JOHN N. HUGHES

Attorney at Law

Professional service Corporation

124 West Todd Street

Frankfort, Kentucky 40601

Telephone: (502) 227-7270 **jnhughes@johnnhughespsc.com**

March 13, 2019

Gwen Pinson
Executive Director
Public Service Commission
211 Sower Blvd.
Frankfort, KY 40601

Re: Atmos Energy Corporation:
Case No. 2018-00281

Dear Ms. Pinson:

Atmos Energy Corporation submits its rebuttal testimony.

I certify that the electronic filing is a complete and accurate copy of the original documents to be filed in this matter, which will be filed within two days of this submission and that there are currently no parties in this proceeding that the Commission has excused from participation by electronic means.

If you have any questions about this matter, please contact me.

Very truly yours,

John N. Hughes

John N. Hughes

And

Mark R. Hutchinson
Wilson, Hutchinson and Littlepage
611 Frederica St.
Owensboro, KY 42301
270 926 5011
randy@whplawfirm.com

Attorneys for Atmos Energy Corporation

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF	)	
RATE APPLICATION OF	)	Case No. 2018-00281
ATMOS ENERGY CORPORATION	)	

CERTIFICATE AND AFFIDAVIT

The Affiant, Joe T. Christian, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared rebuttal testimony of this affiant in Case No. 2018-00281, in the Matter of the Rate Application of Atmos Energy Corporation, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared rebuttal testimony.

Joe T. Christian

STATE OF Texas

COUNTY OF Dallas

SUBSCRIBED AND SWORN to before me by Joe T. Christian on this the 11th day of March, 2019.

Notary Public

My Commission Expires: 9/1/2020

GISELLE R HEROY
Notary Public, State of Texas
Comm. Expires 09-01-2020
Notary ID 13080484-2

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF	)	
RATE APPLICATION OF	)	Case No. 2018-00281
ATMOS ENERGY CORPORATION	)	

CERTIFICATE AND AFFIDAVIT

The Affiant, Laura K. Gillham, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared rebuttal testimony of this affiant in Case No. 2018-00281, in the Matter of the Rate Application of Atmos Energy Corporation, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared rebuttal testimony.

Laura K. Gillham

Laura K. Gillham

STATE OF TEXAS

COUNTY OF DALLAS

SUBSCRIBED AND SWORN to before me by Laura K. Gillham on this the 12 day of March, 2019.

MARIA S. WILSON
Notary Public, State of Texas
Comm. Expires 05-25-2022
Notary ID 131582768

Notary Public

My Commission Expires: 5/25/22

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF	)	
RATE APPLICATION OF	)	Case No. 2018-00281
ATMOS ENERGY CORPORATION	)	

CERTIFICATE AND AFFIDAVIT

The Affiant, Mark A. Martin, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared rebuttal testimony of this affiant in Case No. 2018-00281, in the Matter of the Rate Application of Atmos Energy Corporation, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared rebuttal testimony.

Mark A. Martin

Mark A. Martin

STATE OF Kentucky

COUNTY OF Daviess

SUBSCRIBED AND SWORN to before me by Mark A. Martin on this the 5th day of March, 2019.

Joanne M. Henderson

Notary Public

My Commission Expires: Joanne M. Henderson
NOTARY PUBLIC
State at Large, Kentucky
ID # 596005
My Commission Expires 3/22/2022

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF	)	
RATE APPLICATION OF	)	Case No. 2018-00281
ATMOS ENERGY CORPORATION	)	

CERTIFICATE AND AFFIDAVIT

The Affiant, John S. McDill, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared rebuttal testimony of this affiant in Case No. 2018-00281, in the Matter of the Rate Application of Atmos Energy Corporation, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared rebuttal testimony.

John S McDill

John S. McDill

STATE OF Texas

COUNTY OF Dallas

SUBSCRIBED AND SWORN to before me by John S. McDill on this the 11 day of March, 2019.

NOTARY PUBLIC STATE OF TEXAS
Wendy M Brooks
Notary Public
State of Texas
My Comm. Exp. 3/31/22
Notary ID 12564029-8

Wendy M. Brooks

Notary Public

My Commission Expires: 3/31/22

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF	)	
RATE APPLICATION OF	)	Case No. 2018-00281
ATMOS ENERGY CORPORATION	)	

CERTIFICATE AND AFFIDAVIT

The Affiant, Gregory W. Smith, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared rebuttal testimony of this affiant in Case No. 2018-00281, in the Matter of the Rate Application of Atmos Energy Corporation, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared rebuttal testimony.

Gregory W. Smith

STATE OF Tennessee

COUNTY OF Williamson

SUBSCRIBED AND SWORN to before me by Gregory W. Smith on this the 5th day of March, 2019.

Pamela Pleasant

Notary Public

My Commission Expires: March 3, 2020

PAMELA PLEASANT STATE OF TENNESSEE NOTARY PUBLIC DAVIDSON COUNTY, TENN.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF	)	
RATE APPLICATION OF	)	Case No. 2018-00281
ATMOS ENERGY CORPORATION	)	

CERTIFICATE AND AFFIDAVIT

The Affiant, James H. Vander Weide, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared rebuttal testimony of this affiant in Case No. 2018-00281, in the Matter of the Rate Application of Atmos Energy Corporation, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared rebuttal testimony.

James H. Vander Weide

James H. Vander Weide

STATE OF North Carolina

COUNTY OF Durham

SUBSCRIBED AND SWORN to before me by James H. Vander Weide on this the 6th day of March, 2019.

JUSTIN COUCH
Notary Public
Orange Co., North Carolina
My Commission Expires Nov. 7, 2022

Justin Couch

Notary Public

My Commission Expires: 11-7-22

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF	)	
RATE APPLICATION OF	)	Case No. 2018-00281
ATMOS ENERGY CORPORATION	)	

CERTIFICATE AND AFFIDAVIT

The Affiant, Gregory K. Waller, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared rebuttal testimony of this affiant in Case No. 2018-00281, in the Matter of the Rate Application of Atmos Energy Corporation, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared rebuttal testimony.

G K Waller

Gregory K. Waller

STATE OF Texas

COUNTY OF Dallas

SUBSCRIBED AND SWORN to before me by Gregory K. Waller on this the 8th day of March, 2019.

NOTARY PUBLIC
STATE OF TEXAS
STACY A HUGHES
Notary ID # 10602813
My Commission Expires
January 20, 2021

Stacy A. Hughes

Notary Public

My Commission Expires: Jan 20, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF	)	
RATE APPLICATION OF	)	Case No. 2018-00281
ATMOS ENERGY CORPORATION	)	

CERTIFICATE AND AFFIDAVIT

The Affiant, Dane A. Watson, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared rebuttal testimony of this affiant in Case No. 2018-00281, in the Matter of the Rate Application of Atmos Energy Corporation, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared rebuttal testimony.

Dane A. Watson

Dane A. Watson

STATE OF TEXAS

COUNTY OF COLLIN

SUBSCRIBED AND SWORN to before me by Dane A. Watson on this the 5th day of March, 2019.

Marilyn Pomales

Notary Public

My Commission Expires: 07/26/2021

Marilyn Pomales
Notary Public, State of Texas
Comm. Expires 07-26-2021
Notary ID 12862526-8

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY	)	
	)	
CORPORATION FOR AN ADJUSTMENT	)	**Case No. 2018-00281**
	)	
OF RATES AND TARIFF MODIFICATIONS	)	

REBUTTAL TESTIMONY OF MARK A. MARTIN

I. INTRODUCTION

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

A. My name is Mark A. Martin. I am Vice President - Rates and Regulatory Affairs for the Kentucky/Mid-States Division of Atmos Energy Corporation ("Atmos Energy" or the "Company"). My business address is 3275 Highland Pointe Drive, Owensboro, Kentucky, 42303.

Q. PLEASE BRIEFLY DESCRIBE YOUR CURRENT RESPONSIBILITIES, AND PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I am responsible for Rates and Regulatory Affairs matters in Kentucky. I graduated from Eastern Illinois University in 1995 with a degree in Accounting. I have been with United Cities Gas Company and subsequently Atmos Energy Corporation since September 1995. I have served in a variety of positions of increasing responsibility in both Gas Supply and Rates prior to assuming my current responsibility in 2007.

Q. HAVE YOU SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. HAVE YOU REVIEWED THE TESTIMONY OF THE OFFICE OF THE ATTORNEY GENERAL'S WITNESS LANE KOLLEN?

A. Yes.

II. <u>PURPOSE AND SUMMARY OF REBUTTAL TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to address the issues raised and the conclusions and recommendations made in the testimony of Mr. Kollen. My rebuttal testimony will focus on two aspects: (1) the termination of the Company's PRP Rider; and (2) the Company's proposed capital expenditures.

III. <u>TERMINATION OF PRP RIDER</u>

Q. PLEASE DESCRIBE MR. KOLLEN'S RECOMMENDATION RELATED TO THE PRP RIDER.

A. Mr. Kollen recommends that the Commission deny the Company's request to terminate the PRP Rider and to remove the Company's forecasted bare steel replacement costs from its forecasted revenue requirement.[1]

Q. WHAT IS THE RATIONALE FOR MR. KOLLEN'S RECOMMENDATION RELATED TO THE PRP RIDER?

A. Mr. Kollen erroneously concludes that the Company's proposal is non-compliant with the provisions of the Commission's Order in Case No. 2017-00349.

[1] Kollen Direct at 19.

Q. DO YOU AGREE WITH MR. KOLLEN'S CONCLUSIONS LEADING TO HIS OPPOSITION TO THE TERMINATION OF THE PRP RIDER?

A. No. Mr. Kollen's conclusions are based upon a false premise. Mr. Kollen interprets the Commission's order in Case No. 2017-00349 as requiring the Company to file for a PRP Rider based on actual spending subject to a $28 million cap in a historic 12-month period.[2] What Mr. Kollen fails to appreciate is that the statute in KY (KRS 278.192) permits the Company to file to recover prudently incurred investment, as described in the Direct Testimony of Company Witness Gregory Waller.[3]

Q. WHAT IS THE BASIS FOR MR. KOLLEN'S INTERPRETATION OF THE COMMISSION'S ORDER AND WHY DO YOU BELIEVE IT IS INCORRECT?

A. Mr. Kollen claims that "the Commission intentionally limited recovery of PRP costs to actual costs incurred in a historic test year and on a lagged recovery basis,"[4] however, he does not consider the context in which the Commission reached that decision. The Commission changed the PRP Rider "In order to remove any question as to the reasonableness of the ratepayer-funded PRP…"[5] The Company's proposal in this proceeding does not propose to recover costs through the ratepayer-funded PRP. There is no question as to the reasonableness of the PRP. Instead the

[2] Kollen Direct at 16-17.

[3] Waller Direct at 10.

[4] Kollen Direct at 19.

[5] Order in Case No. 2017-00349 at 42.

reasonableness of the cost of forecasted capital expenditures can be evaluated in the context of a base rate proceeding.

Q. WHY IS THIS DISTINCTION IMPORTANT?

A. The PRP Rider allowed PRP-related capital spending to be initially reflected in rates without the level of review provided by the traditional rate case process. However, KRS 278.192 allows for forward looking treatment in rate proceedings for the utilities regulated by the Public Service Commission and the Commission expressed no concerns about the use of budget estimates within the context of a base rate case. Utilities in Kentucky are free to file for forward-looking rate treatment as part of base rate cases.

Q. PLEASE EXPLAIN FURTHER.

A. While the Commission did revise the Company's PRP Rider in Case No. 2017-00349, and placed restrictions on the PRP Rider's future use, the Commission did not modify its normal rate case procedures. While Mr. Kollen's arguments may merit consideration if the Company sought to recover these expenses within the context of the PRP Rider on a forward-looking basis, since the Company is not using the PRP Rider as the PRP Rider is permissive, his arguments about the appropriate use of the PRP Rider are irrelevant. The proposed bare steel replacement work should be evaluated by the Commission within the context of this base rate proceeding, as would any other forecasted capital expenditure. If the forecasted work is prudent and reasonable, then the recovery of that investment should be approved.

Q. HAS THE COMPANY PROPOSED TO DO THE SAME AMOUNT OF BARE STEEL PIPELINE REPLACEMENT WORK THAN THE COMMISSION DEEMED REASONABLE IN ITS ORDER IN CASE NO. 2017-00349?

A. Yes. The Company is proposing the exact same amount ($28 million) of bare steel replacement that the Commission deemed reasonable in its order in Case No. 2017-00349.

Q. IS THERE ANY CONTROVERSY RELATING TO THE TIMING OF THE AMOUNT OF BARE STEEL PIPELINE WORK PROPOSED BY THE COMPANY?

A. No. There is no disagreement about the timeframe for completing the forecasted amount of bare steel pipeline work. As described by Company Witness Greg Smith in his direct testimony, the exact amount of bare steel replacement is being done in the exact same time frame as contemplated by the Commission in its order in Case No. 2017-00349 and the Company is on track to meet the timelines laid out by the Commission in that order.[6]

Q. IS THERE ANY CONTROVERSY RELATING TO THE PRUDENCY OF THE BARE STEEL PIPELINE WORK PROPOSED BY THE COMPANY?

A. There does not appear to be any disagreement about the prudency of these forecasted projects, as Mr. Kollen states in his testimony that the Company will be

[6] Smith Direct at 4.

able to recover these costs through the PRP Rider, which indicates that the proposed work is prudent.[7]

Q. IF THE CORRECT AMOUNT OF BARE STEEL PIPELINE WORK IS BEING DONE AT THE SAME TIME AS MR. KOLLEN THINKS IT SHOULD BE UNDERTAKEN, WHAT IS THE POINT OF MR. KOLLEN'S OBJECTIONS?

A. Mr. Kollen's objections do not relate to the amount, timing, or nature of the bare steel pipeline work proposed. Rather, Mr. Kollen's testimony interprets the Commission's decision in Case No. 2017-00349 to require the Company to invest capital to replace bare steel on a lagged basis.[8] As initially described in his direct testimony and as further described in his rebuttal testimony, Company Witness Gregory Waller explains why such lag, when experienced in the context of significant capital investment in excess of system depreciation is especially harmful.[9]

Q. WHY DON'T YOU INTERPRET THE COMMISSION'S ORDER IN CASE NO. 2017-00349 IN THE SAME MANNER AS MR. KOLLEN?

A. Mr. Kollen interprets the Commission's decision as mandating that the Company limit itself to replacing bare steel pipeline through 2027 on a lagged basis.[10] Such an order would be confiscatory. The Commission's order did not require use of the

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[7] Kollen Direct at 20.

[8] Kollen Direct at 16-18.

[9] Waller Direct at 11 and Waller Rebuttal at 7.

[10] Kollen Direct at 15-16.

PRP Rider, but merely modified the terms of its potential use. The PRP Rider has always been permissive.

As Mr. Kollen stated, "In every base rate proceeding, the Commission has the opportunity to retain or implement various behavioral incentives for the utility to control its capital expenditures..."[11] The Commission's decision in Case No. 2017-00349 expressed concern over the forecasting of bare steel pipeline replacement costs within the context of PRP Rider filings. In doing so, the Commission, through the requirement of a historic 12-month period, provided a behavioral incentive for the Company to cease using the PRP Rider for bare steel replacement projects and instead submit those projected expenses to the review of all parties in a base rate case, which the Company is now doing in the present case. Had the Company instead chosen to reflect these costs in its rates in a lagged manner without submitting to a full base rate case, it could have used the PRP Rider as modified by Case No. 2017-00349.

IV. PROPOSED NON-BARE STEEL CAPITAL EXPENDITURES

Q. HAS MR. KOLLEN PROPOSED AN ADJUSTMENT RELATED TO THE COMPANY'S PROPOSED CAPITAL EXPENDITURES IN THIS CASE?

A. Yes.

[11] Attorney General's Response to Atmos Energy's Data Request No. 7.

Q. PLEASE DESCRIBE MR. KOLLEN'S PROPOSED RECOMMENDATION RELATED TO THE COMPANY'S CAPITAL EXPENDITURES IN THIS CASE.

A. Mr. Kollen proposes that the Commission place a cap on the Company's non-bare steel capital expenditures by limiting them to "a reasonable amount based on the Company's most recent three-year actual [non-bare steel] expenditures...."[12]

Q. DOES THE COMPANY AGREE WITH MR. KOLLEN'S PROPOSED RECOMMENDATION RELATED TO THE COMPANY'S PROPOSED CAPITAL EXPENDITURES IN THIS CASE?

A. No. Mr. Kollen's proposal for non-bare steel capital expenditures is unsupported by precedent, and would represent improper ratemaking. Moreover, Mr. Kollen fails to acknowledge the national effort to replace aging infrastructure. While the Company is modernizing its systems to be more reliable and safe, other utilities, not just natural gas, are doing the same thing as well as communities that are looking to replace aging roads and bridges.[13] Also, infrastructure funding is a top priority of a large coalition of more than 34 groups and companies including the Kentucky Chamber, the Kentucky League of Cities, UPS, Kentucky Public Transportation Association, and many more.

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[12] Kollen Direct at 26.

[13] Please see HB 517 regarding increasing the gas tax to help fund needed infrastructure projects.

Q. PLEASE EXPLAIN WHY MR. KOLLEN'S PROPOSAL IS UNSUPPORTED BY PRECEDENT.

A. The Company is supposed to operate in a manner consistent with that of a prudent utility operator. Prudent and reasonable capital expenditures are not necessarily based upon or otherwise related to a prior three-year average but rather driven by the operational and safety needs of the gas distribution system.[14] For example, a change in regulations may require the Company to spend an amount far in excess of recent prior spending levels. Similarly, a natural disaster such as the Company experienced in its Louisiana Division in 2005 with hurricane Katrina could result in a need to deploy capital far in excess of recent prior spending levels. Additionally, system growth and line relocations can require capital spending regardless of prior years' spending levels. For Mr. Kollen to simply rely on a historical average for capital spending without considering the ever-changing needs or updates required to run a safe and reliable system is irresponsible and imprudent. Some of these changing needs and regulations are discussed by Company witnesses Greg Smith and John McDill.

[14] I would note that Mr. Kollen's expertise, as described in LK-1, indicates no operational or engineering expertise but only accounting and financial experience.

Q. SHOULD THE COMPANY'S PROPOSED NON-BARE STEEL CAPITAL EXPENDITURES BE CONTROLLED AS RECOMMENDED BY MR. KOLLEN?

A. No. Rather, and consistent with past practice at this Commission and the regulatory compact,[15] the Company should be limited to capital expenditures (both bare steel and non-bare steel) that are reasonable and prudent.

Q. WHAT IS THE EFFECT OF MR. KOLLEN'S RECOMMENDATION?

A. The effect is to put a price on safety. I strongly disagree that you can put a price, or a cap, on safety. The Company is committed to running a safe and reliable manner while also being prudent. As evidenced by Company Witness Greg Smith (Mr. Smith), the Company's leak history and lost and unaccounted for gas has drastically reduced since the Company accelerated the replacement of aging infrastructure. While the Company was under the impression that the Commission gave clear direction in Case No. 2014-00274 that pipe replacement programs were not limited to bare steel, the Order in Case No. 2017-00349 shifted the focus back to bare steel-only replacement of the Company's existing pipe replacement program. However, the Company has categories of pipe that need to be replaced other than bare steel. As discussed in more detail in Mr. Smith's rebuttal testimony[16], the Company has over 200 miles of outdated plastic pipe that needs to be replaced. A cap is never good rate-making policy if your focus is on safety and

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[15] When I refer to the "regulatory compact", I refer to utilities being given the opportunity to earn a reasonable rate of return in exchange for their accepting the obligation to provide regulated services.

[16] Smith Rebuttal at 14.

reliability due to the changing needs and regulations in a running a safe and reliable gas distribution system. Mr. Kollen likes to attempt to confuse the Commission without mentioning the safety aspect, but as Mr. Smith has pointed out, the Company is still on a 80-100 year rate of replacement cycle. Does the Commission really want 80-100 year old pipe in the ground? There have been enough incidents across the country that the answer should quite simply be no. While the safest system cannot fully insulate from the occurrence of an incident, it can drastically reduce the effects of an incident if one was to ever occur.

Q. DOES MR. KOLLEN AGREE THAT THE COMPANY SHOULD BE ALLOWED TO PROPOSE AND RECOVER CAPITAL INVESTMENT THAT IS REASONABLE AND PRUDENT?

A. No. Mr. Kollen stated that he "does not believe that is the appropriate standard."[17] Mr. Kollen admits that he made no assessment of whether any proposed project was unreasonable or imprudently proposed by the Company, and instead simply proposes to reject any proposed capital expenditure that exceeds the Company's prior years' levels.[18] Mr. Kollen's suggestion is dangerous and imprudent. The Company values the Attorney General's role as a watchdog for consumers, however the Commission cannot fulfill its obligations to support safe and reliable service by following Mr. Kollen's recommendations related to the Company's capital spending. Mr. Kollen's recommendations need to be firmly rejected.

[17] Attorney General's Response to Atmos Energy's Data Request No. 11.
[18] *Id*.

Q. CAN THE COMPANY CONTROL ITS CAPITAL EXPENDITURES IN THE MANNER PRPOSED BY MR. KOLLEN?

A. No, to predetermine a limit on capital expenditures would potentially prevent the Company from fulfilling its obligation to operate its system prudently. As described by Mr. Greg Smith, the Company has identified a number of projects that it believes are prudent and provide safety and reliability benefits to its system and its customers.[19] Also, as I mentioned previously, events outside the Company's control, such as regulation, natural disasters, system growth, and line relocations can require capital spending.

Q. WHAT IS THE IMPACT OF THE AMOUNT OF CAPITAL EXPENDITURES THAT MR. KOLLEN IS PROPOSING TO DISALLOW?

A. Mr. Kollen testifies that he calculates his adjustment to result in a reduction to the base revenue requirement of $3.207 million.[20] That translates to an average of approximately $1.50 per monthly bill in Kentucky.[21] The Company believes that undertaking the projects proposed in its base rate case is prudent because they replace aging infrastructure and therefore result in a safer, more reliable system than would otherwise be available without the capital investment, thus provides a benefit to our customers. Mr. Kollen has offered no evidence to rebut this contention. He has placed no value on the safety enhancements proposed by the Company and

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[19] *See, e.g.*, Rebuttal Testimony of Greg Smith at 12-18 and 21.

[20] Kollen at 26.

[21] This calculation simply involved dividing the base revenue requirement of $3.207 million by the number of monthly bills in Kentucky. Due to class cost of service allocations, the actual impact on residential customers would be less and the actual impact on commercial and industrial customers would be greater.

believes that because the Company has been able to meet all of its safety and integrity concerns based on its historic capital expenditures, this somehow invalidates the Company's current proposals.[22]

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

[22] Attorney General's Response to Atmos Energy's Data Request Nos. 14 and 15.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES AND TARIFF MODIFICATIONS	)))))	**Case No. 2018-00281**

REBUTTAL TESTIMONY OF GREGORY K. WALLER

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, JOB TITLE AND BUSINESS ADDRESS.

