17	AUG-17	SEP-17	OCT-17
HOPKINS COUNTY SHERIFF								
HUSTONVILLE CITY OF								
JEFFERSON COUNTY SHERIFF								
JUNCTION CITY CITY OF								
LAWRENCEBURG CITY OF								
LINCOLN COUNTY SHERIFF								
LIVINGSTON COUNTY SHERIFF								
LOGAN COUNTY SHERIFF								
LYON COUNTY SHERIFF		81.31						
MARION COUNTY SHERIFF								
MARSHALL COUNTY								
MCCRACKEN COUNTY			5,796.46					
MCLEAN COUNTY SHERIFF								
MERCER COUNTY								
MUHLENBERG COUNTY SHERIFF								
MUNFORDVILLE CITY OF								
NORTONVILLE CITY OF								
OHIO COUNTY								
PARK CITY CITY OF								
PERRYVILLE CITY OF								
POWDERLY CITY OF								
SACRAMENTO CITY OF								
SHELBY COUNTY SHERIFF								
SIMPSON COUNTY								
SMITHS GROVE CITY OF								
STATE OF KENTUCKY								
TAYLOR COUNTY								
TODD COUNTY SHERIFF								
TRIGG COUNTY SHERIFF								
TRIPLE H AND B INVESTMENTS LLC								
WARREN COUNTY								
WASHINGTON COUNTY SHERIFF								
WEBSTERS COUNTY SHERIFF								
WINGO CITY OF								

Tax Year 2016 Taxes Paid as of 10/31/17

Collector	SEP-16	OCT-16	NOV-16	DEC-16	JAN-17	FEB-17	MAR-17	APR-17	MAY-17	JUN-17	JUL-17	AUG-17	SEP-17	OCT-17
ANDERSON COUNTY SHERIFF								40,043.65						
BARREN COUNTY SHERIFF								94,887.79						
BOYLE COUNTY CLERK								52,428.75						
BRECKINRIDGE COUNTY SHERIFF								16,095.87						
BURGIN BOARD OF EDUCATION								5,730.25						
CALDWELL COUNTY SHERIFF								36,297.15						
CALHOUN CITY OF								801.91						
CAMPBELLSVILLE INDEPENDENT SCHOOL BRD												49,446.06		
CHRISTIAN COUNTY SHERIFF								200,912.29						
CITY OF ADAIRVILLE								1,062.79						
CITY OF AUBURN									3,867.29					
CITY OF BEAVER DAM								3,324.08						
CITY OF BOWLING GREEN KY		3,914.00						284,004.55						
CITY OF CADIZ								3,240.75						
CITY OF CALVERT CITY								3,680.68						
CITY OF CAMPBELLSVILLE								15,189.63						
CITY OF CAVE CITY								2,569.91						
CITY OF CLOVERPORT								2,408.48						
CITY OF CROFTON.								5,124.55						
CITY OF DAWSON SPRINGS											9,116.16			
CITY OF EDDYVILLE								2,294.72						
CITY OF ELKTON								2,898.95						
CITY OF GLASGOW								12,010.89						
CITY OF GREENSBURG									3,310.56					
CITY OF GREENVILLE KY								4,651.86						
CITY OF HARDINSBURG								3,992.28						
CITY OF HARRODSBURG								4,715.96						
CITY OF HARTFORD									3,650.83					
CITY OF HOPKINSVILLE								39,937.57						
CITY OF LEBANON								5,268.01						
CITY OF LIVERMORE								470.97						
CITY OF MADISONVILLE KY											13,772.96			
CITY OF MARION KY								5,865.01						
CITY OF MAYFIELD				5,510.00				68,960.98						
CITY OF MORTONS GAP												698.53		
CITY OF OWENSBORO										324,056.18				
CITY OF PADUCAH			1,945.34					204,510.21						
CITY OF PRINCETON KY								7,427.86						
CITY OF RUSSELLVILLE								6,820.26						
CITY OF SEBREE								2,101.19						
CITY OF SHELBYVILLE	1,496.00							65,598.23						
CITY OF SPRINGFIELD KY								2,109.47						
CITY OF WHITESVILLE									234.06					
CRITTENDEN COUNTY SHERIFF								18,642.48						
DANVILLE BOARD OF EDUCATION								90,142.11						
DAVIESS COUNTY								332,991.93						
DIXON CITY OF								234.14						
EDMONSON COUNTY SHERIFF								2,827.86						
FORDSVILLE CITY OF								385.29						