A. My name is Gregory K. Waller. I am Manager, Rates and Regulatory Affairs with Atmos Energy Corporation ("Atmos Energy" or "Company"). My business address is 5420 LBJ Freeway, Ste. 1600, Dallas, Texas 75240.

Q. ARE YOU THE SAME GREGORY WALLER THAT FILED PREFILED TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to rebut the adjustments proposed by Attorney General's Office of Rate Intervention ("OAG") witness Mr. Lane Kollen for bare steel and non-bare steel capital investment in conjunction with the rebuttal testimony of Mr. Mark Martin, Mr. Greg Smith and Mr. John McDill. I will also rebut Mr. Kollen's proposed adjustment removing Construction Work in Progress ("CWIP") from rate base in conjunction with the rebuttal testimony of Mr. Joe Christian.

Q. HAVE YOU SUMMARIZED THE COMPANY'S REBUTTAL POSITION AND CALCULATED THE REVENUE REQUIREMENT THAT RESULTS?

A. Yes. The table below, which is adopted from the table that appears in Mr. Kollen's testimony on page 5, summarizes the Company's position on each of the OAG's adjustments. I calculated the resulting revenue requirement using the revenue requirement model attached to the response to Staff's Second Request, Item 64 and referenced below as the starting point. By simultaneously incorporating all of the adjustments, the proper revenue requirement can be calculated.

Atmos Energy Corporation - Kentucky Division
Summary of Company Rebuttal Positions
KPSC Case No. 2018-00281
Test Year Ended March 31, 2020

	Company Position	Rebuttal Witness(es)	Adjustment Amount
Atmos Requested Increase			
Atmos Request Based on Original Filing			$ 14,455,544
Atmos Corrections to State Tax Rate, Depreciation, and Other Provided in Staff 2-64	Accept	Waller	54,108
Atmos Adjusted Request Based on Response to Staff 2-64			$ 14,509,652
AG Operating Income Recommendations			
Adjust Depreciation Expense to Reflect ALG vs ELG Procedure	Reject	Watson, Waller[1]	
Remove Depreciation Expense Related to PRP After 9/30/18	Reject	Martin, Smith, McDill, Waller[2]	
Remove Ad Valorem Taxes Related to PRP After 9/30/18	Reject	Martin, Smith, McDill, Waller[2]	
Reduce Depreciation Expense Related to Reduction of Non-PRP Projected Plant	Reject	Martin, Smith, McDill, Waller[2]	
Reduce Ad Valorem Expense Related to Reduction of Non-PRP Projected Plant	Reject	Martin, Smith, McDill, Waller[2]	
AG Rate Base Recommendations			
Adjust Accumulated Depreciation and ADIT to Reflect ALG vs ELG Procedure	Reject	Watson, Waller[1]	
Remove PRP Plant Additions After 9/30/18	Reject	Martin, Smith, McDill, Waller[2]	
Reduce Projected Non-PRP Plant Based on Historic 3-Year Average	Reject	Martin, Smith, McDill, Waller[2]	
Remove CWIP in Rate Base	Reject	Waller	
Correct Cash Working Capital	Reject	Christian	
AG Rate of Return Recommendations			
Include Effects of October 4, 2018 Debt Issue on Capital Structure and Debt Rate	Modify	Christian	
Reduce Assumed Debt Rate for March 2019 Refinance	Modify	Christian	
Reflect Return on Equity of 9.70%	Reject	Vander Weide	
AG Composite Allocation Factor Recommendation	Reject	Gillham	
Total Impact of Rebuttal Positions Included in Exhibit GKW-R-1			$ (135,046)
Revenue Requirement in Exhibit GKW-R-1			$ 14,374,606

[1] The merits of the Company's proposed depreciation rates are supported by Watson. The impact on revenue requirement is supported by Waller in GKW-R-1.

[2] The merits of maintaining the Company's capital investment forecast are supported by all four witnesses. The impact on revenue requirement due to return and related operating income items is supported by Waller in GKW-R-1.

Q. DO YOU HAVE ANY EXHIBITS ATTACHED TO YOUR TESTIMONY?

A. Yes. Exhibit GKW-R-1 is the Company's revenue requirement model updated to account for the rebuttal positions of the Company's witnesses as summarized above.

Q. WAS THE EXHIBIT PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes.

II. <u>BARE STEEL AND NON-BARE STEEL CAPITAL INVESTMENT</u>

Q. DO YOU AGREE WITH MR. KOLLEN'S RECOMMENDATION TO LIMIT THE COMPANY'S CAPITAL INVESTMENT AND MODIFY THE RECOVERY MECHANISM ALLOWED BY STATUTE?

A. No.

Q. PLEASE EXPLAIN.

A. Mr. Kollen proposes to remove all of the Company's forecasted bare steel related investment and significantly reduce its non-bare steel related investment. He relies on his erroneous interpretation of the Commission's Order in Case No. 2017-00349 and his opinion as to the definition of "excessive" to make his recommendation. The Company, on the other hand, relies on its unyielding commitment to safety and the modernization of its distribution system. The Company emphatically reiterates that rate recovery methodologies that reduce or eliminate regulatory lag and therefore give the utility a reasonable opportunity to earn the fair rate of return authorized by the Commission are absolutely critical to delivering on that commitment. The Company adheres to the regulatory compact that its debt and equity investors are entitled to the opportunity to earn a fair rate of return on the capital that is prudently employed to provide safe and reliable utility service and customers are entitled to enjoy the benefits of safe and reliable service provided to them at a fair and reasonable rate.

Q. PLEASE EXPLAIN HOW THE COMPANY ARRIVED AT THE OVERALL LEVEL OF CAPITAL INVESTMENT THAT YOU INCLUDED IN YOUR FORWARD LOOKING TEST YEAR FORECAST?

A. The mechanics of the forecast are described in my pre-filed direct testimony beginning on page 7. The mechanics, however, are a small part of the answer to this question. The Company is committed to maintaining and enhancing the level of safety provided to its customers. The fulfillment of that commitment requires ongoing and systematic replacement of aging facilities at a rate higher than has been achieved in recent history. Increasing the rate of replacement, has, in turn required an accelerated level of capital investment. This trend is not unique to Atmos Energy but rather universal to virtually all natural gas distribution providers. The specific drivers of acceleration of investment are discussed at length in the rebuttal testimonies of Mr. Greg Smith and Mr. John McDill.

With this commitment to safety as its primary focus, the Company allocates available capital to each of the eight states in which it operates on a rolling five-year planning cycle. Once the level of capital available to each state is determined, based on the relative needs of each system and the cost recovery mechanisms in place, detailed work continues to develop the list and mix of projects that can be accomplished. In every case, there is more prudent replacement work possible than capital available in any given year. In recent years and in particular in Case No. 2017-00349, the Company proposed to accelerate the replacement of bare-steel pipe and related facilities which are the subject of the Company's PRP. Bare steel pipe generally ranks as the riskiest of the materials still in service in the Company's Kentucky system. The Company, however, believed that it was required to limit its PRP (bare steel) spending to $28 million as a result of the Commission's Order in Case No. 2017-00349. The Company's decision to hold capital expenditures constant but shift future expenditures between non-bare steel and bare steel categories is in response to the Company's compliance with that Order. The need for accelerated capital investment as a whole has not changed. In order to maintain and accelerate the pace of overall replacement of aging facilities in its Kentucky distribution system and address other non-bare steel materials, capital that could have been allocated to bare steel replacement was allocated to non-bare steel categories.

Q. HAVE YOU PREVIOUSLY HAD THE OPPORTUNITY TO ADDRESS THIS ISSUE BEFORE THE COMMISSION?

A. Yes. I testified before this Commission in Case No. 2017-00349 and described the capital allocation process summarized in the preceding question.[1]

Q. WHY DO RECOVERY MECHANISMS MATTER IN THE CAPITAL ALLOCATION PROCESS?

A. The attributes of the recovery mechanism(s) available to a utility in a particular jurisdiction determine the extent to which the utility truly has an opportunity to earn

[1] Case No. 2017-00349 Hearing video from approximately 4:23 - 4:29 (run time) which occurred from approximately 2:35 - 2:41 PM on March 22, 2018.

its authorized rate of return. As thoroughly explained in the direct and rebuttal testimonies of Mr. McDill, Smith and Martin, the Company will always invest in every jurisdiction at a level necessary to ensure safe and reliable service and is committed to making meaningful progress to accelerate the pace of replacement of aging infrastructure and modernization of its systems. The pace of that progress in any given jurisdiction is influenced by the level of allowed return combined with the mechanics of the rate recovery mechanism that determines the feasibility of achieving the allowed return. The Company must have both reasonable allowed returns and a reasonable opportunity of achieving those returns in order to continue to attract the level of capital required to modernize its distribution systems in a timely fashion. Obligating the Company to utilize historic looking treatment on a portion of its capital investment would not allow the Company the reasonable opportunity to earn its authorized rate of return.

Q. HOW IMPORTANT IS FORWARD LOOKING TREATMENT TO ENSURING THAT A UTILITY HAS A FEASIBLE CHANCE OF EARNING ITS AUTHORIZED RATE OF RETURN?

A. Forward looking treatment, which entails forecasting cost of service components and implementing rates such that the timing of the Company's revenues collected from customers aligns with the timing of its cost of service, is very important to providing the utility with a reasonable opportunity to earn its authorized return. With such treatment, regulators ensure that the rates customers are paying reflect the utility's cost of service and the value of investment provided during the same time period. KRS 278.192 allows for forward looking treatment in rate proceedings for the utilities regulated by the Commission. Atmos Energy's Kentucky rates have been set on a forward looking basis going back many years (at least since 1999) and were set on a forward looking basis in the Company's most recent rate case, Case No. 2017-00349.

Q. WHAT WOULD BE THE DISADVANTAGE OF ELIMINATING FORWARD LOOKING TREATMENT ON THE COMPANY'S INVESTMENT?

A. Eliminating forward looking treatment on any of the Company's investment would result in a regulatory construct that systematically prevents the Company from earning its authorized return due to the introduction of regulatory lag. If a Company must invest capital, experience depreciation on its investment, and support a given level of operating expenses in one time period but wait until a future time period to recover those costs, it cannot mathematically cover its total cost of service (including return) in a timely fashion. This is the definition of regulatory lag and it is especially harmful when a utility is in an era of increasing capital investment requirements (as is the case for virtually every public gas utility in America today). One need look no further than the summary table on page 5 of Mr. Kollen's testimony for an estimate of the cost of lag to the Company. The Company has a Board of Director (Board) approved capital budget and a five year plan in place today for capital investment in Kentucky and the Company will have executed the first 6 months of its fiscal 2019 budget as of the date of the hearing in this case with plans to meet the Board approved level of investment for the remainder of 2019 and 2020. Mr. Kollen has removed from ratemaking the return on some capital investment and related depreciation and ad valorem tax expense on investment that is used and useful prior to the date of the hearing. Furthermore, he removes additional return, depreciation and ad valorem expense on capital that the Company's Board has approved through the first half of fiscal 2020 and estimates the cost of that lag in his table of recommendations on page 5.

Q. DOES MR. KOLLEN'S TABLE OF RECOMMENDATIONS SHOW A COMPLETE VIEW OF THE IMPACT OF REGULATORY LAG?

A. No. Mr. Kollen's removal of PRP Plant Additions and Non-PRP capital and related expenses does not address the most detrimental aspect of lag which is related to stranded costs that are never recovered. The Company was asked whether or not it agreed that costs submitted under the rider would be recovered in less than one year if the Company had chosen to not withdraw the PRP Rider in part a. of the OAG's Second Request, Item 33. The Company's response was:

> "The Company disagrees. With an historic test year, some costs are never recovered. An historic test year results in a portion of the return on investment and depreciation being incurred prior to being reflected in rates. During the time between the day investment is placed in service and it being reflected in rates, the plant is subject to depreciation. Therefore every dollar invested in plant during an historic test year is included in rate base at less than one dollar by the time the test period concludes, the filing is made and rates are approved and implemented. The depreciation expense and return on investment associated with that timing lag is never recovered."

III. <u>CWIP IN RATE BASE</u>

Q. DO YOU AGREE WITH MR. KOLLEN'S RECOMMENDATION TO REMOVE CWIP FROM RATE BASE?

A. No.

Q. WHY NOT?

A. The level of CWIP in the Company's proposed rate base represents actual investment made by the Company as of June 30, 2018. Failure to include that investment in rate base is inconsistent with the concept of a future test year and would impose significant regulatory lag on the projects making up that CWIP balance.

Q. PLEASE EXPLAIN.

A. Take, for example, three large projects[2] that made up 69% of the $39.1 million of CWIP on June 30, 2018. Of the three projects, one is already in service and the other two are expected to be in service by the date of the hearing in this case. Once in service, they are not only used and useful but also subject to depreciation. Mr. Kollen's recommendation would deny the Company the opportunity to earn a return on this investment in this case - investment that is used and useful prior to the beginning of the forward looking test year <u>in this case</u>. Given the Company's plan to file annual forward looking test year cases, the earliest date from which it would begin to earn a return on this investment would be the subsequent forward looking test year which would begin on or about April 1, 2020. At that point the investment in question would be impaired by over a year of regulatory lag, making it mathematically impossible for the utility to earn its authorized return. This concept applies not only to the three specific projects listed but to all CWIP in the case. Specifically, any project in CWIP that is expected to close prior to the end of the forward looking test year in this case would experience regulatory lag under Mr.

[2] Marion to Fredonia ($16.5 million); Springfield Calvary ($6.7 million); Waddy Ph 2 ($4.0 million)

Kollen's recommendation. The only way to mitigate the introduction of lag on this level of CWIP, should the Commission be swayed by his arguments, would be to order the Company to implement Mr. Kollen's recommendation on a prospective basis and file its next general case accordingly. Alternatively, should the Commission wish to preserve its precedent in approving the inclusion of CWIP in rate base for the Company's rates, it could order the Company to cease the accrual of AFUDC for book purposes as a way to alleviate Mr. Kollen's concern on a prospective basis.

Q. IN ADDITION TO DENYING THE COMPANY A RETURN ON INVESTMENT, HAS MR. KOLLEN MADE ANY ERRORS IN HIS RECOMMENDATION?

A. Yes. Mr. Kollen recommends removal of the entirety of the CWIP balance in favor of AFUDC. His adjustment includes removal of CWIP for Shared Services assets on which no AFUDC is recorded and he fails to make an adjustment to AFUDC in its place. Thus, for this adjustment, Mr. Kollen recommends denial of return on investment AND denial of AFUDC which is clearly unreasonable.

Q. HAS THE COMPANY TREATED CWIP AND AFUDC IN THIS CASE IN A MANNER INDENTICAL TO PREVIOUS CASES FILED BEFORE THE COMMISSION?

A. Yes. Furthermore, Commission Orders in Case Nos. 2013-00148 and 2017-00349 specifically identified CWIP as a component of rate base approved by the Commission.[3]

Q. IS THIS THE FIRST TIME MR. KOLLEN HAS MADE THE RECOMMENDATION TO REMOVE CWIP FROM RATE BASE IN THE COMPANY'S KENTUCKY CASES?

A. Yes. Mr. Kollen has testified on behalf of the OAG in the Company's three most recent cases (including the instant case). In Case No 2015-00343, CWIP was $14.7 million and he made no proposal to remove it. In Case No. 2017-00349, CWIP was $27.5 million and he made no proposal to remove it. In the instant case, CWIP is $39.1 million and he is proposing to remove it from rate base. The calculation of and inclusion of CWIP in this case is exactly as in prior cases.

Q. IF CWIP WERE TO BE REMOVED FROM RATE BASE, SHOULD CAPITIAL STRUCTURE BE ADJUSTED TO REMOVE SHORT TERM DEBT AS A COMPONENT?

A. Yes. If the Company's investment in construction work in progress were to be disallowed, the appropriate capital structure for ratemaking purposes should exclude short term debt as a component. Please see the rebuttal testimony of Company witness Mr. Joe Christian for further discussion and argument.

[3] The Order in Case No. 2015-00343 approved a Settlement reached by the parties in which CWIP was a component of Rate Base.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

Allocation Factors

		Forecast Period			Base Period		
Line No.	Description	KY/ Md-Sts Division	Kentucky Jurisdiction	Kentucky Composite	KY/ Md-Sts Division	Kentucky Jurisdiction	Kentucky Composite
	Rate Base, Dep. Exp., & Taxes Other						
1	**Shared Services**						
2	General Office (Div 002)	10.40%	49.78%	5.18%	10.40%	49.78%	5.18%
3	Customer Support (Div 012)	10.95%	51.52%	5.64%	10.95%	51.52%	5.64%
4	**Kentucky/Mid-States**						
5	Mid-States General Office (Div 091)	100%	49.78%	49.78%	100%	49.78%	49.78%
6							
7							
8	**Greenville Avenue Data Center**			1.57%			1.57%
9	**Charles K. Vaughan Center**			2.32%			2.32%
10	**AEAM**			6.36%			6.36%
11	**ALGN**			0.00%			
12							
13	**Kentucky Composite Tax**			24.95%			
14							
15	**Rate of Return on Equity**			10.40%			
16							
17	**STDRATE**			3.40%			
18							
19	**LTDRATE**			4.56%			

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

Schedule	Pages	Description
A	1	Overall Financial Summary

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Overall Financial Summary
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:__X____Base Period___X____Forecasted Period — FR 16(8)(a)
Type of Filing:___X____Original________Updated ________Revised — Schedule A
Workpaper Reference No(s). — Witness: Waller

Line No.	Description	Supporting Schedule Reference	Base Jurisdictional Revenue Requirement	Forecasted Jurisdictional Revenue Requirement
	(a)	(b)	(c)	(d)
1	Rate Base	B-1	$ 414,053,383	$ 496,005,827
2	Adjusted Operating Income	C-1	$ 27,501,643	$ 27,529,780
3	Earned Rate of Return (line 2 divided by line 1)	J-1.1	6.64%	5.55%
4	Required Rate of Return	J-1	8.15%	7.93%
5	Required Operating Income (line 1 times line 4)	C-1	$ 33,745,351	$ 39,333,262
6	Operating Income Deficiency (line 5 minus line 2)	C-1	$ 6,243,708	$ 11,803,482
7	Gross Revenue Conversion Factor	H	1.34184	1.34184
8	**Revenue Deficiency (line 6 times line 7)**		**$ 8,378,050**	**$ 15,838,372**
9	Amortization of Excess ADIT	WP B.5 F1		(1,463,766)
10	**Revenue Increase Requested**	**C-1**		**$ 14,374,606**
11	Adjusted Operating Revenues	C-1		$ 169,717,866
12	Revenue Requirements (line 10 plus line 11)	C-1		$ 184,092,472

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

FR 16(8)(b) SCHEDULE B

Rate Base

Schedule	Pages	Description
B-1	2	Rate Base Summary
B-2	14	Plant in Service by Account and Sub Account
B-3	14	Accumulated Depreciation & Amortization
B-3.1	5	Depreciation Expense
B-4	2	Allowance for Working Capital
B-4.1	2	Working Capital Components - 13 Month Averages
B-4.2	2	Cash Working Capital - 1/8 O&M Expenses
B-5	2	Deferred Credits & Accumulated Deferred Income Taxes
B-6	2	Customer Advances For Construction

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Jurisdictional Rate Base Summary
as of December 31, 2018

Data:__X___Base Period______Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(b)1
Schedule B-1
Witness: Waller, Christian, Story

Line No.	Rate Base Component	Supporting Schedule Reference		Base Period Ending Balance		Base Period 13 Month Average
1	Plant in Service	B-2 B	$	671,307,963	$	632,311,605
2	Construction Work in Progress	B-2 B		39,130,198		36,163,305
3	Accumulated Depreciation and Amortization	B-3 B		(197,392,161)		(193,590,170)
4	Property Plant and Equipment, Net (Sum line 1 Thru 3)		$	513,046,001	$	474,884,740
5	Cash Working Capital Allowance	B-4.2 B	$	2,678,217	$	2,678,217
6	Other Working Capital Allowances (Inventory & Prepaids)	B-4.1 B		13,916,618		13,331,156
7	Customer Advances For Construction	B-6 B		(747,234)		(750,999)
8	Regulatory Assets / Liabilities*	WP B.5 F1; F.6		(34,046,196)		(34,757,594)
9	Deferred Inc. Taxes and Investment Tax Credits	B-5 B		(49,944,561)		(41,332,137)
10	Rate Base (Sum line 4 Thru 8)		$	444,902,845	$	414,053,383

Exhibit GKW-R-1
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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Jurisdictional Rate Base Summary
as of March 31, 2020

Data:______Base Period__X___Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(b)1
Schedule B-1
Witness: Waller, Christian, Story

Line No.	Rate Base Component	Supporting Schedule Reference		Forecasted Test Period Ending Balance			Forecasted Test Period 13 Month Average
1	Plant in Service	B-2 F	$	763,121,143		$	724,669,367
2	Construction Work in Progress	B-2 F		39,130,198			39,130,198
3	Accumulated Depreciation and Amortization	B-3 F		(199,412,545)			(194,453,459)
4	Property Plant and Equipment, Net (Sum Line 1 Thru 3)		$	602,838,796		$	569,346,106
5	Cash Working Capital Allowance	B-4.2 F	$	2,692,759		$	2,692,759
6	Other Working Capital Allowances (Inventory & Prepaids)	B-4.1 F		(1,652,038)			9,023,857
7	Customer Advances For Construction	B-6 F		(747,234)			(747,234)
8	Regulatory Assets / Liabilities	WP B.5 F1; F.6		(32,827,677)			(33,020,670)
9	Deferred Inc. Taxes and Investment Tax Credits	B-5 F		(54,145,487)	*		(51,288,991)
10	Rate Base (Sum Line 4 Thru 8)		$	516,159,118		$	496,005,827

**Test Period ending ADIT balance does not include forecasted change in NOLC.*
Forecasted change in NOLC is calculated on B.5F on a 13 month average basis only
and included in rate base and revenue requirement.

Exhibit GKW-R-1
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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Plant in Service by Accounts and SubAccounts
as of December 31, 2018

Data:__X___Base Period______Forecasted Period
Type of Filing:___X____Original_________Updated _________Revised
Workpaper Reference No(s).