Tax Year 2016 Taxes Paid as of 10/31/17

Collector	SEP-16	OCT-16	NOV-16	DEC-16	JAN-17	FEB-17	MAR-17	APR-17	MAY-17	JUN-17	JUL-17	AUG-17	SEP-17	OCT-17
FRANKLIN COUNTY								5,931.32						
FRANKLIN KENTUCKY CITY OF	108.61							4,084.90						
GARRARD COUNTY SHERIFF								15,371.21						
GRAND RIVERS CITY OF								2,008.41						
GRAVES COUNTY SHERIFF							17,265.49	33,799.45						
GRAYSON COUNTY SHERIFF								112.22						
GREEN COUNTY SHERIFF								18,883.91						
HANCOCK COUNTY SHERIFF								12,618.57						
HART COUNTY									39,944.79					
HAWESVILLE CITY OF								3,065.25						
HOPKINS COUNTY SHERIFF											385,532.80			
JUNCTION CITY CITY OF								669.11						
LAWRENCEBURG CITY OF								4,349.25						
LIVINGSTON COUNTY SHERIFF								7,905.92						
LOGAN COUNTY SHERIFF								47,168.10						
LYON COUNTY SHERIFF								5,313.27						
MARION COUNTY SHERIFF								24,736.01						
MARSHALL COUNTY								19,498.39						
MCCRACKEN COUNTY			5,991.96						94,242.09					
MCLEAN COUNTY SHERIFF								15,515.68						
MERCER COUNTY								73,511.50						
MUHLENBERG COUNTY SHERIFF								45,758.08						
MUNFORDVILLE CITY OF									3,736.89					
NORTONVILLE CITY OF												1,177.52		
OHIO COUNTY								22,249.15						
PARK CITY CITY OF								583.54						
PERRYVILLE CITY OF								732.29						
POWDERLY CITY OF								1,334.81						
SACRAMENTO CITY OF								339.68						
SHELBY COUNTY SHERIFF		5,836.29						309,892.17						
SIMPSON COUNTY		760.41						54,382.33						
SLAUGHTERS CITY OF								167.26						
SMITHS GROVE CITY OF								505.10						
STATE OF KENTUCKY						519,135.13								
TAYLOR COUNTY								37,573.58						
TODD COUNTY SHERIFF									10,523.60					
TRIGG COUNTY SHERIFF								11,813.95						
TRIPLE H AND B INVESTMENTS LLC			45,753.11											
WARREN COUNTY		14,755.21						159,056.99						
WASHINGTON COUNTY SHERIFF								13,153.83						
WEBSTERS COUNTY SHERIFF								15,311.28						
WINGO CITY OF								1,146.26						

Tax Year 2017 Taxes Paid as of 10/31/17

Collector	OCT-17
CITY OF BOWLING GREEN KY	3,914.00
CITY OF SHELBYVILLE	1,496.00
CRITTENDEN COUNTY SHERIFF	152.29
FRANKLIN KENTUCKY CITY OF	110.70
GRAVES COUNTY SHERIFF	14,747.04
SHELBY COUNTY SHERIFF	5,890.19
WARREN COUNTY	14,685.22

Atmos Energy Corporation
Ad Valorem Tax
Fiscal 2016 through Fiscal 2017

Division	Division Description	Account	Account Description	Sub Account	Sub Account Description	Fiscal 2015	Fiscal 2016	Fiscal 2017	
009	Kentucky Division	4081	Taxes other than income taxes, utility operating income	30101	Ad Valorem - Accrual	5,587,056	4,997,055	4,447,056	Expense
						52,944	52,944	52,944	Capital
						5,640,000	5,049,999	4,500,000	Total KY Direct

Division	Division Description	Account	Account Description	Sub Account	Sub Account Description	Fiscal 2015	Fiscal 2016	Fiscal 2017	
091	KMD General Office	4081	Taxes other than income taxes, utility operating income	30101	Ad Valorem - Accrual	120,000	90,000	60,000	
					KY Allocation %	49.10%	52.22%	50.25%	
						58,920	46,998	30,150	Div 091 Allocation

Division	Division Description	Account	Account Description	Sub Account	Sub Account Description	Fiscal 2015	Fiscal 2016	Fiscal 2017	
002	SSU General Office	4081	Taxes other than income taxes, utility operating income	30101	Ad Valorem - Accrual	776,000	852,000	528,000	
					KY Allocation %	5.26%	5.35%	5.20%	
						40,818	45,582	27,456	Div 002 Allocation