FR 16(8)(b)2
Schedule B-2 B
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	12/31/2018 Ending Balance (a)	Adjustments (b)	Adjusted Balance (c) = (a) + (b)	Kentucky- Mid States Division Allocation (d)	Kentucky Jurisdiction Allocation (e)	Allocated Amount (f) = (c) * (d) * (e)	13 Month Average (g)	Kentucky- Mid States Division Allocation (h)	Kentucky Jurisdiction Allocation (i)	Allocated Amount (j) = (g) * (h) * (i)
		Kentucky Direct (Division 009)										
1		Intangible Plant										
2	30100	Organization	$ 8,330	$ -	$ 8,330	100%	100%	$ 8,330	$ 8,330	100%	100%	$ 8,330
3	30200	Franchises & Consents	$ 119,853	-	119,853	100%	100%	119,853	$ 119,853	100%	100%	119,853
4												
5		Total Intangible Plant	$ 128,182	$ -	$ 128,182			$ 128,182	$ 128,182			$ 128,182
6												
7		Natural Gas Production Plant										
8	32540	Rights of Ways	$ -	$ -	$ -	100%	100%	$ -	$ -	100%	100%	$ -
9	33202	Tributary Lines	$ -	-	-	100%	100%	-	$ -	100%	100%	-
10	33400	Field Meas. & Reg. Sta. Equip	$ -	-	-	100%	100%	-	$ -	100%	100%	-
11												
12		Total Natural Gas Production Plant	$ -	$ -	$ -			$ -	$ -			$ -
13												
14		Storage Plant										
15	35010	Land	$ 261,127	$ -	$ 261,127	100%	100%	$ 261,127	$ 261,127	100%	100%	$ 261,127
16	35020	Rights of Way	$ 4,682	-	4,682	100%	100%	4,682	$ 4,682	100%	100%	4,682
17	35100	Structures and Improvements	$ 17,916	-	17,916	100%	100%	17,916	$ 17,916	100%	100%	17,916
18	35102	Compression Station Equipment	$ 153,261	-	153,261	100%	100%	153,261	$ 153,261	100%	100%	153,261
19	35103	Meas. & Reg. Sta. Structues	$ 23,138	-	23,138	100%	100%	23,138	$ 23,138	100%	100%	23,138
20	35104	Other Structures	$ 137,443	-	137,443	100%	100%	137,443	$ 137,443	100%	100%	137,443
21	35200	Wells \ Rights of Way	$ 8,350,453	-	8,350,453	100%	100%	8,350,453	$ 8,351,816	100%	100%	8,351,816
22	35201	Well Construction	$ 1,699,999	-	1,699,999	100%	100%	1,699,999	$ 1,699,999	100%	100%	1,699,999
23	35202	Well Equipment	$ 449,309	-	449,309	100%	100%	449,309	$ 449,309	100%	100%	449,309
24	35203	Cushion Gas	$ 1,694,833	-	1,694,833	100%	100%	1,694,833	$ 1,694,833	100%	100%	1,694,833
25	35210	Leaseholds	$ 178,530	-	178,530	100%	100%	178,530	$ 178,530	100%	100%	178,530
26	35211	Storage Rights	$ 54,614	-	54,614	100%	100%	54,614	$ 54,614	100%	100%	54,614
27	35301	Field Lines	$ 175,350	-	175,350	100%	100%	175,350	$ 175,350	100%	100%	175,350
28	35302	Tributary Lines	$ 209,319	-	209,319	100%	100%	209,319	$ 209,319	100%	100%	209,319
29	35400	Compressor Station Equipment	$ 923,446	-	923,446	100%	100%	923,446	$ 923,446	100%	100%	923,446
30	35500	Meas & Reg. Equipment	$ 273,084	-	273,084	100%	100%	273,084	$ 273,084	100%	100%	273,084
31	35600	Purification Equipment	$ 414,663	-	414,663	100%	100%	414,663	$ 414,663	100%	100%	414,663
32												
33		Total Storage Plant	$ 15,021,168	$ -	$ 15,021,168			$ 15,021,168	$ 15,022,530			$ 15,022,530

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Plant in Service by Accounts and SubAccounts
as of December 31, 2018

Data:__X__Base Period______Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(b)2
Schedule B-2 B
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	12/31/2018 Ending Balance (a)	Adjustments (b)	Adjusted Balance (c) = (a) + (b)	Kentucky- Mid States Division Allocation (d)	Kentucky Jurisdiction Allocation (e)	Allocated Amount (f) = (c) * (d) * (e)	13 Month Average (g)	Kentucky- Mid States Division Allocation (h)	Kentucky Jurisdiction Allocation (i)	Allocated Amount (j) = (g) * (h) * (i)
34												
35		Transmission Plant										
36	36510	Land	$ 26,970	$ -	$ 26,970	100%	100%	$ 26,970	$ 26,970	100%	100%	$ 26,970
37	36520	Rights of Way	$ 867,772	-	867,772	100%	100%	867,772	$ 867,772	100%	100%	867,772
38	36602	Structures & Improvements	$ 49,002	-	49,002	100%	100%	49,002	$ 49,002	100%	100%	49,002
39	36603	Other Structues	$ 60,826	-	60,826	100%	100%	60,826	$ 60,826	100%	100%	60,826
40	36700	Mains Cathodic Protection	$ 139,638	-	139,638	100%	100%	139,638	$ 139,638	100%	100%	139,638
41	36701	Mains - Steel	$ 27,309,333	-	27,309,333	100%	100%	27,309,333	$ 27,350,977	100%	100%	27,350,977
42	36703	Mains - Anodes	$ -	-	-	100%	100%	-	$ -	100%	100%	-
43	36900	Meas. & Reg. Equipment	$ 731,467	-	731,467	100%	100%	731,467	$ 731,467	100%	100%	731,467
44	36901	Meas. & Reg. Equipment	$ 2,269,556	-	2,269,556	100%	100%	2,269,556	$ 2,269,556	100%	100%	2,269,556
45												
46		Total Transmission Plant	$ 31,454,564	$ -	$ 31,454,564			$ 31,454,564	$ 31,496,208			$ 31,496,208
47												
48		Distribution Plant										
49	37400	Land & Land Rights	$ 531,167	$ -	$ 531,167	100%	100%	$ 531,167	$ 531,167	100%	100%	$ 531,167
50	37401	Land	$ 37,326	-	37,326	100%	100%	37,326	$ 37,326	100%	100%	37,326
51	37402	Land Rights	$ 3,220,920	-	3,220,920	100%	100%	3,220,920	$ 2,910,064	100%	100%	2,910,064
52	37403	Land Other	$ 2,784	-	2,784	100%	100%	2,784	$ 2,784	100%	100%	2,784
53	37500	Structures & Improvements	$ 336,168	-	336,168	100%	100%	336,168	$ 336,168	100%	100%	336,168
54	37501	Structures & Improvements T.B.	$ 99,818	-	99,818	100%	100%	99,818	$ 99,818	100%	100%	99,818
55	37502	Land Rights	$ 46,264	-	46,264	100%	100%	46,264	$ 46,264	100%	100%	46,264
56	37503	Improvements	$ 4,005	-	4,005	100%	100%	4,005	$ 4,005	100%	100%	4,005
57	37600	Mains Cathodic Protection	$ 20,773,553	-	20,773,553	100%	100%	20,773,553	$ 20,885,551	100%	100%	20,885,551
58	37601	Mains - Steel	$ 162,648,385	-	162,648,385	100%	100%	162,648,385	$ 153,554,638	100%	100%	153,554,638
59	37602	Mains - Plastic	$ 120,588,439	-	120,588,439	100%	100%	120,588,439	$ 111,099,889	100%	100%	111,099,889
60	37603	Mains - Anodes	$ -	-	-	100%	100%	-	$ -	100%	100%	-
61	37604	Mains - Leak Clamps	$ -	-	-	100%	100%	-	$ -	100%	100%	-
62	37800	Meas & Reg. Sta. Equip - General	$ 22,159,380	-	22,159,380	100%	100%	22,159,380	$ 16,540,694	100%	100%	16,540,694
63	37900	Meas & Reg. Sta. Equip - City Gate	$ 4,601,452	-	4,601,452	100%	100%	4,601,452	$ 4,224,414	100%	100%	4,224,414
64	37905	Meas & Reg. Sta. Equipment T.b.	$ 1,652,259	-	1,652,259	100%	100%	1,652,259	$ 1,652,346	100%	100%	1,652,346
65	38000	Services	$ 137,018,701	-	137,018,701	100%	100%	137,018,701	$ 126,928,869	100%	100%	126,928,869
66	38100	Meters	$ 35,740,648	-	35,740,648	100%	100%	35,740,648	$ 33,508,206	100%	100%	33,508,206
67	38200	Meter Installaitons	$ 56,336,115	-	56,336,115	100%	100%	56,336,115	$ 55,805,624	100%	100%	55,805,624
68	38300	House Regulators	$ 11,948,457	-	11,948,457	100%	100%	11,948,457	$ 11,332,651	100%	100%	11,332,651
69	38400	House Reg. Installations	$ 231,142	-	231,142	100%	100%	231,142	$ 215,697	100%	100%	215,697
70	38500	Ind. Meas. & Reg. Sta. Equipment	$ 5,211,145	-	5,211,145	100%	100%	5,211,145	$ 5,190,260	100%	100%	5,190,260
71												
72		Total Distribution Plant	$ 583,188,126	$ -	$ 583,188,126			$ 583,188,126	$ 544,906,436			$ 544,906,436

Atmos Energy Corporation, Kentucky/Mid-States Division
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Plant in Service by Accounts and SubAccounts
as of December 31, 2018

Data:__X___Base Period______Forecasted Period
Type of Filing:___X____Original_________Updated _________Revised
Workpaper Reference No(s).

FR 16(8)(b)2
Schedule B-2 B
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	12/31/2018 Ending Balance	Adjustments	Adjusted Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	13 Month Average	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
			(a)	(b)	(c) = (a) + (b)	(d)	(e)	(f) = (c) * (d) * (e)	(g)	(h)	(i)	(j) = (g) * (h) * (i)
73												
74		General Plant **										
75	38900	Land & Land Rights	$ 1,211,697	$ -	$ 1,211,697	100%	100%	$ 1,211,697	$ 1,211,697	100%	100%	$ 1,211,697
76	39000	Structures & Improvements	$ 7,424,787	-	7,424,787	100%	100%	7,424,787	$ 7,286,005	100%	100%	7,286,005
77	39002	Structures-Brick	$ 173,115	-	173,115	100%	100%	173,115	$ 173,115	100%	100%	173,115
78	39003	Improvements	$ 709,199	-	709,199	100%	100%	709,199	$ 709,199	100%	100%	709,199
79	39004	Air Conditioning Equipment	$ 12,955	-	12,955	100%	100%	12,955	$ 12,955	100%	100%	12,955
80	39009	Improvement to leased Premises	$ 1,246,194	-	1,246,194	100%	100%	1,246,194	$ 1,246,194	100%	100%	1,246,194
81	39100	Office Furniture & Equipment	$ 1,814,260	-	1,814,260	100%	100%	1,814,260	$ 1,773,500	100%	100%	1,773,500
82	39103	Office Machines	$ -	-	-	100%	100%	-	$ -	100%	100%	-
83	39200	Transportation Equipment	$ 220,987	-	220,987	100%	100%	220,987	$ 220,987	100%	100%	220,987
84	39202	Trailers	$ -	-	-	100%	100%	-	$ -	100%	100%	-
85	39400	Tools, Shop & Garage Equipment	$ 3,714,892	-	3,714,892	100%	100%	3,714,892	$ 3,450,079	100%	100%	3,450,079
86	39603	Ditchers	$ 39,610	-	39,610	100%	100%	39,610	$ 39,610	100%	100%	39,610
87	39604	Backhoes	$ 62,747	-	62,747	100%	100%	62,747	$ 62,747	100%	100%	62,747
88	39605	Welders	$ 19,427	-	19,427	100%	100%	19,427	$ 19,427	100%	100%	19,427
89	39700	Communication Equipment	$ 524,257	-	524,257	100%	100%	524,257	$ 524,257	100%	100%	524,257
90	39701	Communication Equip.	$ -	-	-	100%	100%	-	$ -	100%	100%	-
91	39702	Communication Equip.	$ -	-	-	100%	100%	-	$ -	100%	100%	-
92	39705	Communication Equip. - Telemetering	$ -	-	-	100%	100%	-	$ -	100%	100%	-
93	39800	Miscellaneous Equipment	$ 3,891,771	-	3,891,771	100%	100%	3,891,771	$ 3,892,194	100%	100%	3,892,194
94	39901	Servers Hardware	$ 14,390	-	14,390	100%	100%	14,390	$ 14,390	100%	100%	14,390
95	39902	Servers Software	$ -	-	-	100%	100%	-	$ -	100%	100%	-
96	39903	Other Tangible Property - Network - H/W	$ 134,599	-	134,599	100%	100%	134,599	$ 134,599	100%	100%	134,599
97	39906	Other Tang. Property - PC Hardware	$ 730,409	-	730,409	100%	100%	730,409	$ 916,126	100%	100%	916,126
98	39907	Other Tang. Property - PC Software	$ -	-	-	100%	100%	-	$ -	100%	100%	-
99	39908	Other Tang. Property - Mainframe S/W	$ 123,515	-	123,515	100%	100%	123,515	$ 123,515	100%	100%	123,515
100												
101		Total General Plant	$ 22,068,811	$ -	$ 22,068,811			$ 22,068,811	$ 21,810,595			$ 21,810,595
102												
103		Total Plant (Div 9)	$ 651,860,851	$ -	$ 651,860,851			$ 651,860,851	$ 613,363,952			$ 613,363,952
104												
105		CWIP With out AFUDC	$ 38,154,809	$ -	$ 38,154,809	100%	100%	$ 38,154,809	$ 35,310,857	100%	100%	$ 35,310,857

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

FR 16(8)(b)2
Schedule B-2 B
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	12/31/2018 Ending Balance	Adjustments	Adjusted Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	13 Month Average	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
			(a)	(b)	(c) = (a) + (b)	(d)	(e)	(f) = (c) * (d) * (e)	(g)	(h)	(i)	(j) = (g) * (h) * (i)
106												
107		**Kentucky-Mid-States General Office (Division 091)**										
108												
109		Intangible Plant										
110	30100	Organization	$ 185,309	$ -	$ 185,309	100%	49.78%	$ 92,247	$ 185,309	100%	49.78%	92,247
111	30300	Misc Intangible Plant	$ 1,109,552	-	1,109,552	100%	49.78%	552,335	$ 1,109,552	100%	49.78%	552,335
112												
113		Total Intangible Plant	$ 1,294,861	$ -	$ 1,294,861			$ 644,582	$ 1,294,861			$ 644,582
114												
115		Distribution Plant										
116	37400	Land & Land Rights	$ -	$ -	$ -	100%	49.78%	$ -	$ -	100%	49.78%	$ -
117	35010	Land	-	-	-	100%	49.78%	-	-	100%	49.78%	-
118	37402	Land Rights	-	-	-	100%	49.78%	-	-	100%	49.78%	-
119	37403	Land Other	-	-	-	100%	49.78%	-	-	100%	49.78%	-
120	36602	Structures & Improvements	-	-	-	100%	49.78%	-	-	100%	49.78%	-
121	37402	Land Rights	-	-	-	100%	49.78%	-	-	100%	49.78%	-
122	37501	Structures & Improvements T.B.	-	-	-	100%	49.78%	-	-	100%	49.78%	-
123	37503	Improvements	-	-	-	100%	49.78%	-	-	100%	49.78%	-
124	36700	Mains Cathodic Protection	-	-	-	100%	49.78%	-	-	100%	49.78%	-
125	36701	Mains - Steel	-	-	-	100%	49.78%	-	-	100%	49.78%	-
126	37602	Mains - Plastic	-	-	-	100%	49.78%	-	-	100%	49.78%	-
127	37800	Meas & Reg. Sta. Equip - General	-	-	-	100%	49.78%	-	-	100%	49.78%	-
128	37900	Meas & Reg. Sta. Equip - City Gate	-	-	-	100%	49.78%	-	-	100%	49.78%	-
129	37905	Meas & Reg. Sta. Equipment T.b.	-	-	-	100%	49.78%	-	-	100%	49.78%	-
130	38000	Services	-	-	-	100%	49.78%	-	-	100%	49.78%	-
131	38100	Meters	-	-	-	100%	49.78%	-	-	100%	49.78%	-
132	38200	Meter Installaitons	-	-	-	100%	49.78%	-	-	100%	49.78%	-
133	38300	House Regulators	-	-	-	100%	49.78%	-	-	100%	49.78%	-
134	38400	House Reg. Installations	-	-	-	100%	49.78%	-	-	100%	49.78%	-
135	38500	Ind. Meas. & Reg. Sta. Equipment	-	-	-	100%	49.78%	-	-	100%	49.78%	-
136	38600	Other Prop. On Cust. Prem	-	-	-	100%	49.78%	-	-	100%	49.78%	-
137												
138		Total Distribution Plant	$ -	$ -	$ -			$ -	$ -			$ -

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Atmos Energy Corporation, Kentucky/Mid-States Division
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Data:__X___Base Period______Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(b)2
Schedule B-2 B
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	12/31/2018 Ending Balance (a)	Adjustments (b)	Adjusted Balance (c) = (a) + (b)	Kentucky- Mid States Division Allocation (d)	Kentucky Jurisdiction Allocation (e)	Allocated Amount (f) = (c) * (d) * (e)	13 Month Average (g)	Kentucky- Mid States Division Allocation (h)	Kentucky Jurisdiction Allocation (i)	Allocated Amount (j) = (g) * (h) * (i)
139												
140		General Plant										
141	39001	Structures Frame	$ 179,339	-	179,339	100%	49.78%	89,275	$ 179,339	100%	49.78%	89,275
142	39004	Air Conditioning Equipment	$ 15,384	-	15,384	100%	49.78%	7,658	$ 15,384	100%	49.78%	7,658
143	39009	Improvement to leased Premises	$ 38,834	-	38,834	100%	49.78%	19,332	$ 38,834	100%	49.78%	19,332
144	39100	Office Furniture & Equipment	$ 38,609	-	38,609	100%	49.78%	19,220	$ 39,253	100%	49.78%	19,540
145	39101	Office Furniture And	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
146	39103	Office Machines	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
147	39200	Transportation Equipment	$ 27,285	-	27,285	100%	49.78%	13,582	$ 27,285	100%	49.78%	13,582
148	39300	Stores Equipment	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
149	39400	Tools, Shop & Garage Equipment	$ 175,867	-	175,867	100%	49.78%	87,547	$ 175,867	100%	49.78%	87,547
150	39600	Power Operated Equipment	$ 20,516	-	20,516	100%	49.78%	10,213	$ 20,516	100%	49.78%	10,213
151	39700	Communication Equipment	$ 37,541	-	37,541	100%	49.78%	18,688	$ 37,541	100%	49.78%	18,688
152	39701	Communication Equip.	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
153	39702	Communication Equip.	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
154	39800	Miscellaneous Equipment	$ 814,167	-	814,167	100%	49.78%	405,292	$ 814,167	100%	49.78%	405,292
155	39900	Other Tangible Property	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
156	39901	Other Tangible Property - Servers - H/W	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
157	39902	Other Tangible Property - Servers - S/W	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
158	39903	Other Tangible Property - Network - H/W	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
159	39906	Other Tang. Property - PC Hardware	$ 70,178	-	70,178	100%	49.78%	34,934	$ 70,178	100%	49.78%	34,934
160	39907	Other Tang. Property - PC Software	$ 137,919	-	137,919	100%	49.78%	68,656	$ 88,807	100%	49.78%	44,208
161	39908	Other Tang. Property - Mainframe S/W	$ 828,509	-	828,509	100%	49.78%	412,432	$ 828,509	100%	49.78%	412,432
162												
163		Total General Plant	$ 2,384,148	$ -	$ 2,384,148			$ 1,186,829	$ 2,335,679			$ 1,162,701
164												
165		Total Plant (Div 91)	$ 3,679,009	$ -	$ 3,679,009			$ 1,831,410	$ 3,630,540			$ 1,807,283
166												
167		CWIP With out AFUDC	$ 4,642	$ -	$ 4,642	100%	49.78%	$ 2,311	$ 59,040	100%	49.78%	$ 29,390

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Atmos Energy Corporation, Kentucky/Mid-States Division
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Plant in Service by Accounts and SubAccounts
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Data:__X___Base Period______Forecasted Period
Type of Filing:___X____Original_________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(b)2
Schedule B-2 B
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	12/31/2018 Ending Balance (a)	Adjustments (b)	Adjusted Balance (c) = (a) + (b)	Kentucky- Mid States Division Allocation (d)	Kentucky Jurisdiction Allocation (e)	Allocated Amount (f) = (c) * (d) * (e)	13 Month Average (g)	Kentucky- Mid States Division Allocation (h)	Kentucky Jurisdiction Allocation (i)	Allocated Amount (j) = (g) * (h) * (i)
168												
169	**Shared Services General Office (Division 002)**											
170												
171		General Plant										
172	39000	Structures & Improvements	$ 1,586,282	$ -	$ 1,586,282	10.40%	49.78%	$ 82,124	$ 1,466,645	10.40%	49.78%	$ 75,930
173	39005	G-Structures & Improvements	$ 9,187,142	-	9,187,142	100.00%	1.57%	144,296	$ 9,187,158	100.00%	1.57%	144,296
174	39009	Improvement to leased Premises	$ 9,316,001	-	9,316,001	10.40%	49.78%	482,301	$ 9,316,001	10.40%	49.78%	482,301
175	39020	Struct & Improv AEAM	$ -	-	-	100.00%	6.36%	-	$ -	100.00%	6.36%	-
176	39029	Improv-Leased AEAM	$ 7,891	-	7,891	10.40%	6.36%	52	$ 2,772	10.40%	6.36%	18
177	39100	Office Furniture & Equipment	$ 5,144,630	-	5,144,630	10.40%	49.78%	266,344	$ 5,127,587	10.40%	49.78%	265,461
178	39102	Remittance Processing Equip	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
179	39103	Office Machines	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
180	39104	G-Office Furniture & Equip.	$ 104,316	-	104,316	100.00%	1.57%	1,638	$ 78,244	100.00%	1.57%	1,229
181	39120	Off Furn & Equip-AEAM	$ 263,338	-	263,338	100.00%	6.36%	16,754	$ 263,338	100.00%	6.36%	16,754
182	39200	Transportation Equipment	$ 7,125	-	7,125	10.40%	49.78%	369	$ 7,125	10.40%	49.78%	369
183	39300	Stores Equipment	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
184	39400	Tools, Shop & Garage Equipment	$ 76,071	-	76,071	10.40%	49.78%	3,938	$ 76,071	10.40%	49.78%	3,938
185	39420	Tools And Garage-AEAM	$ -	-	-	100.00%	6.36%	-	$ -	100.00%	6.36%	-
186	39500	Laboratory Equipment	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
187	39700	Communication Equipment	$ 1,039,344	-	1,039,344	10.40%	49.78%	53,808	$ 1,039,344	10.40%	49.78%	53,808
188	39720	Commun Equip AEAM	$ 8,824	-	8,824	100.00%	6.36%	561	$ 8,824	100.00%	6.36%	561
189	39800	Miscellaneous Equipment	$ 136,510	-	136,510	10.40%	49.78%	7,067	$ 136,510	10.40%	49.78%	7,067
190	39820	Misc Equip - AEAM	$ 7,388	-	7,388	100.00%	6.36%	470	$ 7,388	100.00%	6.36%	470
191	39900	Other Tangible Property	$ 162,075	-	162,075	10.40%	49.78%	8,391	$ 162,203	10.40%	49.78%	8,397
192	39901	Other Tangible Property - Servers - H/W	$ 39,780,343	-	39,780,343	10.40%	49.78%	2,059,476	$ 37,881,111	10.40%	49.78%	1,961,151
193	39902	Other Tangible Property - Servers - S/W	$ 22,284,605	-	22,284,605	10.40%	49.78%	1,153,701	$ 20,046,455	10.40%	49.78%	1,037,829
194	39903	Other Tangible Property - Network - H/W	$ 5,886,587	-	5,886,587	10.40%	49.78%	304,756	$ 4,287,497	10.40%	49.78%	221,969
195	39904	Other Tang. Property - CPU	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
196	39905	Other Tangible Property - MF - Hardware	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
197	39906	Other Tang. Property - PC Hardware	$ 2,537,000	-	2,537,000	10.40%	49.78%	131,344	$ 2,484,331	10.40%	49.78%	128,617
198	39907	Other Tang. Property - PC Software	$ 1,564,492	-	1,564,492	10.40%	49.78%	80,996	$ 1,504,611	10.40%	49.78%	77,895
199	39908	Other Tang. Property - Mainframe S/W	$ 70,884,071	-	70,884,071	10.40%	49.78%	3,669,753	$ 68,387,777	10.40%	49.78%	3,540,517
200	39909	Other Tang. Property - Application Software	$ 39,252	-	39,252	10.40%	49.78%	2,032	$ 39,252	10.40%	49.78%	2,032
201	39921	Servers-Hardware-AEAM	$ 1,628,900	-	1,628,900	100.00%	6.36%	103,635	$ 1,628,900	100.00%	6.36%	103,635
202	39922	Servers-Software-AEAM	$ 961,256	-	961,256	100.00%	6.36%	61,157	$ 961,256	100.00%	6.36%	61,157
203	39923	Network Hardware-AEAM	$ 60,170	-	60,170	100.00%	6.36%	3,828	$ 60,170	100.00%	6.36%	3,828
204	39924	39924-Oth Tang Prop - Gen.	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
205	39926	Pc Hardware-AEAM	$ 314,379	-	314,379	100.00%	6.36%	20,002	$ 314,379	100.00%	6.36%	20,002
206	39928	Application SW-AEAM	$ 20,716,774	-	20,716,774	100.00%	6.36%	1,318,052	$ 20,690,005	100.00%	6.36%	1,316,348
207	39931	ALGN-Servers-Hardware	$ 297,267	-	297,267	100.00%	0.00%	-	$ 297,267	100.00%	0.00%	-
208	39932	ALGN-Servers-Software	$ 345,730	-	345,730	100.00%	0.00%	-	$ 345,730	100.00%	0.00%	-
209	39938	ALGN-Application SW	$ 18,754,055	-	18,754,055	100.00%	0.00%	-	$ 17,976,336	100.00%	0.00%	-
210												
211		Total General Plant (Div 2)	$ 213,101,821	$ -	$ 213,101,821			$ 9,976,844	$ 203,784,289			$ 9,535,581
212												
213		CWIP With out AFUDC	$ 14,454,841	$ -	$ 14,454,841	10.40%	49.78%	$ 748,344	$ 12,321,402	10.40%	49.78%	$ 637,894
214												