Division	Division Description	Account	Account Description	Sub Account	Sub Account Description	Fiscal 2015	Fiscal 2016	Fiscal 2017	
012	SSU Customer Support	4081	Taxes other than income taxes, utility operating income	30101	Ad Valorem - Accrual	600,000	660,000	519,000	
					KY Allocation %	5.72%	5.70%	5.67%	
						34,320	37,620	29,427	Div 012 Allocation

	Fiscal 2015	Fiscal 2016	Fiscal 2017
Total Ad Valorem Expense Direct and Allocated to KY	5,721,114	5,127,255	4,534,089
Total Ad Valorem Capitalized to KY	52,944	52,944	52,944
Total Ad Valorem to KY	5,774,058	5,180,199	4,587,033

Atmos Energy Corporation
Kentucky Div 009 Gross Plant Balances
December 2014, December 2015, December 2016 and September 2017

	KY Div 009 Dec-14	KY Div 009 Dec-15	KY Div 009 Dec-16	KY Div 009 Sep-17
Property, Plant, Equipment				
Gas Plant in Service - Lp - Production Plant 1010-10001	(44,219)	(44,369)	(44,369)	(44,369)
Gas Plant in Service - Ng - Production Plant 1010-10002	680,353	44,369	44,369	44,369
Gas Plant in Service - Ng - Storage Plant 1010-10003	12,487,260	13,254,535	14,148,949	15,023,757
Gas Plant in Service - Transmission Plant 1010-10004	31,839,503	31,771,350	31,777,066	31,746,725
Gas Plant in Service - General Dist System Plant 1010-10006	381,622,957	413,302,792	472,849,306	507,225,381
Gas Plant in Service - General Plant 1010-10008	16,848,176	18,290,866	21,435,734	21,636,326
Gas plant acquisition adjustme - Acquisition Adj 1140-10017	3,278,547	3,278,547	3,278,547	3,278,547
Utility Plant	**446,712,578**	**479,898,090**	**543,489,602**	**578,910,737**
Construction Work in Progress	12,708,219	26,310,035	10,146,378	25,248,870
Total PP&E	**459,420,797**	**506,208,125**	**553,635,980**	**604,159,607**

EXHIBIT ____ (LK-14)

REQUEST:

Refer to Attachment 1 to the response to AG 1-24. Provide all support for the estimated 8% increase in ad valorem tax expense in 2018 compared to 2017, including all calculations and electronic spreadsheets in live format with formulas intact.

RESPONSE:

A standard estimated tax increase from year to year is 8%. The 8% adjustment, based upon a 3% tax rate and 5% valuation increase, is used as an estimate of year over year tax projections. Without additional knowledge of projected final valuations, Atmos Energy utilizes the 8% increase in many of our service areas (states). Since Kentucky historically has issued final assessments later in the year, we utilize an 8% increase in taxes until we have a better understanding of the potential increase to valuation and tax rates.

Respondent: Greg Waller

EXHIBIT ____ (LK-15)

REQUEST:

Provide a calculation of the rate or rates used to capitalize interest during construction for the three most recent calendar years. Explain each component entering into the calculation of the rate(s).

RESPONSE:

Please see Attachment 1 through Attachment 3.

ATTACHMENTS:

ATTACHMENT 1 - Atmos Energy Corporation, Staff_1-19_Att1 - AFUDC Computation Dec 14.xlsx, 9 Pages.

ATTACHMENT 2 - Atmos Energy Corporation, Staff_1-19_Att2 - AFUDC Computation Dec 15.xlsx, 9 Pages.

ATTACHMENT 3 - Atmos Energy Corporation, Staff_1-19_Att3 - AFUDC Computation Dec 16.xlsx, 9 Pages.

Respondents: Greg Waller and Joe Christian

Atmos Energy Corporation
Computation of AFUDC Rate
For the Month ended December 31, 2015
Per 18 CFR Part 201, Gas Plant Instructions, Components of construction costs, item 17.