Atmos Energy Corporation, Kentucky/Mid-States Division
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Data:__X___Base Period______Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(b)2
Schedule B-2 B
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	12/31/2018 Ending Balance	Adjustments	Adjusted Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	13 Month Average	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
			(a)	(b)	(c) = (a) + (b)	(d)	(e)	(f) = (c) * (d) * (e)	(g)	(h)	(i)	(j) = (g) * (h) * (i)
215	**Shared Services Customer Support (Division 012)**											
216												
217		General Plant										
218	38900	Land	$ 2,874,240	$ -	$ 2,874,240	10.95%	51.52%	$ 162,142	$ 2,874,240	10.95%	51.52%	$ 162,142
219	38910	CKV-Land & Land Rights	$ 1,886,443	-	1,886,442.92	100.00%	2.32%	43,739	$ 1,886,443	100.00%	2.32%	43,739
220	39000	Structures & Improvements	$ 12,669,003	-	12,669,002.61	10.95%	51.52%	714,686	$ 12,669,003	10.95%	51.52%	714,686
221	39009	Improvement to leased Premises	$ 2,820,614	-	2,820,613.55	10.95%	51.52%	159,117	$ 2,820,614	10.95%	51.52%	159,117
222	39010	CKV-Structures & Improvements	$ 12,305,840	-	12,305,840.00	100.00%	2.32%	285,325	$ 12,305,840	100.00%	2.32%	285,325
223	39100	Office Furniture & Equipment	$ 2,418,422	-	2,418,422.21	10.95%	51.52%	136,428	$ 2,389,011	10.95%	51.52%	134,769
224	39101	Office Furniture And	$ -	-	-	10.95%	51.52%	-	$ -	10.95%	51.52%	-
225	39102	Remittance Processing	$ -	-	-	10.95%	51.52%	-	$ -	10.95%	51.52%	-
226	39103	39103-Office Furn. - Copiers & Type	$ -	-	-	10.95%	51.52%	-	$ -	10.95%	51.52%	-
227	39110	CKV-Office Furn & Eq	$ 417,639	-	417,639.07	100.00%	2.32%	9,683	$ 395,234	100.00%	2.32%	9,164
228	39210	CKV-Transportation Eq	$ 96,290	-	96,290.22	100.00%	2.32%	2,233	$ 96,290	100.00%	2.32%	2,233
229	39410	CKV-Tools Shop Garage	$ 458,265	-	458,264.59	100.00%	2.32%	10,625	$ 419,762	100.00%	2.32%	9,733
230	39510	CKV-Laboratory Equip	$ 23,632	-	23,632.07	100.00%	2.32%	548	$ 23,632	100.00%	2.32%	548
231	39700	Communication Equipment	$ 1,913,117	-	1,913,117.11	10.95%	51.52%	107,923	$ 1,913,117	10.95%	51.52%	107,923
232	39710	CKV-Communication Equipment	$ 291,501	-	291,500.62	100.00%	2.32%	6,759	$ 291,501	100.00%	2.32%	6,759
233	39800	Miscellaneous Equipment	$ 70,016	-	70,015.66	10.95%	51.52%	3,950	$ 70,016	10.95%	51.52%	3,950
234	39810	CKV-Misc Equipment	$ 509,283	-	509,282.85	100.00%	2.32%	11,808	$ 509,283	100.00%	2.32%	11,808
235	39900	Other Tangible Property	$ 629,166	-	629,166.46	10.95%	51.52%	35,493	$ 629,166	10.95%	51.52%	35,493
236	39901	Other Tangible Property - Servers - H/W	$ 10,343,249	-	10,343,248.64	10.95%	51.52%	583,485	$ 10,343,249	10.95%	51.52%	583,485
237	39902	Other Tangible Property - Servers - S/W	$ 2,023,936	-	2,023,936.45	10.95%	51.52%	114,175	$ 2,023,936	10.95%	51.52%	114,175
238	39903	Other Tangible Property - Network - H/W	$ 629,226	-	629,225.62	10.95%	51.52%	35,496	$ 629,226	10.95%	51.52%	35,496
239	39906	Other Tang. Property - PC Hardware	$ 1,012,629	-	1,012,629.35	10.95%	51.52%	57,125	$ 1,003,829	10.95%	51.52%	56,628
240	39907	Other Tang. Property - PC Software	$ 190,247	-	190,246.97	10.95%	51.52%	10,732	$ 190,247	10.95%	51.52%	10,732
241	39908	Other Tang. Property - Mainframe S/W	$ 90,927,931	-	90,927,931.24	10.95%	51.52%	5,129,443	$ 90,401,789	10.95%	51.52%	5,099,762
242	39910	CKV-Other Tangible Property	$ 339,658	-	339,657.73	100.00%	2.32%	7,875	$ 339,658	100.00%	2.32%	7,875
243	39916	CKV-Oth Tang Prop-PC Hardware	$ 309,715	-	309,715.20	100.00%	2.32%	7,181	$ 274,366	100.00%	2.32%	6,361
244	39917	CKV-Oth Tang Prop-PC Software	$ 103,892	-	103,891.78	100.00%	2.32%	2,409	$ 103,892	100.00%	2.32%	2,409
245	39918	CKV-Oth Tang Prop-App	$ 20,560	-	20,560.16	100.00%	2.32%	477	$ 20,560	100.00%	2.32%	477
246	39924	Oth Tang Prop - Gen.	$ -	-	-	10.95%	51.52%	-	$ -	10.95%	51.52%	-
247												
248		Total General Plant (Div 12)	$ 145,284,513	$ -	$ 145,284,513			$ 7,638,858	$ 144,623,903			$ 7,604,789
249												
250		CWIP With out AFUDC	$ 3,983,794	$ -	$ 3,983,794	10.95%	51.52%	$ 224,734	$ 3,282,348	10.95%	51.52%	$ 185,164
251												
252		Total Plant (Div 009, 091, 002, 012)	$ 1,013,926,194	$ -	$ 1,013,926,194			$ 671,307,963	$ 965,402,683			$ 632,311,605
253												
254		Total CWIP Without AFUDC (Div 009, 091, 002, 012)	$ 56,598,085		$ 56,598,085			$ 39,130,198	$ 50,973,647			$ 36,163,305

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Plant in Service by Accounts and SubAccounts
as of March 31, 2020

Data:______Base Period__X___Forecasted Period
Type of Filing:__X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(b)2
Schedule B-2 F
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	3/31/2020 Ending Balance	Adjustments	Adjusted Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	13 Month Average	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
			(a)	(b)	(c) = (a) + (b)	(d)	(e)	(f) = (c) * (d) * (e)	(g)	(h)	(i)	(j) = (g) * (h) * (i)
		Kentucky Direct (Division 009)										
1		Intangible Plant										
2	30100	Organization	$ 8,330	$ -	$ 8,329.72	100%	100%	$ 8,330	$ 8,330	100%	100%	$ 8,329.72
3	30200	Franchises & Consents	$ 119,853	-	119,853	100%	100%	119,853	$ 119,853	100%	100%	119,853
4												
5		Total Intangible Plant	$ 128,182	$ -	$ 128,182			$ 128,182	$ 128,182			$ 128,182
6												
7		Natural Gas Production Plant										
8	32540	Rights of Ways	$ -	$ -	$ -	100%	100%	$ -	$ -	100%	100%	$ -
9	33202	Tributary Lines	$ -	-	-	100%	100%	-	$ -	100%	100%	-
10	33400	Field Meas. & Reg. Sta. Equip	$ -	-	-	100%	100%	-	$ -	100%	100%	-
11												
12		Total Natural Gas Production Plant	$ -	$ -	$ -			$ -	$ -			$ -
13												
14		Storage Plant										
15	35010	Land	$ 261,127	$ -	$ 261,126.69	100%	100%	$ 261,126.69	$ 261,127	100%	100%	$ 261,126.69
16	35020	Rights of Way	$ 4,682	-	4,682	100%	100%	4,682	$ 4,682	100%	100%	4,682
17	35100	Structures and Improvements	$ 17,916	-	17,916	100%	100%	17,916	$ 17,916	100%	100%	17,916
18	35102	Compression Station Equipment	$ 153,261	-	153,261	100%	100%	153,261	$ 153,261	100%	100%	153,261
19	35103	Meas. & Reg. Sta. Structues	$ 23,138	-	23,138	100%	100%	23,138	$ 23,138	100%	100%	23,138
20	35104	Other Structures	$ 137,443	-	137,443	100%	100%	137,443	$ 137,443	100%	100%	137,443
21	35200	Wells \ Rights of Way	$ 8,346,911	-	8,346,911	100%	100%	8,346,911	$ 8,348,396	100%	100%	8,348,396
22	35201	Well Construction	$ 1,699,999	-	1,699,999	100%	100%	1,699,999	$ 1,699,999	100%	100%	1,699,999
23	35202	Well Equipment	$ 449,309	-	449,309	100%	100%	449,309	$ 449,309	100%	100%	449,309
24	35203	Cushion Gas	$ 1,694,833	-	1,694,833	100%	100%	1,694,833	$ 1,694,833	100%	100%	1,694,833
25	35210	Leaseholds	$ 178,530	-	178,530	100%	100%	178,530	$ 178,530	100%	100%	178,530
26	35211	Storage Rights	$ 54,614	-	54,614	100%	100%	54,614	$ 54,614	100%	100%	54,614
27	35301	Field Lines	$ 175,350	-	175,350	100%	100%	175,350	$ 175,350	100%	100%	175,350
28	35302	Tributary Lines	$ 209,319	-	209,319	100%	100%	209,319	$ 209,319	100%	100%	209,319
29	35400	Compressor Station Equipment	$ 923,446	-	923,446	100%	100%	923,446	$ 923,446	100%	100%	923,446
30	35500	Meas & Reg. Equipment	$ 273,084	-	273,084	100%	100%	273,084	$ 273,084	100%	100%	273,084
31	35600	Purification Equipment	$ 414,663	-	414,663	100%	100%	414,663	$ 414,663	100%	100%	414,663
32												
33		Total Storage Plant	$ 15,017,626	$ -	$ 15,017,626			$ 15,017,626	$ 15,019,110			$ 15,019,110

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Plant in Service by Accounts and SubAccounts
as of March 31, 2020

Data:______Base Period__X___Forecasted Period
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Workpaper Reference No(s).

FR 16(8)(b)2
Schedule B-2 F
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	3/31/2020 Ending Balance	Adjustments	Adjusted Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	13 Month Average	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
			(a)	(b)	(c) = (a) + (b)	(d)	(e)	(f) = (c) * (d) * (e)	(g)	(h)	(i)	(j) = (g) * (h) * (i)
34												
35		Transmission Plant										
36	36510	Land	$ 26,970	$ -	$ 26,970.37	100%	100%	$ 26,970	$ 26,970	100%	100%	$ 26,970.37
37	36520	Rights of Way	$ 867,772	-	867,772	100%	100%	867,772	$ 867,772	100%	100%	867,772
38	36602	Structures & Improvements	$ 49,002	-	49,002	100%	100%	49,002	$ 49,002	100%	100%	49,002
39	36603	Other Structues	$ 60,826	-	60,826	100%	100%	60,826	$ 60,826	100%	100%	60,826
40	36700	Mains Cathodic Protection	$ 139,638	-	139,638	100%	100%	139,638	$ 139,638	100%	100%	139,638
41	36701	Mains - Steel	$ 26,859,142	-	26,859,142	100%	100%	26,859,142	$ 27,047,831	100%	100%	27,047,831
42	36703	Mains - Anodes	$ -	-	-	100%	100%	-	$ -	100%	100%	-
43	36900	Meas. & Reg. Equipment	$ 731,467	-	731,467	100%	100%	731,467	$ 731,467	100%	100%	731,467
44	36901	Meas. & Reg. Equipment	$ 2,269,556	-	2,269,556	100%	100%	2,269,556	$ 2,269,556	100%	100%	2,269,556
45												
46		Total Transmission Plant	$ 31,004,373	$ -	$ 31,004,373			$ 31,004,373	$ 31,193,061			$ 31,193,061
47												
48		Distribution Plant										
49	37400	Land & Land Rights	$ 531,167	$ -	$ 531,166.79	100%	100%	$ 531,167	$ 531,167	100%	100%	$ 531,166.79
50	37401	Land	$ 37,326	-	37,326	100%	100%	37,326	$ 37,326	100%	100%	37,326
51	37402	Land Rights	$ 3,952,286	-	3,952,286	100%	100%	3,952,286	$ 3,645,749	100%	100%	3,645,749
52	37403	Land Other	$ 2,784	-	2,784	100%	100%	2,784	$ 2,784	100%	100%	2,784
53	37500	Structures & Improvements	$ 336,168	-	336,168	100%	100%	336,168	$ 336,168	100%	100%	336,168
54	37501	Structures & Improvements T.B.	$ 99,818	-	99,818	100%	100%	99,818	$ 99,818	100%	100%	99,818
55	37502	Land Rights	$ 46,264	-	46,264	100%	100%	46,264	$ 46,264	100%	100%	46,264
56	37503	Improvements	$ 4,005	-	4,005	100%	100%	4,005	$ 4,005	100%	100%	4,005
57	37600	Mains Cathodic Protection	$ 20,494,641	-	20,494,641	100%	100%	20,494,641	$ 20,611,541	100%	100%	20,611,541
58	37601	Mains - Steel	$ 185,677,813	-	185,677,813	100%	100%	185,677,813	$ 176,025,498	100%	100%	176,025,498
59	37602	Mains - Plastic	$ 142,406,509	-	142,406,509	100%	100%	142,406,509	$ 133,261,910	100%	100%	133,261,910
60	37603	Mains - Anodes	$ -	-	-	100%	100%	-	$ -	100%	100%	-
61	37604	Mains - Leak Clamps	$ -	-	-	100%	100%	-	$ -	100%	100%	-
62	37800	Meas & Reg. Sta. Equip - General	$ 35,505,787	-	35,505,787	100%	100%	35,505,787	$ 29,911,913	100%	100%	29,911,913
63	37900	Meas & Reg. Sta. Equip - City Gate	$ 5,504,545	-	5,504,545	100%	100%	5,504,545	$ 5,126,032	100%	100%	5,126,032
64	37905	Meas & Reg. Sta. Equipment T.b.	$ 1,652,259	-	1,652,259	100%	100%	1,652,259	$ 1,652,259	100%	100%	1,652,259
65	38000	Services	$ 159,839,172	-	159,839,172	100%	100%	159,839,172	$ 150,274,437	100%	100%	150,274,437
66	38100	Meters	$ 40,873,233	-	40,873,233	100%	100%	40,873,233	$ 38,722,015	100%	100%	38,722,015
67	38200	Meter Installaitons	$ 57,594,641	-	57,594,641	100%	100%	57,594,641	$ 57,067,155	100%	100%	57,067,155
68	38300	House Regulators	$ 13,379,914	-	13,379,914	100%	100%	13,379,914	$ 12,779,948	100%	100%	12,779,948
69	38400	House Reg. Installations	$ 268,060	-	268,060	100%	100%	268,060	$ 252,587	100%	100%	252,587
70	38500	Ind. Meas. & Reg. Sta. Equipment	$ 5,262,616	-	5,262,616	100%	100%	5,262,616	$ 5,241,043	100%	100%	5,241,043
71												
72		Total Distribution Plant	$ 673,469,008	$ -	$ 673,469,008			$ 673,469,008	$ 635,629,619			$ 635,629,619

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Atmos Energy Corporation, Kentucky/Mid-States Division
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Plant in Service by Accounts and SubAccounts
as of March 31, 2020

Data:______Base Period__X___Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(b)2
Schedule B-2 F
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	3/31/2020 Ending Balance (a)	Adjustments (b)	Adjusted Balance (c) = (a) + (b)	Kentucky- Mid States Division Allocation (d)	Kentucky Jurisdiction Allocation (e)	Allocated Amount (f) = (c) * (d) * (e)	13 Month Average (g)	Kentucky- Mid States Division Allocation (h)	Kentucky Jurisdiction Allocation (i)	Allocated Amount (j) = (g) * (h) * (i)
73												
74		General Plant										
75	38900	Land & Land Rights	$ 1,211,697	$ -	$ 1,211,697.30	100%	100%	$ 1,211,697	$ 1,211,697	100%	100%	$ 1,211,697.30
76	39000	Structures & Improvements	$ 7,718,850	-	7,718,850	100%	100%	7,718,850	$ 7,595,600	100%	100%	7,595,600
77	39002	Structures-Brick	$ 173,115	-	173,115	100%	100%	173,115	$ 173,115	100%	100%	173,115
78	39003	Improvements	$ 709,199	-	709,199	100%	100%	709,199	$ 709,199	100%	100%	709,199
79	39004	Air Conditioning Equipment	$ 12,955	-	12,955	100%	100%	12,955	$ 12,955	100%	100%	12,955
80	39009	Improvement to leased Premises	$ 1,246,194	-	1,246,194	100%	100%	1,246,194	$ 1,246,194	100%	100%	1,246,194
81	39100	Office Furniture & Equipment	$ 1,903,399	-	1,903,399	100%	100%	1,903,399	$ 1,866,038	100%	100%	1,866,038
82	39103	Office Machines	$ -	-	-	100%	100%	-	$ -	100%	100%	-
83	39200	Transportation Equipment	$ 220,987	-	220,987	100%	100%	220,987	$ 220,987	100%	100%	220,987
84	39202	Trailers	$ -	-	-	100%	100%	-	$ -	100%	100%	-
85	39400	Tools, Shop & Garage Equipment	$ 4,340,624	-	4,340,624	100%	100%	4,340,624	$ 4,078,361	100%	100%	4,078,361
86	39603	Ditchers	$ 39,610	-	39,610	100%	100%	39,610	$ 39,610	100%	100%	39,610
87	39604	Backhoes	$ 62,747	-	62,747	100%	100%	62,747	$ 62,747	100%	100%	62,747
88	39605	Welders	$ 19,427	-	19,427	100%	100%	19,427	$ 19,427	100%	100%	19,427
89	39700	Communication Equipment	$ 524,257	-	524,257	100%	100%	524,257	$ 524,257	100%	100%	524,257
90	39701	Communication Equip.	$ -	-	-	100%	100%	-	$ -	100%	100%	-
91	39702	Communication Equip.	$ -	-	-	100%	100%	-	$ -	100%	100%	-
92	39705	Communication Equip. - Telemetering	$ -	-	-	100%	100%	-	$ -	100%	100%	-
93	39800	Miscellaneous Equipment	$ 3,891,771	-	3,891,771	100%	100%	3,891,771	$ 3,891,771	100%	100%	3,891,771
94	39901	Servers Hardware	$ 14,390	-	14,390	100%	100%	14,390	$ 14,390	100%	100%	14,390
95	39902	Servers Software	$ -	-	-	100%	100%	-	$ -	100%	100%	-
96	39903	Other Tangible Property - Network - H/W	$ 134,599	-	134,599	100%	100%	134,599	$ 134,599	100%	100%	134,599
97	39906	Other Tang. Property - PC Hardware	$ 268,136	-	268,136	100%	100%	268,136	$ 461,888	100%	100%	461,888
98	39907	Other Tang. Property - PC Software	$ -	-	-	100%	100%	-	$ -	100%	100%	-
99	39908	Other Tang. Property - Mainframe S/W	$ 123,515	-	123,515	100%	100%	123,515	$ 123,515	100%	100%	123,515
100												
101		Total General Plant	$ 22,615,472	$ -	$ 22,615,472			$ 22,615,472	$ 22,386,350			$ 22,386,350
102												
103		Total Plant (Div 9)	$ 742,234,661	$ -	$ 742,234,661			$ 742,234,661	$ 704,356,323			$ 704,356,323
104												
105		CWIP With out AFUDC	$ 38,154,809	$ -	$ 38,154,809	100%	100%	$ 38,154,809	$ 38,154,809	100%	100%	$ 38,154,809

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Plant in Service by Accounts and SubAccounts
as of March 31, 2020

Data:______Base Period__X___Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(b)2
Schedule B-2 F
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	3/31/2020 Ending Balance (a)	Adjustments (b)	Adjusted Balance (c) = (a) + (b)	Kentucky- Mid States Division Allocation (d)	Kentucky Jurisdiction Allocation (e)	Allocated Amount (f) = (c) * (d) * (e)	13 Month Average (g)	Kentucky- Mid States Division Allocation (h)	Kentucky Jurisdiction Allocation (i)	Allocated Amount (j) = (g) * (h) * (i)
106												
107	**Kentucky-Mid-States General Office (Division 091)**											
108												
109		Intangible Plant										
110	30100	Organization	$ 185,309	$ -	$ 185,309	100%	49.78%	$ 92,247	$ 185,309	100%	49.78%	$ 92,247
111	30300	Misc Intangible Plant	$ 1,109,552	-	1,109,552	100%	49.78%	552,335	$ 1,109,552	100%	49.78%	552,335
112												
113		Total Intangible Plant	$ 1,294,861	$ -	$ 1,294,861			$ 644,582	$ 1,294,861			$ 644,582
114												
115		Distribution Plant										
116	37400	Land & Land Rights	$ -	$ -	$ -	100%	49.78%	$ -	$ -	100%	49.78%	$ -
117	35010	Land	-	-	-	100%	49.78%	-	-	100%	49.78%	-
118	37402	Land Rights	-	-	-	100%	49.78%	-	-	100%	49.78%	-
119	37403	Land Other	-	-	-	100%	49.78%	-	-	100%	49.78%	-
120	36602	Structures & Improvements	-	-	-	100%	49.78%	-	-	100%	49.78%	-
121	37402	Land Rights	-	-	-	100%	49.78%	-	-	100%	49.78%	-
122	37501	Structures & Improvements T.B.	-	-	-	100%	49.78%	-	-	100%	49.78%	-
123	37503	Improvements	-	-	-	100%	49.78%	-	-	100%	49.78%	-
124	36700	Mains Cathodic Protection	-	-	-	100%	49.78%	-	-	100%	49.78%	-
125	36701	Mains - Steel	-	-	-	100%	49.78%	-	-	100%	49.78%	-
126	37602	Mains - Plastic	-	-	-	100%	49.78%	-	-	100%	49.78%	-
127	37800	Meas & Reg. Sta. Equip - General	-	-	-	100%	49.78%	-	-	100%	49.78%	-
128	37900	Meas & Reg. Sta. Equip - City Gate	-	-	-	100%	49.78%	-	-	100%	49.78%	-
129	37905	Meas & Reg. Sta. Equipment T.b.	-	-	-	100%	49.78%	-	-	100%	49.78%	-
130	38000	Services	-	-	-	100%	49.78%	-	-	100%	49.78%	-
131	38100	Meters	-	-	-	100%	49.78%	-	-	100%	49.78%	-
132	38200	Meter Installaitons	-	-	-	100%	49.78%	-	-	100%	49.78%	-
133	38300	House Regulators	-	-	-	100%	49.78%	-	-	100%	49.78%	-
134	38400	House Reg. Installations	-	-	-	100%	49.78%	-	-	100%	49.78%	-
135	38500	Ind. Meas. & Reg. Sta. Equipment	-	-	-	100%	49.78%	-	-	100%	49.78%	-
136	38600	Other Prop. On Cust. Prem	-	-	-	100%	49.78%	-	-	100%	49.78%	-
137												
138		Total Distribution Plant	$ -	$ -	$ -			$ -	$ -			$ -

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Plant in Service by Accounts and SubAccounts
as of March 31, 2020

Data:______Base Period__X___Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(b)2
Schedule B-2 F
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	3/31/2020 Ending Balance	Adjustments	Adjusted Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	13 Month Average	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
			(a)	(b)	(c) = (a) + (b)	(d)	(e)	(f) = (c) * (d) * (e)	(g)	(h)	(i)	(j) = (g) * (h) * (i)
139												
140		General Plant **										
141	39001	Structures Frame	$ 179,339	$ -	$ 179,339	100%	49.78%	$ 89,275	$ 179,339	100%	49.78%	$ 89,275
142	39004	Air Conditioning Equipment	$ 15,384	-	15,384	100%	49.78%	7,658	$ 15,384	100%	49.78%	7,658
143	39009	Improvement to leased Premises	$ 38,834	-	38,834	100%	49.78%	19,332	$ 38,834	100%	49.78%	19,332
144	39100	Office Furniture & Equipment	$ 38,609	-	38,609	100%	49.78%	19,220	$ 38,609	100%	49.78%	19,220
145	39101	Office Furniture And	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
146	39103	Office Machines	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
147	39200	Transportation Equipment	$ 27,285	-	27,285	100%	49.78%	13,582	$ 27,285	100%	49.78%	13,582
148	39300	Stores Equipment	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
149	39400	Tools, Shop & Garage Equipment	$ 175,867	-	175,867	100%	49.78%	87,547	$ 175,867	100%	49.78%	87,547
150	39600	Power Operated Equipment	$ 20,516	-	20,516	100%	49.78%	10,213	$ 20,516	100%	49.78%	10,213
151	39700	Communication Equipment	$ 37,541	-	37,541	100%	49.78%	18,688	$ 37,541	100%	49.78%	18,688
152	39701	Communication Equip.	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
153	39702	Communication Equip.	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
154	39800	Miscellaneous Equipment	$ 814,167	-	814,167	100%	49.78%	405,292	$ 814,167	100%	49.78%	405,292
155	39900	Other Tangible Property	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
156	39901	Other Tangible Property - Servers - H/W	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
157	39902	Other Tangible Property - Servers - S/W	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
158	39903	Other Tangible Property - Network - H/W	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
159	39906	Other Tang. Property - PC Hardware	$ 70,178	-	70,178	100%	49.78%	34,934	$ 70,178	100%	49.78%	34,934
160	39907	Other Tang. Property - PC Software	$ 197,253	-	197,253	100%	49.78%	98,192	$ 165,304	100%	49.78%	82,288
161	39908	Other Tang. Property - Mainframe S/W	$ 828,509	-	828,509	100%	49.78%	412,432	$ 828,509	100%	49.78%	412,432
162												
163		Total General Plant	$ 2,443,481	$ -	$ 2,443,481			$ 1,216,365	$ 2,411,532			$ 1,200,461
164												
165		Total Plant (Div 91)	$ 3,738,342	$ -	$ 3,738,342			$ 1,860,947	$ 3,706,393			$ 1,845,043
166												
167		CWIP With out AFUDC	$ 4,642	$ -	$ 4,642	100%	49.78%	$ 2,311	$ 4,642	100%	49.78%	$ 2,311

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Plant in Service by Accounts and SubAccounts
as of March 31, 2020

Data:______Base Period__X___Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(b)2
Schedule B-2 F
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	3/31/2020 Ending Balance (a)	Adjustments (b)	Adjusted Balance (c) = (a) + (b)	Kentucky- Mid States Division Allocation (d)	Kentucky Jurisdiction Allocation (e)	Allocated Amount (f) = (c) * (d) * (e)	13 Month Average (g)	Kentucky- Mid States Division Allocation (h)	Kentucky Jurisdiction Allocation (i)	Allocated Amount (j) = (g) * (h) * (i)
168												
169		**Shared Services General Office (Division 002)**										
170												
171		General Plant										
172	39000	Structures & Improvements	$ 1,906,438	$ -	$ 1,906,438	10.40%	49.78%	$ 98,699	$ 1,779,523	10.40%	49.78%	$ 92,128
173	39005	G-Structures & Improvements	$ 9,187,142	-	9,187,142	100.00%	1.57%	144,296	$ 9,187,142	100.00%	1.57%	144,296
174	39009	Improvement to leased Premises	$ 9,316,001	-	9,316,001	10.40%	49.78%	482,301	$ 9,316,001	10.40%	49.78%	482,301
175	39020	Struct & Improv AEAM	$ -	-	-	100.00%	6.36%	-	$ -	100.00%	6.36%	-
176	39029	Improv-Leased AEAM	$ 22,337	-	22,337	100.00%	6.36%	1,421	$ 16,610	100.00%	6.36%	1,057
177	39100	Office Furniture & Equipment	$ 5,191,908	-	5,191,908	10.40%	49.78%	268,791	$ 5,173,167	10.40%	49.78%	267,821
178	39102	Remittance Processing Equip	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
179	39103	Office Machines	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
180	39104	G-Office Furniture & Equip.	$ 178,594	-	178,594	100.00%	1.57%	2,805	$ 149,149	100.00%	1.57%	2,343
181	39120	Off Furn & Equip-AEAM	$ 263,338	-	263,338	100.00%	6.36%	16,754	$ 263,338	100.00%	6.36%	16,754
182	39200	Transportation Equipment	$ 7,125	-	7,125	10.40%	49.78%	369	$ 7,125	10.40%	49.78%	369
183	39300	Stores Equipment	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
184	39400	Tools, Shop & Garage Equipment	$ 76,071	-	76,071	10.40%	49.78%	3,938	$ 76,071	10.40%	49.78%	3,938
185	39420	Tools And Garage-AEAM	$ -	-	-	100.00%	6.36%	-	$ -	100.00%	6.36%	-
186	39500	Laboratory Equipment	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
187	39700	Communication Equipment	$ 1,039,344	-	1,039,344	10.40%	49.78%	53,808	$ 1,039,344	10.40%	49.78%	53,808
188	39720	Commun Equip AEAM	$ 8,824	-	8,824	100.00%	6.36%	561	$ 8,824	100.00%	6.36%	561
189	39800	Miscellaneous Equipment	$ 136,510	-	136,510	10.40%	49.78%	7,067	$ 136,510	10.40%	49.78%	7,067
190	39820	Misc Equip - AEAM	$ 7,388	-	7,388	100.00%	6.36%	470	$ 7,388	100.00%	6.36%	470
191	39900	Other Tangible Property	$ 161,644	-	161,644	10.40%	49.78%	8,369	$ 161,815	10.40%	49.78%	8,377
192	39901	Other Tangible Property - Servers - H/W	$ 44,862,780	-	44,862,780	10.40%	49.78%	2,322,600	$ 42,848,023	10.40%	49.78%	2,218,294
193	39902	Other Tangible Property - Servers - S/W	$ 28,287,161	-	28,287,161	10.40%	49.78%	1,464,460	$ 25,907,655	10.40%	49.78%	1,341,270
194	39903	Other Tangible Property - Network - H/W	$ 10,165,830	-	10,165,830	10.40%	49.78%	526,297	$ 8,469,471	10.40%	49.78%	438,475
195	39904	Other Tang. Property - CPU	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
196	39905	Other Tangible Property - MF - Hardware	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
197	39906	Other Tang. Property - PC Hardware	$ 2,681,536	-	2,681,536	10.40%	49.78%	138,826	$ 2,624,240	10.40%	49.78%	135,860
198	39907	Other Tang. Property - PC Software	$ 1,731,492	-	1,731,492	10.40%	49.78%	89,641	$ 1,665,291	10.40%	49.78%	86,214
199	39908	Other Tang. Property - Mainframe S/W	$ 77,600,897	-	77,600,897	10.40%	49.78%	4,017,492	$ 74,938,243	10.40%	49.78%	3,879,643
200	39909	Other Tang. Property - Application Software	$ 39,252	-	39,252	10.40%	49.78%	2,032	$ 39,252	10.40%	49.78%	2,032
201	39921	Servers-Hardware-AEAM	$ 1,628,900	-	1,628,900	100.00%	6.36%	103,635	$ 1,628,900	100.00%	6.36%	103,635
202	39922	Servers-Software-AEAM	$ 961,256	-	961,256	100.00%	6.36%	61,157	$ 961,256	100.00%	6.36%	61,157
203	39923	Network Hardware-AEAM	$ 60,170	-	60,170	100.00%	6.36%	3,828	$ 60,170	100.00%	6.36%	3,828
204	39924	39924-Oth Tang Prop - Gen.	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
205	39926	Pc Hardware-AEAM	$ 314,379	-	314,379	100.00%	6.36%	20,002	$ 314,379	100.00%	6.36%	20,002
206	39928	Application SW-AEAM	$ 20,791,579	-	20,791,579	100.00%	6.36%	1,322,811	$ 20,761,925	100.00%	6.36%	1,320,924
207	39931	ALGN-Servers-Hardware	$ 297,267	-	297,267	100.00%	0.00%	-	$ 297,267	100.00%	0.00%	-
208	39932	ALGN-Servers-Software	$ 345,730	-	345,730	100.00%	0.00%	-	$ 345,730	100.00%	0.00%	-
209	39938	ALGN-Application SW	$ 21,018,403	-	21,018,403	100.00%	0.00%	-	$ 20,120,780	100.00%	0.00%	-
210												
211		Total General Plant (Div 2)	$ 238,289,298	$ -	$ 238,289,298			$ 11,162,431	$ 228,304,590			$ 10,692,624
212												
213		CWIP With out AFUDC	$ 14,454,841	$ -	$ 14,454,841	10.40%	49.78%	$ 748,344	$ 14,454,841	10.40%	49.78%	$ 748,344

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Plant in Service by Accounts and SubAccounts
as of March 31, 2020

Data:______Base Period__X___Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(b)2
Schedule B-2 F
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	3/31/2020 Ending Balance	Adjustments	Adjusted Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	13 Month Average	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
			(a)	(b)	(c) = (a) + (b)	(d)	(e)	(f) = (c) * (d) * (e)	(g)	(h)	(i)	(j) = (g) * (h) * (i)
214												
215	**Shared Services Customer Support (Division 012)**											
216												
217		General Plant										
218	38900	Land	$ 2,874,240	$ -	$ 2,874,240	10.95%	51.52%	$ 162,142	$ 2,874,240	10.95%	51.52%	$ 162,142
219	38910	CKV-Land & Land Rights	$ 1,886,443	-	1,886,442.92	100.00%	2.32%	43,739	$ 1,886,443	100.00%	2.32%	43,739
220	39000	Structures & Improvements	$ 12,669,003	-	12,669,002.61	10.95%	51.52%	714,686	$ 12,669,003	10.95%	51.52%	714,686
221	39009	Improvement to leased Premises	$ 2,820,614	-	2,820,613.55	10.95%	51.52%	159,117	$ 2,820,614	10.95%	51.52%	159,117
222	39010	CKV-Structures & Improvements	$ 12,305,840	-	12,305,840.00	100.00%	2.32%	285,325	$ 12,305,840	100.00%	2.32%	285,325
223	39100	Office Furniture & Equipment	$ 2,601,912	-	2,601,911.94	10.95%	51.52%	146,780	$ 2,530,129	10.95%	51.52%	142,730
224	39101	Office Furniture And	$ -	-	-	10.95%	51.52%	-	$ -	10.95%	51.52%	-
225	39102	Remittance Processing	$ -	-	-	10.95%	51.52%	-	$ -	10.95%	51.52%	-
226	39103	39103-Office Furn. - Copiers & Type	$ -	-	-	10.95%	51.52%	-	$ -	10.95%	51.52%	-
227	39110	CKV-Office Furn & Eq	$ 579,053	-	579,053.49	100.00%	2.32%	13,426	$ 515,907	100.00%	2.32%	11,962
228	39210	CKV-Transportation Eq	$ 96,290	-	96,290.22	100.00%	2.32%	2,233	$ 96,290	100.00%	2.32%	2,233
229	39410	CKV-Tools Shop Garage	$ 703,898	-	703,898.10	100.00%	2.32%	16,321	$ 607,804	100.00%	2.32%	14,093
230	39510	CKV-Laboratory Equip	$ 23,632	-	23,632.07	100.00%	2.32%	548	$ 23,632	100.00%	2.32%	548
231	39700	Communication Equipment	$ 1,913,117	-	1,913,117.11	10.95%	51.52%	107,923	$ 1,913,117	10.95%	51.52%	107,923
232	39710	CKV-Communication Equipment	$ 291,501	-	291,500.62	100.00%	2.32%	6,759	$ 291,501	100.00%	2.32%	6,759
233	39800	Miscellaneous Equipment	$ 70,016	-	70,015.66	10.95%	51.52%	3,950	$ 70,016	10.95%	51.52%	3,950
234	39810	CKV-Misc Equipment	$ 509,283	-	509,282.85	100.00%	2.32%	11,808	$ 509,283	100.00%	2.32%	11,808
235	39900	Other Tangible Property	$ 629,166	-	629,166.46	10.95%	51.52%	35,493	$ 629,166	10.95%	51.52%	35,493
236	39901	Other Tangible Property - Servers - H/W	$ 10,343,249	-	10,343,248.64	10.95%	51.52%	583,485	$ 10,343,249	10.95%	51.52%	583,485
237	39902	Other Tangible Property - Servers - S/W	$ 2,023,936	-	2,023,936.45	10.95%	51.52%	114,175	$ 2,023,936	10.95%	51.52%	114,175
238	39903	Other Tangible Property - Network - H/W	$ 629,226	-	629,225.62	10.95%	51.52%	35,496	$ 629,226	10.95%	51.52%	35,496
239	39906	Other Tang. Property - PC Hardware	$ 1,068,705	-	1,068,704.82	10.95%	51.52%	60,288	$ 1,046,768	10.95%	51.52%	59,050
240	39907	Other Tang. Property - PC Software	$ 190,247	-	190,246.97	10.95%	51.52%	10,732	$ 190,247	10.95%	51.52%	10,732
241	39908	Other Tang. Property - Mainframe S/W	$ 94,401,847	-	94,401,846.65	10.95%	51.52%	5,325,414	$ 93,042,823	10.95%	51.52%	5,248,748
242	39910	CKV-Other Tangible Property	$ 339,658	-	339,657.73	100.00%	2.32%	7,875	$ 339,658	100.00%	2.32%	7,875
243	39916	CKV-Oth Tang Prop-PC Hardware	$ 539,317	-	539,316.64	100.00%	2.32%	12,505	$ 449,495	100.00%	2.32%	10,422
244	39917	CKV-Oth Tang Prop-PC Software	$ 103,892	-	103,891.78	100.00%	2.32%	2,409	$ 103,892	100.00%	2.32%	2,409
245	39918	CKV-Oth Tang Prop-App	$ 20,560	-	20,560.16	100.00%	2.32%	477	$ 20,560	100.00%	2.32%	477
246	39924	Oth Tang Prop - Gen.	$ -	-	-	10.95%	51.52%	-	$ -	10.95%	51.52%	-
247												
248		Total General Plant (Div 12)	$ 149,634,643	$ -	$ 149,634,643			$ 7,863,105	$ 147,932,837			$ 7,775,377
249												
250		CWIP With out AFUDC	$ 3,983,794	$ -	$ 3,983,794	10.95%	51.52%	$ 224,734	$ 3,983,794	10.95%	51.52%	$ 224,734
251												
252		Total Plant (Div 009, 091, 002, 012)	$ 1,133,896,943	$ -	$ 1,133,896,943			$ 763,121,143	$ 1,084,300,143			$ 724,669,367
253												
254		Total CWIP Without AFUDC (Div 009, 091, 002, 012)	$ 56,598,085		$ 56,598,085			$ 39,130,198	$ 56,598,085			$ 39,130,198
255												

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Jurisdictional Accumulated Depreciation & Amortization
as of December 31, 2018

Data:__X___Base Period______Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(b)3
Schedule B-3 B
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	Ending Balance	Adjustments	Adjusted Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	13 Month Average	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
		Kentucky Direct (Division 009)										
1		Intangible Plant										
2	30100	Organization	$ 8,330	$ -	$ 8,330	100%	100%	$ 8,330	$ 8,330	100%	100%	$ 8,330
3	30200	Franchises & Consents	$ 119,853	-	119,853	100%	100%	119,853	$ 119,853	100%	100%	119,853
4												
5		Total Intangible Plant Reserves	$ 128,182	$ -	$ 128,182			$ 128,182	$ 128,182			$ 128,182
6												
7		Natural Gas Production Plant										
8	32540	Rights of Ways	$ -	$ -	$ -	100%	100%	$ -	$ -	100%	100%	$ -
9	33202	Tributary Lines	$ -	-	-	100%	100%	-	$ -	100%	100%	-
10	33400	Field Meas. & Reg. Sta. Equip	$ -	-	-	100%	100%	-	$ -	100%	100%	-
11												
12		Total Natural Gas Production Plant Reserv	$ -	$ -	$ -			$ -	$ -			$ -
13												
14		Storage Plant										
15	35010	Land	$ -	$ -	$ -	100%	100%	$ -	$ -	100%	100%	$ -
16	35020	Rights of Way	$ 4,439	-	4,439	100%	100%	4,439	$ 4,434	100%	100%	4,434
17	35100	Structures and Improvements	$ 6,065	-	6,065	100%	100%	6,065	$ 5,915	100%	100%	5,915
18	35102	Compression Station Equipment	$ 112,304	-	112,304	100%	100%	112,304	$ 111,338	100%	100%	111,338
19	35103	Meas. & Reg. Sta. Structues	$ 20,326	-	20,326	100%	100%	20,326	$ 20,219	100%	100%	20,219
20	35104	Other Structures	$ 98,811	-	98,811	100%	100%	98,811	$ 97,917	100%	100%	97,917
21	35200	Wells \ Rights of Way	$ 1,069,976	-	1,069,976	100%	100%	1,069,976	$ 989,384	100%	100%	989,384
22	35201	Well Construction	$ 1,400,173	-	1,400,173	100%	100%	1,400,173	$ 1,387,338	100%	100%	1,387,338
23	35202	Well Equipment	$ 450,595	-	450,595	100%	100%	450,595	$ 450,033	100%	100%	450,033
24	35203	Cushion Gas	$ 739,273	-	739,273	100%	100%	739,273	$ 724,019	100%	100%	724,019
25	35210	Leaseholds	$ 167,629	-	167,629	100%	100%	167,629	$ 167,316	100%	100%	167,316
26	35211	Storage Rights	$ 43,595	-	43,595	100%	100%	43,595	$ 43,355	100%	100%	43,355
27	35301	Field Lines	$ (89,549)	-	(89,549)	100%	100%	(89,549)	$ (90,259)	100%	100%	(90,259)
28	35302	Tributary Lines	$ 187,800	-	187,800	100%	100%	187,800	$ 186,953	100%	100%	186,953
29	35400	Compressor Station Equipment	$ 485,848	-	485,848	100%	100%	485,848	$ 477,537	100%	100%	477,537
30	35500	Meas & Reg. Equipment	$ 199,915	-	199,915	100%	100%	199,915	$ 199,219	100%	100%	199,219
31	35600	Purification Equipment	$ 185,567	-	185,567	100%	100%	185,567	$ 181,317	100%	100%	181,317
32												
33		Total Storage Plant Reserves	$ 5,082,767	$ -	$ 5,082,767			$ 5,082,767	$ 4,956,035			$ 4,956,035