Line No.	Description	Amounts	References
	(a)	(b)	(c)
1	**Formulae:**		
2			
3	Ai = s(S/W)+d(D/(D+P+C))(1-S/W)		
4			
5	Ae = [1-S/W][p(P/(D+P+C))+c(C/(D+P+C))]		
6			
7			
8	**Where:**		
9			
10	Ai = Gross allowance for borrowed funds used during construction rate.		
11	Ae = Allowance for other funds used during construction rate.		
12			
13	S = Average short-term debt.	$591,990,652	See Wp S
14	s = Short-term debt interest rate.	1.1586%	See Wp S
15	D = Long-term debt.	$2,455,388,136	[2]
16	d = Long-term debt interest rate.	5.41%	See Wp L Rate
17	P = Preferred stock	$0	
18	p = Preferred stock cost rate.	0.00%	
19	C = Common equity	$3,194,798,013	[2]
20	c = Common equity cost rate.	10.50%	[3]
21	W = Average balance in construction work in progress.	$230,859,697	See Wp W
22			
23			
24			
25	**Results: [1]**		
26			
27	Ai= 1.159%		
28			
29	Ae= 0.000%		
30			
31	A(i+e)= 1.159%		
32			
33			

[1] If the short-term debt balance (line 13) is greater than the average balance in construction work in progress only the short-term rate is indicated. (line 14)
[2] Actual Book Balances as of the end of the prior fiscal year.
[3] The predominant jurisdiction for Atmos is MidTX business unit.
The ROE authorized in the latest Mid-Tex rate case was 10.5%.

CASE NO. 2017-00349
ATTACHMENT 2
TO STAFF DR NO. 1-19

Atmos Energy Corporation - Utility Only
Computation of Commitment Fee Rate and Average Outstanding Balance
For the Period Ended September 30, 2016
(update with new budget projections each October - from B.Stroud)

Line No.	Description	MTD Daily Average Amount Outstanding [1]	Adjustments	Adjusted Average Amount Outstanding	Days In Month	Weighted Average	Interest Paid [1]	Admin costs & Commitment Fee Portion [1]	Total	Projected Annual Rate	Projected Annual Rate w/o Commitment Fees
	(a)	(b)	(c)	(d)			(e)	(f)	(g)	(h)	(i)
1	October-15	485,451,613		485,451,613	31	41,117,486	168,958	192,160	361,118	0.80%	0.41%
2	November-15	604,993,867		604,993,867	30	49,589,661	217,943	188,602	406,545	0.83%	0.44%
3	December-15	749,693,484		749,693,484	31	63,498,628	383,821	192,160	575,981	0.99%	0.60%
4	January-16	[redacted]		686,512,006	31	58,147,192	[redacted]	[redacted]	628,264	1.14%	[redacted]
5	February-16	[redacted]		627,815,145	29	49,744,916	[redacted]	[redacted]	558,131	1.14%	[redacted]
6	March-16	[redacted]		535,200,393	31	45,331,181	[redacted]	[redacted]	532,144	1.14%	[redacted]
7	April-16	[redacted]		427,353,379	30	35,028,965	[redacted]	[redacted]	451,319	1.14%	[redacted]
8	May-16	[redacted]		490,238,994	31	41,522,975	[redacted]	[redacted]	503,582	1.14%	[redacted]
9	June-16	[redacted]		577,689,530	30	47,351,601	[redacted]	[redacted]	662,118	1.39%	[redacted]
10	July-16	[redacted]		580,226,865	31	49,145,068	[redacted]	[redacted]	683,611	1.39%	[redacted]
11	August-16	[redacted]		630,079,748	31	53,367,410	[redacted]	[redacted]	725,834	1.39%	[redacted]
12	September-16	[redacted]		708,630,803	30	58,084,492	[redacted]	[redacted]	769,447	1.39%	[redacted]
13											
14	Monthly Average	$591,990,652		$591,990,652	366	$49,327,465	$4,573,521	$2,284,573	$6,858,095		
15											
16											
17	Calculated Interest & Commitment Fee Average Annual Rate						0.7727%	0.3860%		1.16%	

[1] Projected; STD Balance, Commitment Fees & Int Rates from Planning & Budget; Int Paid is calculated. Projected amts replaced by actuals as they become known.
Projections and actuals exclude offsetting ST investments and Int income.

EXHIBIT ____ (LK-16)

REQUEST:

1. Refer to Atmos's application, Filing Requirement ("FR") 16(1)(b)4, Atmos's present and proposed tariffs.

   a. Confirm that the only proposed changes to Atmos's tariffs are: increases in monthly base charges and rates per Met for all classes; an increase in the Research & Development ("R&D") Unit Charge; and the addition of the Annual Review Mechanism ("ARM") tariff.

   b. State whether the Commission's approval of Atmos's ARM tariff as proposed would cause the withdrawal of existing tariff sheets. If so, indicate which Atmos tariff sheets would no longer be necessary as a result of the implementation of the ARM tariff.

RESPONSE:

a) Confirm

b) If the Commission were to approve the Company's proposed ARM, the Company would propose to adjust Sheet Nos. 34 and 35 to remove the DSM Lost Sales Adjustment (DLSA) from its Demand-Side Management Program and Sheet Nos. 38 and 39 to remove the Pipe Replacement Program (PRP) as the PRP rates would be rolled into the respective customer classes.

Respondent: Mark Martin

EXHIBIT ____ (LK-17)

BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION
FRANKFORT, KENTUCKY

IN RE:

PETITION OF ATMOS ENERGY CORPORATION FOR APPROVAL OF ADJUSTMENT OF ITS RATES AND REVISED TARIFF	))))	**DOCKET NO. 2009-00354**

EARNEST B. NAPIER, P.E.

I. INTRODUCTION OF WITNESS

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Earnest B. Napier. I am Vice President Technical Services of the Kentucky/Mid-States Division of Atmos Energy Corporation ("Atmos Energy" or "Company"). My business address is 810 Crescent Centre Drive, Suite 600, Franklin, TN 37067-6226.

II. SUMMARY OF TESTIMONY

Q. PLEASE BRIEFLY SUMMARIZE THE TESTIMONY YOU INTEND TO GIVE IN THIS MATTER.

A. In my testimony, I will describe Atmos Energy's budgeting process for capital expenditures ("Capex"). My testimony will describe how the Company decides upon and prioritizes its capital expenditures. Specifically, I will discuss the Company's budget for capital expenditures relating to Kentucky for the test period and as forecast for future years. I will also describe the engineering and operational aspects of the Company's proposed Pipe Replacement Program ("PRP") by providing information on the history of the piping systems and a description of the proposed methodology the Company will use to manage the PRP.

FY2012.

Q. WHAT KEY NEEDS ARE MET THROUGH THIS PARTICULAR BUDGET?

A. System improvement, pipeline integrity, and system integrity investments focus on customer safety and system reliability and are our highest priorities for capital budgeting. The next priority is public improvements and state and local public works projects such as highway relocations. The next priority is customer growth. Atmos Energy continues to build good working relationships with developers, economic development boards, and growing communities to meet the needs of the customer and to accommodate customer growth on its system. Next in order of priority, a modern fleet of vehicles and equipment (backhoes, safety equipment, ditchers, first responder equipment, air compressors, welding machines, etc.) allows us to maintain our system and continue to provide a reliable level of service to our customers. To enhance the level of customer service provided in the field, we also continue to make investments in new technology. Technology is a strategic investment that will enable us to continue improving our business processes, hold down operating costs, and meet the changing expectations of our customers.

VII. PIPE REPLACEMENT PROGRAM ("PRP")

Q. PLEASE SUMMARIZE THE PROPOSED PRP.

A. As part of our effort to provide the safest, most reliable natural gas service, Atmos Energy has been replacing aging infrastructure for several years. All of the cast iron main in Kentucky has been removed from service as well as many miles of bare steel pipe. However, our system still contains approximately 250 miles of bare steel transmission and distribution mains as well as associated service lines, service risers, meters and appurtenances that present maintenance and risk issues for Atmos Energy and the public. Through its PRP Atmos proposes to replace all bare steel pipe in its system. Atmos Energy considers these facilities to be aging infrastructure in need of scheduled replacement. Atmos Energy plans to replace these facilities over a period of fifteen (15) years, beginning in April of 2011. The estimated cost of the total program is approximately $124 million. Annual capital investment is estimated at approximately $6.7 million in year one and assuming consistent rates of replacement will increase to approximately $10 million in year fifteen (15) of the PRP.

Q. WHY DOES ATMOS ENERGY NEED A PIPE REPLACEMENT PLAN?

A. As stated above, Atmos Energy's Kentucky gas system still contains approximately 250 miles of bare steel transmission and distribution mains along with the associated service lines, service risers, meters and appurtenances needed to deliver natural gas to our customers. Many of these facilities have reached the point in their service life where it is no longer cost effective to continue to repair due to accelerated corrosion rates. All of the bare steel pipe in the Kentucky system is at least fifty years old and some sections are approaching seventy-five years. Atmos Energy's PRP will improve public safety and reliability of service for our customers. Atmos Energy plans to use a well–planned, systematic approach to replacement that will reduce inconvenience to the public, require fewer unplanned disruptions to traffic for emergency repair, and improve coordination with local and state highway agencies. Public safety will be our highest objective and those pipe sections that need prompt attention will be given priority.