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Schedule B-3 B
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	**Ending Balance**	Adjustments	Adjusted Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	**13 Month Average**	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
34												
35		Transmission Plant										
36	36510	Land	$ -	$ -	$ -	100%	100%	$ -	$ -	100%	100%	$ -
37	36520	Rights of Way	$ 420,654	-	420,654	100%	100%	420,654	$ 414,884	100%	100%	414,884
38	36602	Structures & Improvements	$ 16,316	-	16,316	100%	100%	16,316	$ 15,879	100%	100%	15,879
39	36603	Other Structues	$ 52,418	-	52,418	100%	100%	52,418	$ 51,877	100%	100%	51,877
40	36700	Mains Cathodic Protection	$ 93,890	-	93,890	100%	100%	93,890	$ 90,399	100%	100%	90,399
41	36701	Mains - Steel	$ 17,159,073	-	17,159,073	100%	100%	17,159,073	$ 17,657,399	100%	100%	17,657,399
42	36703	Mains - Anodes	$ -	-	-	100%	100%	-	$ -	100%	100%	-
43	36900	Meas. & Reg. Equipment	$ 343,924	-	343,924	100%	100%	343,924	$ 336,097	100%	100%	336,097
44	36901	Meas. & Reg. Equipment	$ 1,744,633	-	1,744,633	100%	100%	1,744,633	$ 1,720,349	100%	100%	1,720,349
45												
46		Total Production Plant - LPG Reserves	$ 19,830,907	$ -	$ 19,830,907			$ 19,830,907	$ 20,286,883			$ 20,286,883
47												
48		Distribution Plant										
49	37400	Land & Land Rights	$ -	$ -	$ -	100%	100%	$ -	$ -	100%	100%	$ -
50	37401	Land	$ -	-	-	100%	100%	-	$ -	100%	100%	-
51	37402	Land Rights	$ 198,946	-	198,946	100%	100%	198,946	$ 177,257	100%	100%	177,257
52	37403	Land Other	$ -	-	-	100%	100%	-	$ -	100%	100%	-
53	37500	Structures & Improvements	$ 108,955	-	108,955	100%	100%	108,955	$ 105,493	100%	100%	105,493
54	37501	Structures & Improvements T.B.	$ 70,041	-	70,041	100%	100%	70,041	$ 69,013	100%	100%	69,013
55	37502	Land Rights	$ 34,747	-	34,747	100%	100%	34,747	$ 34,271	100%	100%	34,271
56	37503	Improvements	$ 1,864	-	1,864	100%	100%	1,864	$ 1,822	100%	100%	1,822
57	37600	Mains Cathodic Protection	$ 12,934,746	-	12,934,746	100%	100%	12,934,746	$ 12,718,060	100%	100%	12,718,060
58	37601	Mains - Steel	$ 31,297,268	-	31,297,268	100%	100%	31,297,268	$ 30,218,245	100%	100%	30,218,245
59	37602	Mains - Plastic	$ 16,911,814	-	16,911,814	100%	100%	16,911,814	$ 15,883,553	100%	100%	15,883,553
60	37603	Mains - Anodes	$ -	-	-	100%	100%	-	$ -	100%	100%	-
61	37604	Mains - Leak Clamps	$ -	-	-	100%	100%	-	$ -	100%	100%	-
62	37800	Meas & Reg. Sta. Equip - General	$ 2,295,802	-	2,295,802	100%	100%	2,295,802	$ 2,040,538	100%	100%	2,040,538
63	37900	Meas & Reg. Sta. Equip - City Gate	$ 910,422	-	910,422	100%	100%	910,422	$ 874,828	100%	100%	874,828
64	37905	Meas & Reg. Sta. Equipment T.b.	$ 1,002,918	-	1,002,918	100%	100%	1,002,918	$ 980,670	100%	100%	980,670
65	38000	Services	$ 32,934,303	-	32,934,303	100%	100%	32,934,303	$ 35,036,562	100%	100%	35,036,562
66	38100	Meters	$ 19,525,081	-	19,525,081	100%	100%	19,525,081	$ 18,290,752	100%	100%	18,290,752
67	38200	Meter Installaitons	$ 25,843,085	-	25,843,085	100%	100%	25,843,085	$ 25,107,867	100%	100%	25,107,867
68	38300	House Regulators	$ 3,972,540	-	3,972,540	100%	100%	3,972,540	$ 3,793,935	100%	100%	3,793,935
69	38400	House Reg. Installations	$ 88,697	-	88,697	100%	100%	88,697	$ 86,114	100%	100%	86,114
70	38500	Ind. Meas. & Reg. Sta. Equipment	$ 2,867,363	-	2,867,363	100%	100%	2,867,363	$ 2,796,967	100%	100%	2,796,967
71												
72		Total Distribution Plant Reserves	$ 150,998,591	$ -	$ 150,998,591			$ 150,998,591	$ 148,215,948			$ 148,215,948

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as of December 31, 2018

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Schedule B-3 B
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	**Ending Balance**	Adjustments	Adjusted Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	**13 Month Average**	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
73												
74		General Plant										
75	38900	38900-Land & Land Rights	$ -	$ -	$ -	100%	100%	$ -	$ -	100%	100%	$ -
76	39000	39000-Structures & Improvements	$ 1,061,493	-	1,061,493	100%	100%	1,061,493	$ 923,762	100%	100%	923,762
77	39002	39002-Structures - Brick	$ 103,168	-	103,168	100%	100%	103,168	$ 99,914	100%	100%	99,914
78	39003	39003-Improvements	$ 274,645	-	274,645	100%	100%	274,645	$ 261,312	100%	100%	261,312
79	39004	39004-Air Conditioning Equipment	$ 4,562	-	4,562	100%	100%	4,562	$ 4,319	100%	100%	4,319
80	39009	39009-Improv. to Leased Premises	$ 1,248,110	-	1,248,110	100%	100%	1,248,110	$ 1,194,303	100%	100%	1,194,303
81	39100	39100-Office Furniture & Equipment	$ 1,067,725	-	1,067,725	100%	100%	1,067,725	$ 994,844	100%	100%	994,844
82	39103	Office Machines	$ -	-	-	100%	100%	-	$ -	100%	100%	-
83	39200	39200-Transportation Equipment	$ 99,733	-	99,733	100%	100%	99,733	$ 83,004	100%	100%	83,004
84	39202	39202-WKG Trailers	$ (2,529)	-	(2,529)	100%	100%	(2,529)	$ (2,529)	100%	100%	(2,529)
85	39400	39400-Tools, Shop, & Garage Equip.	$ 1,125,068	-	1,125,068	100%	100%	1,125,068	$ 1,009,735	100%	100%	1,009,735
86	39603	39603-Ditchers	$ 39,655	-	39,655	100%	100%	39,655	$ 37,158	100%	100%	37,158
87	39604	39604-Backhoes	$ 62,818	-	62,818	100%	100%	62,818	$ 58,840	100%	100%	58,840
88	39605	39605-Welders	$ 19,141	-	19,141	100%	100%	19,141	$ 17,250	100%	100%	17,250
89	39700	39700-Communication Equipment	$ 242,784	-	242,784	100%	100%	242,784	$ 222,774	100%	100%	222,774
90	39701	Communication Equip.	$ -	-	-	100%	100%	-	$ -	100%	100%	-
91	39702	Communication Equip.	$ -	-	-	100%	100%	-	$ -	100%	100%	-
92	39705	39705-Comm. Equip. - Telemetering	$ -	-	-	100%	100%	-	$ -	100%	100%	-
93	39800	39800-Miscellaneous Equipment	$ 1,926,942	-	1,926,942	100%	100%	1,926,942	$ 1,805,131	100%	100%	1,805,131
94	39901	Servers Hardware	$ 5,282	-	5,282	100%	100%	5,282	$ 4,531	100%	100%	4,531
95	39902	Servers Software	$ -	-	-	100%	100%	-	$ -	100%	100%	-
96	39903	39903-Oth Tang Prop - Network - H/W	$ 54,550	-	54,550	100%	100%	54,550	$ 47,469	100%	100%	47,469
97	39906	39906-Oth Tang Prop - PC Hardware	$ 355,562	-	355,562	100%	100%	355,562	$ 487,081	100%	100%	487,081
98	39907	39907-Oth Tang Prop - PC Software	$ -	-	-	100%	100%	-	$ -	100%	100%	-
99	39908	39908-Oth Tang Prop - Appl Software	$ 110,712	-	110,712	100%	100%	110,712	$ 108,891	100%	100%	108,891
100		Retirement Work in Progress	$ (6,374,709)	-	(6,374,709)	100%	100%	(6,374,709)	$ (5,933,440)	100%	100%	(5,933,440)
101		Retirement Work in Progress Recon	$ -	-	-	100%	100%	-	$ -	100%	100%	-
102		AR 15 general plant amortization	$ -	-	-	100%	100%	-	$ -	100%	100%	-
103												
104		Total General Plant Reserves	$ 1,424,712	$ -	$ 1,424,712			$ 1,424,712	$ 1,424,347			$ 1,424,347
105												
106		Total Depr Reserves (Div 9)	$ 177,465,160	$ -	$ 177,465,160			$ 177,465,160	$ 175,011,396			$ 175,011,396

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Schedule B-3 B
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	**Ending Balance**	Adjustments	Adjusted Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	**13 Month Average**	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
107												
108	**Kentucky-Mid-States General Office (Division 091)**											
109												
110		Intangible Plant										
111	30100	Organization	$ -	$ -	$ -	100%	49.78%	$ -	$ -	100%	49.78%	$ -
112	30300	Misc Intangible Plant	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
113												
114		Total Intangible Plant	$ -	$ -	$ -			$ -	$ -			$ -
115												
116		Distribution Plant										
117	37400	Land & Land Rights	$ -	$ -	$ -	100%	49.78%	$ -	$ -	100%	49.78%	$ -
118	35010	Land	-	-	-	100%	49.78%	-	-	100%	49.78%	-
119	37402	Land Rights	-	-	-	100%	49.78%	-	-	100%	49.78%	-
120	37403	Land Other	-	-	-	100%	49.78%	-	-	100%	49.78%	-
121	36602	Structures & Improvements	-	-	-	100%	49.78%	-	-	100%	49.78%	-
122	37501	Structures & Improvements T.B.	-	-	-	100%	49.78%	-	-	100%	49.78%	-
123	37402	Land Rights	-	-	-	100%	49.78%	-	-	100%	49.78%	-
124	37503	Improvements	-	-	-	100%	49.78%	-	-	100%	49.78%	-
125	36700	Mains Cathodic Protection	-	-	-	100%	49.78%	-	-	100%	49.78%	-
126	36701	Mains - Steel	-	-	-	100%	49.78%	-	-	100%	49.78%	-
127	37602	Mains - Plastic	-	-	-	100%	49.78%	-	-	100%	49.78%	-
128	37800	Meas & Reg. Sta. Equip - General	-	-	-	100%	49.78%	-	-	100%	49.78%	-
129	37900	Meas & Reg. Sta. Equip - City Gate	-	-	-	100%	49.78%	-	-	100%	49.78%	-
130	37905	Meas & Reg. Sta. Equipment T.b.	-	-	-	100%	49.78%	-	-	100%	49.78%	-
131	38000	Services	-	-	-	100%	49.78%	-	-	100%	49.78%	-
132	38100	Meters	-	-	-	100%	49.78%	-	-	100%	49.78%	-
133	38200	Meter Installaitons	-	-	-	100%	49.78%	-	-	100%	49.78%	-
134	38300	House Regulators	-	-	-	100%	49.78%	-	-	100%	49.78%	-
135	38400	House Reg. Installations	-	-	-	100%	49.78%	-	-	100%	49.78%	-
136	38500	Ind. Meas. & Reg. Sta. Equipment	-	-	-	100%	49.78%	-	-	100%	49.78%	-
137	38600	Other Prop. On Cust. Prem	-	-	-	100%	49.78%	-	-	100%	49.78%	-
138												
139		Total Distribution Plant	$ -	$ -	$ -			$ -	$ -			$ -

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Line No.	Acct. No.	Account / SubAccount Titles	**Ending Balance**	Adjustments	Adjusted Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	**13 Month Average**	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
140												
141		General Plant										
142	39001	39001-Structures - Frame	$ 102,169	-	$ 102,169	100.00%	49.78%	50,860	$ 99,766	100.00%	49.78%	$ 49,663
143	39004	39004-Air Conditioning Equipment	$ 9,379	-	9,379	100%	49.78%	4,669	$ 8,815	100%	49.78%	4,388
144	39009	39009-Improv. to Leased Premises	$ 38,834	-	38,834	100%	49.78%	19,332	$ 38,834	100%	49.78%	19,332
145	39100	39100-Office Furniture & Equipment	$ 38,609	-	38,609	100%	49.78%	19,220	$ 39,253	100%	49.78%	19,540
146	39101	Office Furniture And	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
147	39103	Office Machines	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
148	39200	39200-Trans Equip- Group	$ 16,534	-	16,534	100%	49.78%	8,231	$ 15,624	100%	49.78%	7,778
149	39300	Stores Equipment	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
150	39400	39400-Tools, Shop, & Garage Equip.	$ 137,901	-	137,901	100%	49.78%	68,647	$ 134,911	100%	49.78%	67,159
151	39600	39600-Power Operated Equipment	$ 7,955	-	7,955	100%	49.78%	3,960	$ 7,508	100%	49.78%	3,737
152	39700	39700-Communication Equipment	$ (7,962)	-	(7,962)	100%	49.78%	(3,964)	$ (8,550)	100%	49.78%	(4,256)
153	39701	Communication Equip.	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
154	39702	Communication Equip.	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
155	39800	39800-Miscellaneous Equipment	$ 702,501	-	702,501	100%	49.78%	349,705	$ 688,375	100%	49.78%	342,673
156	39900	39900-Other Tangible Property	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
157	39901	39901-Oth Tang Prop - Servers - H/W	$ (34,766)	-	(34,766)	100%	49.78%	(17,306)	$ (34,766)	100%	49.78%	(17,306)
158	39902	39902-Oth Tang Prop - Servers - S/W	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
159	39903	39903-Oth Tang Prop - Network - H/W	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
160	39906	39906-Oth Tang Prop - PC Hardware	$ 70,196	-	70,196	100%	49.78%	34,944	$ 70,196	100%	49.78%	34,944
161	39907	39907-Oth Tang Prop - PC Software	$ 28,248	-	28,248	100%	49.78%	14,062	$ 23,128	100%	49.78%	11,513
162	39908	39908-Oth Tang Prop - Appl Software	$ 828,509	-	828,509	100%	49.78%	412,432	$ 828,509	100%	49.78%	412,432
163		Retirement Work in Progress	$ 52,517			100%	49.78%	-	$ 52,517	100%	49.78%	26,143
164												
165		Total General Plant	$ 1,990,625	$ -	$ 1,938,107			$ 964,790	$ 1,964,120			$ 977,739
166												
167		Total Depr Reserves (Div 91)	$ 1,990,625	$ -	$ 1,938,107			$ 964,790	$ 1,964,120			$ 977,739

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Line No.	Acct. No.	Account / SubAccount Titles	**Ending Balance**	Adjustments	Adjusted Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	**13 Month Average**	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
168												
169		**Shared Services General Office (Division 002)**										
170												
171		General Plant										
172	39000	39000-Structures & Improvements	$ 516,339	-	$ 516,339	10.40%	49.78%	26,731	$ 493,350	10.40%	49.78%	$ 25,541
173	39005	39005-G-Structures & Improvements	$ 3,747,661	-	3,747,661	100.00%	1.57%	58,862	$ 3,608,672	100.00%	1.57%	56,679
174	39009	39009-Improv. to Leased Premises	$ 9,316,766	-	9,316,766	10.40%	49.78%	482,340	$ 9,316,062	10.40%	49.78%	482,304
175	39020	Struct & Improv AEAM	$ (0)	-	(0)	100.00%	6.36%	(0)	$ (0)	100.00%	6.36%	(0)
176	39029	Improv-Leased AEAM	$ 99	-	99	100.00%	6.36%	6	$ 28	100.00%	6.36%	2
177	39100	39100-Office Furniture & Equipment	$ 1,951,797	-	1,951,797	10.40%	49.78%	101,047	$ 1,849,950	10.40%	49.78%	95,774
178	39102	39102-Remittance Processing Equipment	$ 1	-	1	10.40%	49.78%	0	$ 1	10.40%	49.78%	0
179	39103	39103-Office Furn. - Copiers & Type	$ 0	-	0	10.40%	49.78%	0	$ 0	10.40%	49.78%	0
180	39104	39104-G-Office Furniture & Equip.	$ 33,337	-	33,337	100.00%	1.57%	524	$ 31,635	100.00%	1.57%	497
181	39120	Off Furn & Equip-AEAM	$ 107,353	-	107,353	100.00%	6.36%	6,830	$ 102,125	100.00%	6.36%	6,497
182	39200	39200-Transportation Equipment	$ 5,792	-	5,792	10.40%	49.78%	300	$ 5,486	10.40%	49.78%	284
183	39300	39300-Stores Equipment	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
184	39400	39400-Tools, Shop, & Garage Equip.	$ 35,970	-	35,970	10.40%	49.78%	1,862	$ 32,756	10.40%	49.78%	1,696
185	39420	Tools And Garage-AEAM	$ 388	-	388	100.00%	6.36%	25	$ 388	100.00%	6.36%	25
186	39500	39500-Laboratory Equipment	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
187	39700	39700-Communication Equipment	$ 565,490	-	565,490	10.40%	49.78%	29,276	$ 535,334	10.40%	49.78%	27,715
188	39720	Commun Equip AEAM	$ 4,027	-	4,027	100.00%	6.36%	256	$ 3,771	100.00%	6.36%	240
189	39800	39800-Miscellaneous Equipment	$ 48,560	-	48,560	10.40%	49.78%	2,514	$ 45,314	10.40%	49.78%	2,346
190	39820	Misc Equip - AEAM	$ 1,008	-	1,008	100.00%	6.36%	64	$ 836	100.00%	6.36%	53
191	39900	39900-Other Tangible Equipm	$ 162,984	-	162,984	10.40%	49.78%	8,438	$ 162,827	10.40%	49.78%	8,430
192	39901	39901-Oth Tang Prop - Servers - H/W	$ 23,301,685	-	23,301,685	100.00%	49.78%	11,599,579	$ 21,518,817	100.00%	49.78%	10,712,067
193	39902	39902-Oth Tang Prop - Servers - S/W	$ 18,351,174	-	18,351,174	10.40%	49.78%	950,062	$ 17,438,858	10.40%	49.78%	902,831
194	39903	39903-Oth Tang Prop - Network - H/W	$ 2,715,647	-	2,715,647	10.40%	49.78%	140,592	$ 2,543,235	10.40%	49.78%	131,666
195	39904	39904-Oth Tang Prop - CPU	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
196	39905	39905-Oth Tang Prop - MF Hardware	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
197	39906	39906-Oth Tang Prop - PC Hardware	$ 1,227,065	-	1,227,065	10.40%	49.78%	63,527	$ 1,103,119	10.40%	49.78%	57,110
198	39907	39907-Oth Tang Prop - PC Software	$ 299,840	-	299,840	10.40%	49.78%	15,523	$ 249,234	10.40%	49.78%	12,903
199	39908	39908-Oth Tang Prop - Appl Software	$ 35,647,387	-	35,647,387	10.40%	49.78%	1,845,508	$ 33,415,036	10.40%	49.78%	1,729,937
200	39909	39909-Oth Tang Prop - Mainframe S/W	$ 44,629	-	44,629	10.40%	49.78%	2,311	$ 44,318	10.40%	49.78%	2,294
201	39921	Servers-Hardware-AEAM	$ 1,246,484	-	1,246,484	100.00%	6.36%	79,304	$ 1,170,658	100.00%	6.36%	74,480
202	39922	Servers-Software-AEAM	$ 515,708	-	515,708	100.00%	6.36%	32,811	$ 472,987	100.00%	6.36%	30,093
203	39923	Network Hardware-AEAM	$ 45,881	-	45,881	100.00%	6.36%	2,919	$ 43,681	100.00%	6.36%	2,779
204	39924	39924-Oth Tang Prop - Gen.	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
205	39926	Pc Hardware-AEAM	$ 71,816	-	71,816	100.00%	6.36%	4,569	$ 55,799	100.00%	6.36%	3,550
206	39928	Application SW-AEAM	$ 13,197,892	-	13,197,892	100.00%	6.36%	839,682	$ 12,528,080	100.00%	6.36%	797,067
207	39931	ALGN-Servers-Hardware	$ 67,770	-	67,770	100.00%	0.00%	-	$ 53,662	100.00%	0.00%	-
208	39932	ALGN-Servers-Software	$ 64,025	-	64,025	100.00%	0.00%	-	$ 48,541	100.00%	0.00%	-
209	39938	ALGN-Application SW	$ 4,113,000	-	4,113,000	100.00%	0.00%	-	$ 3,519,066	100.00%	0.00%	
210		Retirement Work in Progress	$ -	-	-	10.40%	49.78%	-	$ -	100.00%	49.78%	-
211												
212		Total Depr Reserves (Div 2)	$ 117,407,578	$ -	$ 117,407,578			$ 16,295,462	$ 110,393,628			$ 15,164,859
213												

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Jurisdictional Accumulated Depreciation & Amortization
as of December 31, 2018

Data:__X___Base Period______Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(b)3
Schedule B-3 B
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	Ending Balance	Adjustments	Adjusted Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	13 Month Average	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
214	**Shared Services Customer Support (Division 012)**											
215												
216		General Plant										
217	38900	38900-Land	$ -	$ -	$ -	10.95%	51.52%	$ -	$ -	10.95%	51.52%	$ -
218	38910	38910-CKV-Land & Land Rights	$ -	-	-	100.00%	2.32%	-	$ -	100.00%	2.32%	-
219	39000	39000-Structures & Improvements	$ 2,017,624	-	2,017,624	10.95%	51.52%	113,819	$ 1,823,528	10.95%	51.52%	102,869
220	39009	39009-Improv. to Leased Premises	$ 1,698,696	-	1,698,696	10.95%	51.52%	95,827	$ 1,650,738	10.95%	51.52%	93,122
221	39010	39010-CKV-Structures & Improvements	$ 2,945,092	-	2,945,092	100.00%	2.32%	68,285	$ 2,755,432	100.00%	2.32%	63,888
222	39100	39100-Office Furniture & Equipment	$ 871,244	-	871,244	10.95%	51.52%	49,149	$ 823,736	10.95%	51.52%	46,469
223	39101	Office Furniture And	$ -	-	-	10.95%	51.52%	-	$ -	10.95%	51.52%	-
224	39102	Remittance Processing	$ -	-	-	10.95%	51.52%	-	$ -	10.95%	51.52%	-
225	39103	39103-Office Furn. - Copiers & Type	$ -	-	-	10.95%	51.52%	-	$ -	10.95%	51.52%	-
226	39110	CKV-Office Furn & Eq	$ 47,615	-	47,615	100.00%	2.32%	1,104	$ 39,835	100.00%	2.32%	924
227	39210	CKV-Transportation Eq	$ 96,385	-	96,385	100.00%	2.32%	2,235	$ 93,812	100.00%	2.32%	2,175
228	39410	CKV-Tools Shop Garage	$ 122,607	-	122,607	100.00%	2.32%	2,843	$ 104,565	100.00%	2.32%	2,424
229	39510	CKV-Laboratory Equip	$ 16,579	-	16,579	100.00%	2.32%	384	$ 15,393	100.00%	2.32%	357
230	39700	39700-Communication Equipment	$ 1,089,239	-	1,089,239	10.95%	51.52%	61,446	$ 1,033,855	10.95%	51.52%	58,322
231	39710	39710-CKV-Communication Equipment	$ 159,675	-	159,675	100.00%	2.32%	3,702	$ 151,245	100.00%	2.32%	3,507
232	39800	39800-Miscellaneous Equipment	$ 13,733	-	13,733	10.95%	51.52%	775	$ 12,115	10.95%	51.52%	683
233	39810	CKV-Misc Equipment	$ 149,304	-	149,304	100.00%	2.32%	3,462	$ 137,956	100.00%	2.32%	3,199
234	39900	39900-Other Tangible Property	$ 501,737	-	501,737	10.95%	51.52%	28,304	$ 460,205	10.95%	51.52%	25,961
235	39901	39901-Oth Tang Prop - Servers - H/W	$ 5,258,881	-	5,258,881	10.95%	51.52%	296,665	$ 4,782,854	10.95%	51.52%	269,811
236	39902	39902-Oth Tang Prop - Servers - S/W	$ 1,235,832	-	1,235,832	10.95%	51.52%	69,716	$ 1,146,580	10.95%	51.52%	64,681
237	39903	39903-Oth Tang Prop - Network - H/W	$ 374,102	-	374,102	10.95%	51.52%	21,104	$ 351,089	10.95%	51.52%	19,806
238	39906	39906-Oth Tang Prop - PC Hardware	$ 580,077	-	580,077	10.95%	51.52%	32,723	$ 529,829	10.95%	51.52%	29,889
239	39907	39907-Oth Tang Prop - PC Software	$ 137,253	-	137,253	10.95%	51.52%	7,743	$ 130,947	10.95%	51.52%	7,387
240	39908	39908-Oth Tang Prop - Appl Software	$ 31,828,466	-	31,828,466	10.95%	51.52%	1,795,513	$ 28,889,060	10.95%	51.52%	1,629,695
241	39910	39910-CKV-Other Tangible Property	$ 176,542	-	176,542	100.00%	2.32%	4,093	$ 154,058	100.00%	2.32%	3,572
242	39916	39916-CKV-Oth Tang Prop-PC Hardware	$ 251,269	-	251,269	100.00%	2.32%	5,826	$ 237,228	100.00%	2.32%	5,500
243	39917	39917-CKV-Oth Tang Prop-PC Software	$ 76,530	-	76,530	100.00%	2.32%	1,774	$ 73,086	100.00%	2.32%	1,695
244	39918	CKV-Oth Tang Prop-App	$ 11,041	-	11,041	100.00%	2.32%	256	$ 10,370	100.00%	2.32%	240
245	39924	Oth Tang Prop - Gen.	$ -	-	-	10.95%	51.52%	-	$ -	10.95%	51.52%	-
246		RWIP	$ -	-	-	10.95%	51.52%	-	$ -	10.95%	51.52%	-
247												
248		Total Depr Reserves (Div 12)	$ 49,659,522	$ -	$ 49,659,522			$ 2,666,749	$ 45,407,517			$ 2,436,176
249												
250		Total Accumulated Depreciation & Amortization (Div 009, 091, 002, 012)	$ 346,522,885	$ -	$ 346,470,368			$ 197,392,161	$ 332,776,661			$ 193,590,170