Q. PLEASE DESCRIBE THE PIPE REPLACEMENT COMPONENTS THAT ATMOS PROPOSES TO INCLUDE IN ITS PRP.

A. Atmos proposes to include in the PRP all of the planning, design, replacement construction, investment and retirement costs related to the replacement of the following categories of transmission and distribution main – bare steel (whether or not cathodically protected), cathodically unprotected coated steel, and ineffectively coated steel (whether or not cathodically protected). These facilities will hereinafter be collectively referred to as "bare steel main". Also, as part of the PRP Atmos proposes to include all of the planning, design, replacement

Q. HOW DID ATMOS ENERGY BUDGET ITS CAPITAL PROGRAM FOR BARE STEEL REPLACEMENT IN FISCAL YEAR 2010?

A. Specific replacement projects were identified and prioritized based on discussions with experienced operating and engineering personnel knowledgeable of the leakage rate and construction factors influencing public safety and reliability. A budget of approximately $13.1 million was developed for all system integrity projects. This amount includes bare steel main replacement, leak repair, service line, meter and meter set replacements and all other types of system integrity projects normally included in this budget category. The replacement budget includes finances for both planned projects and those main and service facilities requiring replacement on an emergency basis.

Q. WHAT IS THE EXPECTED BUDGET FOR THE PRP IN FUTURE YEARS?

A. Atmos Energy estimates it will spend approximately $124 million over a period of fifteen (15) years beginning in April 2011. Future projects and annual budgets will vary somewhat as we replace the highest priority bare steel pipe based on system condition and performance. While public safety and potential risk are always the primary considerations of project selection, the timing and extent of replacement cost recovery can impact the scope of replacement projects in any given year. Fair and timely investment recovery via the "PRP Rider," explained in Atmos Energy witness Smith's testimony, provides a critical and predictable base of capital to finance our PRP over approximately the next fifteen (15) years. The fiscal year 2012 capital replacement program will be the first full year of Atmos Energy's PRP. In the testimony of Atmos Energy witness Mr. Waller, he has described the timing of proposed annual filings related to the PRP.

Q. IN PLANNING THE PRP, WERE ALTERNATIVELY DEFINED LENGTHS OF THE PROGRAM CONSIDERED, AND WHY WAS A FIFTEEN YEAR PERIOD SELECTED?

A. Various program lengths were evaluated, but the duration of fifteen years was chosen because it matched the best combination of risk (the safe and reliable delivery of natural gas), and resources needs (internal/external labor, material,

EXHIBIT ____ (LK-18)

REQUEST:

Refer to the Waller Testimony, page 14, lines 18-26, and to Atmos's most recent Pipe Replacement Program ("PRP") rider rate proceeding, Case No. 2017-00308.[5]

a. Provide for the record in this proceeding a comparison of Atmos's original PRP investment as approved in Case No. 2009-00354[6] with actual annual experience with the PRP. The comparison should include the actual realized cost of projects, the factors causing unanticipated additions to the original program, and the reasons for the initial underestimation of cost upon which the Commission relied in approving the PRP over a period of 15 years.

b. Provide for the record in this proceeding an update to the Direct Testimony of Earnest B. Napier from Case No. 2009-00354 with regard to the replacement of remaining bare steel mains and appurtenances, and the anticipated cost per year for the remainder of the 15-year period.

c. Provide a discussion of how Atmos prioritizes annual replacements through the PRP.

d. Provide the number of leaks on Atmos's Kentucky system for each year since it began replacing pipe using the PRP.

e. Refer to Case No. 2017-00308, Atmos's September 26, 2017 response to Commission Staff's Informal Conference Memorandum Data Request, Item 1, and its response to the Attorney General's Second Request for Information, Item 1, which collectively show expected PRP rates through 2025 assuming no rate case activity. Provide a discussion of any safety issues that are likely to arise if Atmos's pipeline replacements and resulting cost recovery were to be extended over a longer period in order to alleviate the impact of higher-than-anticipated cost on its customers.

RESPONSE:

a) As stated in the Company's response in Case No. 2017-00308 to AG DR No. 1-01 subpart (b)iii, "The estimate referenced in Mr. Napier's testimony is no longer valid." The original estimate of $124 million (see page 13 of the Napier testimony in 2009-00354) provided for filing of the PRP program based on Atmos Energy construction procedures, comparative projects, and industry regulation that are now over 10 years old. Additionally, there were assumptions made within this original estimate that have proved to be incorrect in order to manage a program of this size. A few of the more significant differences relate to (1) the cost of service line and meter loop replacement; (2) the cost of Crossbore

Inspection Services; (3) the estimated engineering design, project management, and mapping cost associated with these replacement projects; (4) the underestimation of the cost of large diameter high-pressure and transmission lines within the program. In general, these construction cost were all estimated at $400k / mile and our actual cost for replacement has been approximately $628k / mile for distribution and range from $1,100k to $2,000k / mile for HPD/Transmission depending on the size of pipeline being installed. Please see part b of this response for the Company's actual and projected investment.

b) The PRP program started in FY11 for Atmos Energy with minimal pipe replacement occurring this first year and work being assigned and contracted using existing Master Service Agreements. Atmos Energy solicited bids for dedicated PRP Contractors and began filling internal PRP inspection positions during FY11 and FY12 as our PRP budget and spend necessitated the positions. Additionally, Atmos Energy created and assigned (2) internal construction crews in FY13 and FY14 as the program grew and logistical needs presented themselves for work on isolated projects.

Success of the program and the ability to stay on target with the original projected timeline has been accomplished while also including additional field-identification of bare-steel systems, the Lake City and Shelbyville pipe segments, replacement of aging and at-risk infrastructure such as regulator and metering stations, inclusion of network and critical valves, and remote monitoring of pressure and flow at critical stations by Atmos Energy SCADA and measurement departments.

As provided in the Company's response to AG DR No. 1-01 subpart (b)iv and Staff DR No. 2-01 subpart (b) in Case No. 2017-00308, below is the estimated PRP spend for FY 2018 to 2025.

Year	Annual PRP Investment
2011	$3,741,125
2012	$17,300,344
2013	$17,171,794
2014	$22,691,182
2015	$36,926,441
2016	$29,968,709
2017	$39,898,050
2018 Est.	$44,900,000
2019 Est.	$51,100,000
2020 Est.	$56,900,000
2021 Est.	$63,200,000
2022 Est.	$63,100,000
2023 Est.	$70,700,000
2024 Est.	$79,200,000
2025 Est.	$88,700,000

c) PRP Program Management works continuously with local management and engineering to identify which bare steel projects will be scheduled for replacement each fiscal year. Based on approved capital dollars, filed annually with the Kentucky PSC, we plan projects according to many factors including:

- Analysis of recent leak surveys and leak history on remaining bare steel systems
- Recommendations by local SME and engineering on what would be the best use of capital for reduced O&M and system improvement
- Where contract crews, inspection, and warehouse materials are currently deployed and their ability to mobilize between separate locations
- The local impact to city and municipality based on local resources needed to support (locating, planning and zoning inspection, local plans for street overlay / downtown revitalization, and logistical issues such as availability of asphalt for street repairs, etc.)

There are some outside factors which may cause us to delay PRP projects into later years. The ability/difficulty in getting easements from landowners, construction that is weather sensitive such as the replacement of regulator stations and high-pressure pipelines, low pressure systems that require temporary feeds that (in turn) depend on a preceding project to be accomplished are examples.

d) In 2011, Atmos Energy was managing over 1,100 below ground leaks within the state of Kentucky. This number of leaks was on the increase as the program ramped up, peaking within the 2012-2013 operating years at over 1,300. Since this time, we have seen a significant decrease in the number of leaks found, monitored, and scheduled for repair. Atmos Energy currently has 530 leaks scheduled for repair (refer to the Company's response to Staff DR No. 2-01 subpart (c) in Case No. 2017-00308). Although reports will show slight variations based on timing scheduled leak surveys, our overall leak count continues to trend downward as infrastructure replacement continues.

It is important to note that the number of below ground leaks within the Atmos Energy distribution system continues to decline in spite of more stringent regulation, Atmos Energy O&M requirements, and newer leak survey technologies. Per the Atmos Energy DIM plan, we now leak survey all systems in Kentucky with bare steel annually. We have continuously invested in new infra-red and laser leak survey equipment that is able to detect methane at lower trace levels than before.

Date	# Leaks
Jan, 2011	1,127
Jan, 2012	1,308
Jan, 2013	1,354
Jan, 2014	1,169
Jan, 2015	1,076
Jan, 2016	677
Jan, 2017	600
Aug, 2017	528

e) Please see the Company's response to Staff DR No. 2-01 subpart (c) in Case No. 2017-00308.

Respondent: Mark Martin

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[5] Case No. 2017-00308, Electronic Application of Atmos Energy Corporation for PRP Rider Rates (Ky. PSC Oct. 27, 2017).
[6] Case No. 2009-00354, Application of Atmos Energy Corporation for an Adjustment of Rates (Ky. PSC May 28, 2010).