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Jurisdictional Accumulated Depreciation & Amortization
as of March 31, 2020

Data:______Base Period__X___Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(b)3
Schedule B-3 F
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	Ending Balance	Adjustments	Adjusted Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	13 Month Average	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
		Kentucky Direct (Division 009)										
1		Intangible Plant										
2	30100	Organization	$ 8,330	$ -	$ 8,330	100%	100%	$ 8,330	$ 8,330	100%	100%	$ 8,330
3	30200	Franchises & Consents	$ 119,853	-	119,853	100%	100%	119,853	$ 119,853	100%	100%	119,853
4												
5		Total Intangible Plant Reserves	$ 128,182	$ -	$ 128,182			$ 128,182	$ 128,182			$ 128,182
6												
7		Natural Gas Production Plant										
8	32540	Rights of Ways	$ -	$ -	$ -	100%	100%	$ -	$ -	100%	100%	$ -
9	33202	Tributary Lines	$ -	-	-	100%	100%	-	$ -	100%	100%	-
10	33400	Field Meas. & Reg. Sta. Equip	$ -	-	-	100%	100%	-	$ -	100%	100%	-
11												
12		Total Natural Gas Production Plant Reserv	$ -	$ -	$ -			$ -	$ -			$ -
13												
14		Storage Plant										
15	35010	Land	$ -	$ -	$ -	100%	100%	$ -	$ -	100%	100%	$ -
16	35020	Rights of Way	$ 4,464	-	4,464	100%	100%	4,464	$ 4,453	100%	100%	4,453
17	35100	Structures and Improvements	$ 6,437	-	6,437	100%	100%	6,437	$ 6,289	100%	100%	6,289
18	35102	Compression Station Equipment	$ 114,702	-	114,702	100%	100%	114,702	$ 113,744	100%	100%	113,744
19	35103	Meas. & Reg. Sta. Structues	$ 20,587	-	20,587	100%	100%	20,587	$ 20,483	100%	100%	20,483
20	35104	Other Structures	$ 101,030	-	101,030	100%	100%	101,030	$ 100,144	100%	100%	100,144
21	35200	Wells \ Rights of Way	$ 1,271,387	-	1,271,387	100%	100%	1,271,387	$ 1,190,830	100%	100%	1,190,830
22	35201	Well Construction	$ 1,432,431	-	1,432,431	100%	100%	1,432,431	$ 1,419,511	100%	100%	1,419,511
23	35202	Well Equipment	$ 450,595	-	450,595	100%	100%	450,595	$ 450,595	100%	100%	450,595
24	35203	Cushion Gas	$ 770,288	-	770,288	100%	100%	770,288	$ 758,594	100%	100%	758,594
25	35210	Leaseholds	$ 168,338	-	168,338	100%	100%	168,338	$ 168,062	100%	100%	168,062
26	35211	Storage Rights	$ 44,196	-	44,196	100%	100%	44,196	$ 43,956	100%	100%	43,956
27	35301	Field Lines	$ (87,598)	-	(87,598)	100%	100%	(87,598)	$ (88,396)	100%	100%	(88,396)
28	35302	Tributary Lines	$ 190,129	-	190,129	100%	100%	190,129	$ 189,177	100%	100%	189,177
29	35400	Compressor Station Equipment	$ 505,702	-	505,702	100%	100%	505,702	$ 497,853	100%	100%	497,853
30	35500	Meas & Reg. Equipment	$ 204,824	-	204,824	100%	100%	204,824	$ 202,544	100%	100%	202,544
31	35600	Purification Equipment	$ 195,903	-	195,903	100%	100%	195,903	$ 191,797	100%	100%	191,797
32												
33		Total Storage Plant Reserves	$ 5,393,416	$ -	$ 5,393,416			$ 5,393,416	$ 5,269,635			$ 5,269,635

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Jurisdictional Accumulated Depreciation & Amortization
as of March 31, 2020

Data:______Base Period__X___Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(b)3
Schedule B-3 F
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	**Ending Balance**	Adjustments	Adjusted Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	**13 Month Average**	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
34												
35		Transmission Plant										
36	36510	Land	$ -	$ -	$ -	100%	100%	$ -	$ -	100%	100%	$ -
37	36520	Rights of Way	$ 432,651	-	432,651	100%	100%	432,651	$ 428,096	100%	100%	428,096
38	36602	Structures & Improvements	$ 17,141	-	17,141	100%	100%	17,141	$ 16,837	100%	100%	16,837
39	36603	Other Structues	$ 53,443	-	53,443	100%	100%	53,443	$ 53,066	100%	100%	53,066
40	36700	Mains Cathodic Protection	$ 100,998	-	100,998	100%	100%	100,998	$ 98,316	100%	100%	98,316
41	36701	Mains - Steel	$ 15,791,013	-	15,791,013	100%	100%	15,791,013	$ 16,387,961	100%	100%	16,387,961
42	36703	Mains - Anodes	$ -	-	-	100%	100%	-	$ -	100%	100%	-
43	36900	Meas. & Reg. Equipment	$ 359,101	-	359,101	100%	100%	359,101	$ 353,469	100%	100%	353,469
44	36901	Meas. & Reg. Equipment	$ 1,791,727	-	1,791,727	100%	100%	1,791,727	$ 1,774,251	100%	100%	1,774,251
45												
46		Total Production Plant - LPG Reserves	$ 18,546,074	$ -	$ 18,546,074			$ 18,546,074	$ 19,111,996			$ 19,111,996
47												
48		Distribution Plant										
49	37400	Land & Land Rights	$ -	$ -	$ -	100%	100%	$ -	$ -	100%	100%	$ -
50	37401	Land	$ -	-	-	100%	100%	-	$ -	100%	100%	-
51	37402	Land Rights	$ 260,969	-	260,969	100%	100%	260,969	$ 235,363	100%	100%	235,363
52	37403	Land Other	$ -	-	-	100%	100%	-	$ -	100%	100%	-
53	37500	Structures & Improvements	$ 116,704	-	116,704	100%	100%	116,704	$ 113,695	100%	100%	113,695
54	37501	Structures & Improvements T.B.	$ 72,342	-	72,342	100%	100%	72,342	$ 71,449	100%	100%	71,449
55	37502	Land Rights	$ 35,813	-	35,813	100%	100%	35,813	$ 35,399	100%	100%	35,399
56	37503	Improvements	$ 1,956	-	1,956	100%	100%	1,956	$ 1,920	100%	100%	1,920
57	37600	Mains Cathodic Protection	$ 13,343,000	-	13,343,000	100%	100%	13,343,000	$ 13,210,658	100%	100%	13,210,658
58	37601	Mains - Steel	$ 35,444,734	-	35,444,734	100%	100%	35,444,734	$ 33,671,112	100%	100%	33,671,112
59	37602	Mains - Plastic	$ 20,622,437	-	20,622,437	100%	100%	20,622,437	$ 19,028,671	100%	100%	19,028,671
60	37603	Mains - Anodes	$ -	-	-	100%	100%	-	$ -	100%	100%	-
61	37604	Mains - Leak Clamps	$ -	-	-	100%	100%	-	$ -	100%	100%	-
62	37800	Meas & Reg. Sta. Equip - General	$ 3,376,893	-	3,376,893	100%	100%	3,376,893	$ 2,894,799	100%	100%	2,894,799
63	37900	Meas & Reg. Sta. Equip - City Gate	$ 1,036,623	-	1,036,623	100%	100%	1,036,623	$ 984,409	100%	100%	984,409
64	37905	Meas & Reg. Sta. Equipment T.b.	$ 1,061,490	-	1,061,490	100%	100%	1,061,490	$ 1,038,111	100%	100%	1,038,111
65	38000	Services	$ 28,726,410	-	28,726,410	100%	100%	28,726,410	$ 30,562,139	100%	100%	30,562,139
66	38100	Meters	$ 22,606,422	-	22,606,422	100%	100%	22,606,422	$ 21,386,354	100%	100%	21,386,354
67	38200	Meter Installaitons	$ 27,709,401	-	27,709,401	100%	100%	27,709,401	$ 26,987,899	100%	100%	26,987,899
68	38300	House Regulators	$ 4,582,202	-	4,582,202	100%	100%	4,582,202	$ 4,321,265	100%	100%	4,321,265
69	38400	House Reg. Installations	$ 98,891	-	98,891	100%	100%	98,891	$ 94,403	100%	100%	94,403
70	38500	Ind. Meas. & Reg. Sta. Equipment	$ 3,014,910	-	3,014,910	100%	100%	3,014,910	$ 2,958,741	100%	100%	2,958,741
71												
72		Total Distribution Plant Reserves	$ 162,111,198	$ -	$ 162,111,198			$ 162,111,198	$ 157,596,387			$ 157,596,387

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Atmos Energy Corporation, Kentucky/Mid-States Division
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Jurisdictional Accumulated Depreciation & Amortization
as of March 31, 2020

Data:______Base Period__X___Forecasted Period
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FR 16(8)(b)3
Schedule B-3 F
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	**Ending Balance**	Adjustments	Adjusted Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	**13 Month Average**	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
73												
74		General Plant										
75	38900	38900-Land & Land Rights	$ -	$ -	$ -	100%	100%	$ -	$ -	100%	100%	$ -
76	39000	39000-Structures & Improvements	$ 1,376,546	-	1,376,546	100%	100%	1,376,546	$ 1,253,482	100%	100%	1,253,482
77	39002	39002-Structures - Brick	$ 110,370	-	110,370	100%	100%	110,370	$ 107,583	100%	100%	107,583
78	39003	39003-Improvements	$ 304,148	-	304,148	100%	100%	304,148	$ 292,730	100%	100%	292,730
79	39004	39004-Air Conditioning Equipment	$ 5,415	-	5,415	100%	100%	5,415	$ 5,049	100%	100%	5,049
80	39009	39009-Improv. to Leased Premises	$ 1,248,110	-	1,248,110	100%	100%	1,248,110	$ 1,248,110	100%	100%	1,248,110
81	39100	39100-Office Furniture & Equipment	$ 1,191,625	-	1,191,625	100%	100%	1,191,625	$ 1,144,609	100%	100%	1,144,609
82	39103	Office Machines	$ -	-	-	100%	100%	-	$ -	100%	100%	-
83	39200	39200-Transportation Equipment	$ 119,478	-	119,478	100%	100%	119,478	$ 113,788	100%	100%	113,788
84	39202	39202-WKG Trailers	$ (2,529)	-	(2,529)	100%	100%	(2,529)	$ (2,529)	100%	100%	(2,529)
85	39400	39400-Tools, Shop, & Garage Equip.	$ 1,424,932	-	1,424,932	100%	100%	1,424,932	$ 1,300,851	100%	100%	1,300,851
86	39603	39603-Ditchers	$ 39,655	-	39,655	100%	100%	39,655	$ 39,655	100%	100%	39,655
87	39604	39604-Backhoes	$ 62,818	-	62,818	100%	100%	62,818	$ 62,818	100%	100%	62,818
88	39605	39605-Welders	$ 19,456	-	19,456	100%	100%	19,456	$ 19,456	100%	100%	19,456
89	39700	39700-Communication Equipment	$ 286,494	-	286,494	100%	100%	286,494	$ 269,010	100%	100%	269,010
90	39701	Communication Equip.	$ -	-	-	100%	100%	-	$ -	100%	100%	-
91	39702	Communication Equip.	$ -	-	-	100%	100%	-	$ -	100%	100%	-
92	39705	39705-Comm. Equip. - Telemetering	$ -	-	-	100%	100%	-	$ -	100%	100%	-
93	39800	39800-Miscellaneous Equipment	$ 2,170,177	-	2,170,177	100%	100%	2,170,177	$ 2,072,883	100%	100%	2,072,883
94	39901	Servers Hardware	$ 7,698	-	7,698	100%	100%	7,698	$ 6,670	100%	100%	6,670
95	39902	Servers Software	$ -	-	-	100%	100%	-	$ -	100%	100%	-
96	39903	39903-Oth Tang Prop - Network - H/W	$ 71,374	-	71,374	100%	100%	71,374	$ 64,644	100%	100%	64,644
97	39906	39906-Oth Tang Prop - PC Hardware	$ (85,447)	-	(85,447)	100%	100%	(85,447)	$ 112,226	100%	100%	112,226
98	39907	39907-Oth Tang Prop - PC Software	$ -	-	-	100%	100%	-	$ -	100%	100%	-
99	39908	39908-Oth Tang Prop - Appl Software	$ 123,061	-	123,061	100%	100%	123,061	$ 117,916	100%	100%	117,916
100		Retirement Work in Progress	$ (6,374,709)	-	(6,374,709)	100%	100%	(6,374,709)	$ (6,374,709)	100%	100%	(6,374,709)
		Retirement Work in Progress Recon	$ -	-	-	100%	100%	-	$ -	100%	100%	-
101		AR 15 general plant amortization	$ -	-	-	100%	100%	-	$ -	100%	100%	-
102												
103		Total General Plant Reserves	$ 2,098,673	$ -	$ 2,098,673			$ 2,098,673	$ 1,854,243			$ 1,854,243
104												
105		Total Depr Reserves (Div 9)	$ 188,277,542	$ -	$ 188,277,542			$ 188,277,542	$ 183,960,444			$ 183,960,444
106												
107												

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Jurisdictional Accumulated Depreciation & Amortization
as of March 31, 2020

Data:______Base Period__X___Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

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Schedule B-3 F
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	Ending Balance	Adjustments	Adjusted Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	13 Month Average	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
108												
109		**Kentucky-Mid-States General Office (Division 091)**										
110												
111		Intangible Plant										
112	30100	Organization	$ -	$ -	$ -	100%	49.78%	$ -	$ -	100%	49.78%	$ -
113	30300	Misc Intangible Plant	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
114												
115		Total Intangible Plant	$ -	$ -	$ -			$ -	$ -			$ -
116												
117		Distribution Plant										
118	37400	Land & Land Rights	$ -	$ -	$ -	100%	49.78%	$ -	$ -	100%	49.78%	$ -
119	35010	Land	-	-	-	100%	49.78%	-	-	100%	49.78%	-
120	37402	Land Rights	-	-	-	100%	49.78%	-	-	100%	49.78%	-
121	37403	Land Other	-	-	-	100%	49.78%	-	-	100%	49.78%	-
122	36602	Structures & Improvements	-	-	-	100%	49.78%	-	-	100%	49.78%	-
123	37501	Structures & Improvements T.B.	-	-	-	100%	49.78%	-	-	100%	49.78%	-
124	37402	Land Rights	-	-	-	100%	49.78%	-	-	100%	49.78%	-
125	37503	Improvements	-	-	-	100%	49.78%	-	-	100%	49.78%	-
126	36700	Mains Cathodic Protection	-	-	-	100%	49.78%	-	-	100%	49.78%	-
127	36701	Mains - Steel	-	-	-	100%	49.78%	-	-	100%	49.78%	-
128	37602	Mains - Plastic	-	-	-	100%	49.78%	-	-	100%	49.78%	-
129	37800	Meas & Reg. Sta. Equip - General	-	-	-	100%	49.78%	-	-	100%	49.78%	-
130	37900	Meas & Reg. Sta. Equip - City Gate	-	-	-	100%	49.78%	-	-	100%	49.78%	-
131	37905	Meas & Reg. Sta. Equipment T.b.	-	-	-	100%	49.78%	-	-	100%	49.78%	-
132	38000	Services	-	-	-	100%	49.78%	-	-	100%	49.78%	-
133	38100	Meters	-	-	-	100%	49.78%	-	-	100%	49.78%	-
134	38200	Meter Installaitons	-	-	-	100%	49.78%	-	-	100%	49.78%	-
135	38300	House Regulators	-	-	-	100%	49.78%	-	-	100%	49.78%	-
136	38400	House Reg. Installations	-	-	-	100%	49.78%	-	-	100%	49.78%	-
137	38500	Ind. Meas. & Reg. Sta. Equipment	-	-	-	100%	49.78%	-	-	100%	49.78%	-
138	38600	Other Prop. On Cust. Prem	-	-	-	100%	49.78%	-	-	100%	49.78%	-
139												
140		Total Distribution Plant	$ -	$ -	$ -			$ -	$ -			$ -

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
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Schedule B-3 F
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Line No.	Acct. No.	Account / SubAccount Titles	Ending Balance	Adjustments	Adjusted Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	13 Month Average	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
141												
142		General Plant										
143	39001	39001-Structures - Frame	$ 108,392	$ -	$ 108,392	100.00%	49.78%	$ 53,957	$ 105,881	100.00%	49.78%	$ 52,708
144	39004	39004-Air Conditioning Equipment	$ 10,788	-	10,788	100%	49.78%	5,370	$ 10,224	100%	49.78%	5,090
145	39009	39009-Improv. to Leased Premises	$ 38,834	-	38,834	100%	49.78%	19,332	$ 38,834	100%	49.78%	19,332
146	39100	39100-Office Furniture & Equipment	$ 38,609	-	38,609	100%	49.78%	19,220	$ 38,609	100%	49.78%	19,220
147	39101	Office Furniture And	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
148	39103	Office Machines	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
149	39200	39200-Trans Equip- Group	$ 18,749	-	18,749	100%	49.78%	9,333	$ 17,869	100%	49.78%	8,895
150	39300	Stores Equipment	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
151	39400	39400-Tools, Shop, & Garage Equip.	$ 148,312	-	148,312	100%	49.78%	73,830	$ 143,854	100%	49.78%	71,611
152	39600	39600-Power Operated Equipment	$ 9,399	-	9,399	100%	49.78%	4,679	$ 8,789	100%	49.78%	4,375
153	39700	39700-Communication Equipment	$ (4,350)	-	(4,350)	100%	49.78%	(2,165)	$ (6,009)	100%	49.78%	(2,991)
154	39701	Communication Equip.	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
155	39702	Communication Equip.	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
156	39800	39800-Miscellaneous Equipment	$ 734,152	-	734,152	100%	49.78%	365,461	$ 721,858	100%	49.78%	359,341
157	39900	39900-Other Tangible Property	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
158	39901	39901-Oth Tang Prop - Servers - H/W	$ (34,766)	-	(34,766)	100%	49.78%	(17,306)	$ (34,766)	100%	49.78%	(17,306)
159	39902	39902-Oth Tang Prop - Servers - S/W	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
160	39903	39903-Oth Tang Prop - Network - H/W	$ -	-	-	100%	49.78%	-	$ -	100%	49.78%	-
161	39906	39906-Oth Tang Prop - PC Hardware	$ 70,196	-	70,196	100%	49.78%	34,944	$ 70,196	100%	49.78%	34,944
162	39907	39907-Oth Tang Prop - PC Software	$ 54,468	-	54,468	100%	49.78%	27,114	$ 42,359	100%	49.78%	21,086
163	39908	39908-Oth Tang Prop - Appl Software	$ 828,509	-	828,509	100%	49.78%	412,432	$ 828,509	100%	49.78%	412,432
164		Retirement Work in Progress	$ 52,517		52,517	100%	49.78%	26,143	$ 52,517	100%	49.78%	26,143
165												
166		Total General Plant	$ 2,073,811	$ -	$ 2,073,811			$ 1,032,343	$ 2,038,725			$ 1,014,877
167												
168		Total Depr Reserves (Div 91)	$ 2,073,811	$ -	$ 2,073,811			$ 1,032,343	$ 2,038,725			$ 1,014,877

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Jurisdictional Accumulated Depreciation & Amortization
as of March 31, 2020