EXHIBIT ____ (LK-19)

BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION
FRANKFORT, KENTUCKY

IN RE:

PETITION OF ATMOS ENERGY CORPORATION FOR APPROVAL OF ADJUSTMENT OF ITS RATES AND REVISED TARIFF	))))	**DOCKET NO. 2009-00354**

EARNEST B. NAPIER, P.E.

I. INTRODUCTION OF WITNESS

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Earnest B. Napier. I am Vice President Technical Services of the Kentucky/Mid-States Division of Atmos Energy Corporation ("Atmos Energy" or "Company"). My business address is 810 Crescent Centre Drive, Suite 600, Franklin, TN 37067-6226.

II. SUMMARY OF TESTIMONY

Q. PLEASE BRIEFLY SUMMARIZE THE TESTIMONY YOU INTEND TO GIVE IN THIS MATTER.

A. In my testimony, I will describe Atmos Energy's budgeting process for capital expenditures ("Capex"). My testimony will describe how the Company decides upon and prioritizes its capital expenditures. Specifically, I will discuss the Company's budget for capital expenditures relating to Kentucky for the test period and as forecast for future years. I will also describe the engineering and operational aspects of the Company's proposed Pipe Replacement Program ("PRP") by providing information on the history of the piping systems and a description of the proposed methodology the Company will use to manage the PRP.

Q. WHAT STEPS WILL ATMOS ENERGY TAKE TO MAKE SURE THE NEW SYSTEM IS DESIGNED AND SIZED CORRECTLY FOR THE FUTURE?

A. Gas distribution systems are typically planned and designed on a minimum twenty-year horizon. Proper planning dictates that Atmos Energy look ahead for engineering and operational purposes as far as possible. The choice and size of replacement pipe will take into account the engineering and other requirements of system design. The PRP presents an opportunity to address pipe sizing issues with a system sized correctly for the current demands and future loads. Atmos Energy will utilize standard natural gas distribution engineering techniques to select the correct pipe size and type for the application.

Q. WHAT STEPS WILL ATMOS ENERGY TAKE TO ACHIEVE EFFICIENCIES AND REDUCE CONSTRUCTION COSTS?

A. The large scale projects resulting from Atmos' concentrated construction effort will allow us to leverage material purchases, obtain the best construction and restoration contractor costs, and acquire land and right-of-way, when needed, more cost effectively. Moreover, planning, designing and constructing regional and system wide facilities will allow Atmos to optimize both the facilities in place necessary to support gas service delivery as well as the size and configuration of the newly installed facilities. This approach will allow us to utilize best construction practices as they are implemented over a widespread part of our impacted distribution system to reduce construction costs and allow us to adopt and employ best operating and maintenance practices to reduce future O&M legacy costs.

Q. HOW WILL THE PRP AFFECT O&M EXPENSE?

A. Atmos Energy anticipates a significant reduction in leakage which, in turn, will impact operations and maintenance expense over the duration of the PRP. Many of the outstanding leaks in the system will be eliminated with the replacement of bare steel pipe. The elimination of leaking pipe and the risks and inconvenience due to emergency repair, will be the largest benefit for our customers.

EXHIBIT ____ (LK-20)

REQUEST:

Refer to page 21 lines 18 through 20 of Mr. Martin's Direct Testimony wherein he asks himself the question: "Does the proposed R&D unit charge increase create additional revenues for the Company?" and then answers that question with "No."

a. Confirm that the proposed increase in the R&D unit charge will result in increased revenues even though the Company plans to remit the increase in revenues to GTI.

b. Confirm that the Company's funding to GTI or a similar research organization is discretionary, i.e., there is no contractual or other obligation to increase funding to GTI compared to the amount presently recovered through the R&D rider.

RESPONSE:

a) Deny. Any funds collected through the R&D Rider are not booked as revenue to the Company. The proposed increase in the R&D unit charge is purely to match the spirit of the Order in Case No. 99-070, which was for the R&D unit charge to be $0.0174/Mcf by 2004.

b) Confirm. The Company's participation in a R&D funding program is purely voluntary. While there is no contract between the Company and GTI or a similar research organization, the initial goal of the R&D Rider was to mimic the contributions made by the interstate pipelines. The Company's R&D unit charge should have increased annually from 1999 to 2004. While one could argue that the Company's proposed R&D unit charge, which could have been billed and collected annually since 2004, is somewhat stale, the Company is purely seeking to increase its R&D unit charge to a previously approved level.

Respondent: Mark Martin