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

FR 16(8)(b)3
Schedule B-3 F
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	Ending Balance	Adjustments	Adjusted Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	13 Month Average	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
169												
170		**Shared Services General Office (Division 002)**										
171												
172		General Plant										
173	39000	39000-Structures & Improvements	$ 582,515	$ -	$ 582,515	10.40%	49.78%	30,157	$ 555,048	10.40%	49.78%	$ 28,735
174	39005	39005-G-Structures & Improvements	$ 4,093,328	-	4,093,328	100.00%	1.57%	64,291	$ 3,955,061	100.00%	1.57%	62,119
175	39009	39009-Improv. to Leased Premises	$ 9,316,766	-	9,316,766	10.40%	49.78%	482,340	$ 9,316,766	10.40%	49.78%	482,340
176	39020	Struct & Improv AEAM	$ (0)	-	(0)	100.00%	6.36%	(0)	$ (0)	100.00%	6.36%	(0)
177	39029	Improv-Leased AEAM	$ 736	-	736	100.00%	6.36%	47	$ 433	100.00%	6.36%	28
178	39100	39100-Office Furniture & Equipment	$ 2,207,717	-	2,207,717	10.40%	49.78%	114,296	$ 2,105,155	10.40%	49.78%	108,986
179	39102	39102-Remittance Processing Equipment	$ 1	-	1	10.40%	49.78%	0	$ 1	10.40%	49.78%	0
180	39103	39103-Office Furn. - Copiers & Type	$ 0	-	0	10.40%	49.78%	0	$ 0	10.40%	49.78%	0
181	39104	39104-G-Office Furniture & Equip.	$ 40,482	-	40,482	100.00%	1.57%	636	$ 37,320	100.00%	1.57%	586
182	39120	Off Furn & Equip-AEAM	$ 120,389	-	120,389	100.00%	6.36%	7,659	$ 115,175	100.00%	6.36%	7,328
183	39200	39200-Transportation Equipment	$ 6,535	-	6,535	10.40%	49.78%	338	$ 6,238	10.40%	49.78%	323
184	39300	39300-Stores Equipment	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
185	39400	39400-Tools, Shop, & Garage Equip.	$ 43,929	-	43,929	10.40%	49.78%	2,274	$ 40,745	10.40%	49.78%	2,109
186	39420	Tools And Garage-AEAM	$ 388	-	388	100.00%	6.36%	25	$ 388	100.00%	6.36%	25
187	39500	39500-Laboratory Equipment	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
188	39700	39700-Communication Equipment	$ 641,492	-	641,492	10.40%	49.78%	33,211	$ 611,091	10.40%	49.78%	31,637
189	39720	Commun Equip AEAM	$ 4,672	-	4,672	100.00%	6.36%	297	$ 4,414	100.00%	6.36%	281
190	39800	39800-Miscellaneous Equipment	$ 57,586	-	57,586	10.40%	49.78%	2,981	$ 53,976	10.40%	49.78%	2,794
191	39820	Misc Equip - AEAM	$ 1,497	-	1,497	100.00%	6.36%	95	$ 1,301	100.00%	6.36%	83
192	39900	39900-Other Tangible Equipm	$ 162,984	-	162,984	10.40%	49.78%	8,438	$ 162,984	10.40%	49.78%	8,438
193	39901	39901-Oth Tang Prop - Servers - H/W	$ 28,340,239	-	28,340,239	10.40%	49.78%	1,467,208	$ 26,275,002	10.40%	49.78%	1,360,288
194	39902	39902-Oth Tang Prop - Servers - S/W	$ 21,199,798	-	21,199,798	10.40%	49.78%	1,097,539	$ 20,004,927	10.40%	49.78%	1,035,679
195	39903	39903-Oth Tang Prop - Network - H/W	$ 3,431,495	-	3,431,495	10.40%	49.78%	177,653	$ 3,114,229	10.40%	49.78%	161,227
196	39904	39904-Oth Tang Prop - CPU	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
197	39905	39905-Oth Tang Prop - MF Hardware	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
198	39906	39906-Oth Tang Prop - PC Hardware	$ 1,569,943	-	1,569,943	10.40%	49.78%	81,278	$ 1,431,224	10.40%	49.78%	74,096
199	39907	39907-Oth Tang Prop - PC Software	$ 436,957	-	436,957	10.40%	49.78%	22,622	$ 380,965	10.40%	49.78%	19,723
200	39908	39908-Oth Tang Prop - Appl Software	$ 41,719,463	-	41,719,463	10.40%	49.78%	2,159,867	$ 39,245,354	10.40%	49.78%	2,031,779
201	39909	39909-Oth Tang Prop - Mainframe S/W	$ 44,629	-	44,629	10.40%	49.78%	2,311	$ 44,629	10.40%	49.78%	2,311
202	39921	Servers-Hardware-AEAM	$ 1,439,509	-	1,439,509	100.00%	6.36%	91,585	$ 1,362,299	100.00%	6.36%	86,673
203	39922	Servers-Software-AEAM	$ 623,008	-	623,008	100.00%	6.36%	39,637	$ 580,088	100.00%	6.36%	36,907
204	39923	Network Hardware-AEAM	$ 51,139	-	51,139	100.00%	6.36%	3,254	$ 49,036	100.00%	6.36%	3,120
205	39924	39924-Oth Tang Prop - Gen.	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
206	39926	Pc Hardware-AEAM	$ 113,039	-	113,039	100.00%	6.36%	7,192	$ 96,550	100.00%	6.36%	6,143
207	39928	Application SW-AEAM	$ 14,889,595	-	14,889,595	100.00%	6.36%	947,312	$ 14,212,410	100.00%	6.36%	904,228
208	39931	ALGN-Servers-Hardware	$ 102,996	-	102,996	100.00%	0.00%	-	$ 88,906	100.00%	0.00%	-
209	39932	ALGN-Servers-Software	$ 102,617	-	102,617	100.00%	0.00%	-	$ 87,180	100.00%	0.00%	-
210	39938	ALGN-Application SW	$ 5,740,913	-	5,740,913	100.00%	0.00%	-	$ 5,074,484	100.00%	0.00%	-
211		Retirement Work in Progress	$ -	-	-	10.40%	49.78%	-	$ -	10.40%	49.78%	-
212												
213		Total Depr Reserves (Div 2)	$ 137,086,357	$ -	$ 137,086,357			$ 6,844,543	$ 129,013,380			$ 6,457,986

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Schedule B-3 F
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Line No.	Acct. No.	Account / SubAccount Titles	Ending Balance	Adjustments	Adjusted Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	13 Month Average	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
214												
215		**Shared Services Customer Support (Division 012)**										
216												
217		General Plant										
218	38900	38900-Land	$ -	$ -	$ -	10.95%	51.52%	$ -	$ -	10.95%	51.52%	$ -
219	38910	38910-CKV-Land & Land Rights	$ -	-	-	100.00%	2.32%	-	$ -	100.00%	2.32%	-
220	39000	39000-Structures & Improvements	$ 2,494,295	-	2,494,295	10.95%	51.52%	140,709	$ 2,303,627	10.95%	51.52%	129,953
221	39009	39009-Improv. to Leased Premises	$ 1,813,284	-	1,813,284	10.95%	51.52%	102,291	$ 1,767,449	10.95%	51.52%	99,706
222	39010	39010-CKV-Structures & Improvements	$ 3,408,099	-	3,408,099	100.00%	2.32%	79,021	$ 3,222,896	100.00%	2.32%	74,727
223	39100	39100-Office Furniture & Equipment	$ 995,778	-	995,778	10.95%	51.52%	56,174	$ 945,264	10.95%	51.52%	53,324
224	39101	Office Furniture And	$ -	-	-	10.95%	51.52%	-	$ -	10.95%	51.52%	-
225	39102	Remittance Processing	$ -	-	-	10.95%	51.52%	-	$ -	10.95%	51.52%	-
226	39103	39103-Office Furn. - Copiers & Type	$ -	-	-	10.95%	51.52%	-	$ -	10.95%	51.52%	-
227	39110	CKV-Office Furn & Eq	$ 72,530	-	72,530	100.00%	2.32%	1,682	$ 61,948	100.00%	2.32%	1,436
228	39210	CKV-Transportation Eq	$ 96,385	-	96,385	100.00%	2.32%	2,235	$ 96,385	100.00%	2.32%	2,235
229	39410	CKV-Tools Shop Garage	$ 184,199	-	184,199	100.00%	2.32%	4,271	$ 157,579	100.00%	2.32%	3,654
230	39510	CKV-Laboratory Equip	$ 19,548	-	19,548	100.00%	2.32%	453	$ 18,360	100.00%	2.32%	426
231	39700	39700-Communication Equipment	$ 1,229,135	-	1,229,135	10.95%	51.52%	69,338	$ 1,173,177	10.95%	51.52%	66,181
232	39710	39710-CKV-Communication Equipment	$ 180,991	-	180,991	100.00%	2.32%	4,196	$ 172,465	100.00%	2.32%	3,999
233	39800	39800-Miscellaneous Equipment	$ 18,363	-	18,363	10.95%	51.52%	1,036	$ 16,511	10.95%	51.52%	931
234	39810	CKV-Misc Equipment	$ 182,980	-	182,980	100.00%	2.32%	4,243	$ 169,509	100.00%	2.32%	3,930
235	39900	39900-Other Tangible Property	$ 604,449	-	604,449	10.95%	51.52%	34,098	$ 563,364	10.95%	51.52%	31,781
236	39901	39901-Oth Tang Prop - Servers - H/W	$ 6,484,556	-	6,484,556	10.95%	51.52%	365,808	$ 5,994,286	10.95%	51.52%	338,151
237	39902	39902-Oth Tang Prop - Servers - S/W	$ 1,461,754	-	1,461,754	10.95%	51.52%	82,461	$ 1,371,386	10.95%	51.52%	77,363
238	39903	39903-Oth Tang Prop - Network - H/W	$ 429,081	-	429,081	10.95%	51.52%	24,205	$ 407,089	10.95%	51.52%	22,965
239	39906	39906-Oth Tang Prop - PC Hardware	$ 716,762	-	716,762	10.95%	51.52%	40,434	$ 661,521	10.95%	51.52%	37,318
240	39907	39907-Oth Tang Prop - PC Software	$ 153,020	-	153,020	10.95%	51.52%	8,632	$ 146,713	10.95%	51.52%	8,276
241	39908	39908-Oth Tang Prop - Appl Software	$ 39,389,426	-	39,389,426	10.95%	51.52%	2,222,043	$ 36,343,197	10.95%	51.52%	2,050,199
242	39910	39910-CKV-Other Tangible Property	$ 231,991	-	231,991	100.00%	2.32%	5,379	$ 209,812	100.00%	2.32%	4,865
243	39916	39916-CKV-Oth Tang Prop-PC Hardware	$ 307,866	-	307,866	100.00%	2.32%	7,138	$ 282,904	100.00%	2.32%	6,559
244	39917	39917-CKV-Oth Tang Prop-PC Software	$ 85,140	-	85,140	100.00%	2.32%	1,974	$ 81,696	100.00%	2.32%	1,894
245	39918	CKV-Oth Tang Prop-App	$ 12,716	-	12,716	100.00%	2.32%	295	$ 12,046	100.00%	2.32%	279
246	39924	Oth Tang Prop - Gen.	$ -	-	-	10.95%	51.52%	-	$ -	10.95%	51.52%	-
247		Retirement Work in Progress	$ -	-	-	10.95%	51.52%	-	$ -	10.95%	51.52%	-
248												
249		Total Depr Reserves (Div 12)	$ 60,572,350	$ -	$ 60,572,350			$ 3,258,117	$ 56,179,183			$ 3,020,151
250												
251		Total Accumulated Depreciation & Amortization (Div 009, 091, 002, 012)	$ 388,010,060	$ -	$ 388,010,060			$ 199,412,545	$ 371,191,731			$ 194,453,459

Exhibit GKW-R-1
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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2015-00[illegible]
Depreciation Expense
Forecasted Test Period: Twelve Months Ended March 31, 20[illegible]

Data: ___ Base Period _X_ Forecasted Period
Type of Filing: ___ X ___ Original ___ Updated ___ Revised
Workpaper Reference No(s).: ___

FR 16(8)(b)[illegible]
Schedule B-3.1
Witness: Waller

Line No.	Acct No.	Account / Sub-Account Title	13 Month Ending [illegible]	Total Expense Rate %	Kentucky or Other Factors Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
		Kentucky Direct (Division 009)					
1		Intangible Plant					
2	30100	Organization	$ -	100.00%	100%	100%	$ -
3	30200	Franchises & Consents	$ -	100.00%	100%	100%	-
4							
5		Total Intangible Plant Amort.	$ -				$ -
6							
7		Natural Gas Production Plant					
8	32540	Rights of Way	$ -	100.00%	100%	100%	-
9	33202	Transmission Lines	$ -	100.00%	100%	100%	-
10	33400	Field Meas. & Reg. Sta. Equip	$ -	100.00%	100%	100%	-
11							
12		Total Natural Gas Production Plant Depr	$ -				$ -
13							
14		Storage Plant					
15	35010	Land	$ -	100.00%	100%	100%	$ -
16	35020	Rights of Way	$ 77	100.00%	100%	100%	77
17	35100	Structures and Improvements	$ 297	100.00%	100%	100%	297
18	35102	Compressor Station Equipment	$ 1,910	100.00%	100%	100%	1,910
19	35103	Meas. & Reg. Sta. Structures	$ 300	100.00%	100%	100%	300
20	35104	Other Structures	$ 1,775	100.00%	100%	100%	1,775
21	35200	Wells / Rights of Way	$ 161,122	100.00%	100%	100%	161,122
22	35201	Well Construction	$ 25,840	100.00%	100%	100%	25,840
23	35202	Well Equipment	$ -	100.00%	100%	100%	-
24	35203	Cushion Gas	$ 23,389	100.00%	100%	100%	23,389
25	35210	Leaseholds	$ 553	100.00%	100%	100%	553
26	35211	Storage Rights	$ 431	100.00%	100%	100%	431
27	35301	Field Lines	$ 1,596	100.00%	100%	100%	1,596
28	35302	Tributary Lines	$ 1,905	100.00%	100%	100%	1,905
29	35400	Compressor Station Equipment	$ 15,830	100.00%	100%	100%	15,830
30	35500	Meas. & Reg. Equipment	$ 4,561	100.00%	100%	100%	4,561
31	35600	Purification Equipment	$ 8,313	100.00%	100%	100%	8,313
32							
33		Total Storage Plant Depr	$ 247,571				$ 247,571
34							
35		Transmission Plant					
36	36510	Land	$ -	100.00%	100%	100%	$ -
37	36520	Rights of Way	$ 9,112	100.00%	100%	100%	9,112
38	36602	Structures & Improvements	$ 606	100.00%	100%	100%	606
39	36603	Other Structures	$ 754	100.00%	100%	100%	754
40	36700	Mains Cathodic Protection	$ 5,387	100.00%	100%	100%	5,387
41	36701	Mains - Steel	$ 383,107	100.00%	100%	100%	383,107
42	36703	Mains - Wrapped	$ -				
43	36900	Meas. & Reg. Equipment	$ 11,265	100.00%	100%	100%	11,265
44	36901	Meas. & Reg. Equipment	$ 34,983	100.00%	100%	100%	34,983
45							
46		Total Transmission Plant - (LFG) Depr	$ 443,210				$ 443,210

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Allowance For Working Capital
as of December 31, 2018

Data:__X___Base Period______Forecasted Period
Type of Filing:___X____Original_________Updated _________Revised
Workpaper Reference No(s).

FR 16(8)(b)4
Schedule B-4 B
Witness: Waller, Christian

Line No.	Working Capital Component	Description of methodology used to determine Jurisdictional Requirement	Workpaper Reference No.	Total Company
1	Cash Working Capital	Lead/Lag Study		$ 2,678,217
2	Material & Supplies	13 Month Average Balance	B-4.1	115,932
3	Gas Stored Underground	13 Month Average Balance	B-4.1	13,215,223
4	Prepayments	13 Month Average Balance	B-4.1	-
5	Total Working Capital Requirements			$ 16,009,373

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Allowance For Working Capital
as of March 31, 2020

Data:______Base Period__X___Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(b)4
Schedule B-4 F
Witness: Waller, Christiai

Line No.	Working Capital Component	Description of methodology used to determine Jurisdictional Requirement	Workpaper Reference No.	Total Company
1	Cash Working Capital	Lead/Lag Study		$ 2,692,759
2	Material & Supplies	13 Month Average Balance	B-4.1	117,866
3	Gas Stored Underground	13 Month Average Balance	B-4.1	8,905,991
4	Prepayments	13 Month Average Balance	B-4.1	0
5	Total Working Capital Requirements			$ 11,716,616

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Working Capital Components
as of December 31, 2018

Data:__X___Base Period______Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(b)4.1
Schedule B-4.1 B
Witness: Waller

		Base Period Ending Balance				13 Month Average			
Line No.	Description	12/31/2018 Ending Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	12/31/2018 13 Month Avg	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
1	Material & Supplies (Account 1540 & 1630)								
2	Kentucky Direct (Div 009)	$ (402,124)	100%	100%	$ (402,124)	$ (391,975)	100%	100%	$ (391,975)
3	KY/Mid-States General Office (Div 091)	1,044,575	100%	49.78%	519,990	1,020,303	100%	49.78%	507,907
4	Shared Services General Office (Div 002)	(0)	10.40%	49.78%	(0)	(0)	10.40%	49.78%	(0)
5	Shared Services Customer Support (Div 012)	-	10.95%	51.52%	-	-	10.95%	51.52%	-
6	Total	$ 642,452			$ 117,866	$ 628,329			$ 115,932
7									
8	Gas Stored Underground (Account 1641)								
9	Kentucky Direct (Div 009)	$ 13,798,753	100%	100%	$ 13,798,753	$ 13,215,223	100%	100%	##########
10	KY/Mid-States General Office (Div 091)	-	100%	49.78%	-	-	100%	49.78%	-
11	Shared Services General Office (Div 002)	-	10.40%	49.78%	-	-	10.40%	49.78%	-
12	Shared Services Customer Support (Div 012)	-	10.95%	51.52%	-	-	10.95%	51.52%	-
13	Total	$ 13,798,753			$ 13,798,753	$ 13,215,223			##########
14									
15	Prepayments (Account 1650)								
16	Kentucky Direct (Div 009)	$ -	100%	100%	$ -	$ -	100%	100%	$ -
17	KY/Mid-States General Office (Div 091)	-	100%	49.78%	-	-	100%	49.78%	-
18	Shared Services General Office (Div 002)	-	10.40%	49.78%	-	-	10.40%	49.78%	-
19	Shared Services Customer Support (Div 012)	-	10.95%	51.52%	-	-	10.95%	51.52%	-
20	Total	$ -			$ -	$ -			$ -
21									
22	Total Other Working Capital Allowances	$ 14,441,204			$ 13,916,618	$ 13,843,552			##########

Exhibit GKW-R-1
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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Working Capital Components
as of March 31, 2020

Data:______Base Period__X___Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(b)4.1
Schedule B-4.1 F
Witness: Waller

		Forecasted Period Ending Balance				13 Month Average			
Line No.	Description	3/31/2020 Ending Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	3/31/2020 13 Month Avg	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
1	Material & Supplies (Account 1540 & 1630)								
2	Kentucky Direct (Div 009)	$ (402,124)	100%	100%	$ (402,124)	$ (402,124)	100%	100%	$ (402,124)
3	KY/Mid-States General Office (Div 091)	1,044,575	100%	49.78%	519,990	1,044,575	100%	49.78%	519,990
4	Shared Services General Office (Div 002)	(0)	10.40%	49.78%	(0)	(0)	10.40%	49.78%	(0)
5	Shared Services Customer Support (Div 012)	-	10.95%	51.52%	-	-	10.95%	51.52%	-
6	Total	$ 642,452			$ 117,866	$ 642,452			$ 117,866
7									
8	Gas Stored Underground (Account 1641)								
9	Kentucky Direct (Div 009)	$ (1,769,904)	100%	100%	$ (1,769,904)	$ 8,905,991	100%	100%	$ 8,905,991
10	KY/Mid-States General Office (Div 091)	-	100%	49.78%	-	-	100%	49.78%	-
11	Shared Services General Office (Div 002)	-	10.40%	49.78%	-	-	10.40%	49.78%	-
12	Shared Services Customer Support (Div 012)	-	10.95%	51.52%	-	-	10.95%	51.52%	-
13	Total	$ (1,769,904)			$ (1,769,904)	$ 8,905,991			$ 8,905,991
14									
15	Prepayments (Account 1650)								
16	Kentucky Direct (Div 009)	$ -	100%	100%	$ -	$ -	100%	100%	$ -
17	KY/Mid-States General Office (Div 091)	-	100%	49.78%	-	-	100%	49.78%	-
18	Shared Services General Office (Div 002)	-	10.40%	49.78%	-	-	10.40%	49.78%	-
19	Shared Services Customer Support (Div 012)	-	10.95%	51.52%	-	-	10.95%	51.52%	-
20	Total	$ -			$ -	$ -			$ -
21									
22	Total Other Working Capital Allowances	$ (1,127,452)			$ (1,652,038)	$ 9,548,443			$ 9,023,857

Exhibit GKW-R-1
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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Cash Working Capital Components - 1 / 8 O&M Expenses
as of December 31, 2018

Data:__X___Base Period______Forecasted Period | FR 16(8)(b)4.2
Type of Filing:___X____Original________Updated ________Revised | Schedule B-4.2 B
Workpaper Reference No(s). | Witness: Waller, Christian

Line No.	Description	Total Company (1)	1 /8 Method Percent (2)	Jurisdictional Amount (3)
1	Cash Working Capital			
2	Production O&M Expense	$ -	12.50%	$ -
3	Storage O&M Expense	539,683	12.50%	67,460
4	Transmission O&M Expense	441,601	12.50%	55,200
5	Distribution O&M Expense	8,276,854	12.50%	1,034,607
6	Customer Accting. & Collection	2,960,697	12.50%	370,087
7	Customer Service & Information	129,523	12.50%	16,190
8	Sales Expense	440,892	12.50%	55,111
9	Admin. & General Expense	15,741,887	12.50%	1,967,736
10	Total O & M Expenses	$ 28,531,137		$ 3,566,392

Exhibit GKW-R-1
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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Cash Working Capital Components - 1 / 8 O&M Expenses
as of March 31, 2020

Data:_______Base Period__X___Forecasted Period | FR 16(8)(b)4.2
Type of Filing:___X____Original________Updated ________Revised | Schedule B-4.2 F
Workpaper Reference No(s). | Witness: Waller, Christian

Line No.	Description	Total Company (1)	1 /8 Method Percent (2)	Jurisdictional Amount (3)
1	Cash Working Capital			
2	Production O&M Expense	$ -	12.50%	$ -
3	Storage O&M Expense	488,914	12.50%	61,114
4	Transmission O&M Expense	410,103	12.50%	51,263
5	Distribution O&M Expense	7,342,106	12.50%	917,763
6	Customer Accting. & Collection	2,646,900	12.50%	330,862
7	Customer Service & Information	128,272	12.50%	16,034
8	Sales Expense	208,278	12.50%	26,035
9	Admin. & General Expense	15,996,974	12.50%	1,999,622
10	Total O & M Expenses	$ 27,221,546		$ 3,402,693

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Deferred Credits and Accumulated Deferred Income Taxes
as of December 31, 2018

Data:__X___Base Period_____Forecasted Period
Type of Filing:___X____Original________Updated
Workpaper Reference No(s).

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

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 (1)	$ 8,860,408	100%	100%	$ 8,860,408	$ 9,320,492	100%	100%	$ 9,320,492
2									
3	Account 282 - Accumulated Deferred Income Taxes	(80,791,090)	100%	100%	(80,791,090)	(73,111,195)	100%	100%	(73,111,195)
4									
5	Account 283 - Accumulated Deferred Income Taxes - Other	(47,285)	100%	100%	(47,285)	(29,054)	100%	100%	(29,054)
6									
7	Div 09 Accumulated Deferred Income Taxes	$ (71,977,967)			$ (71,977,967)	$ (63,819,757)			$ (63,819,757)
8									
9	**DIVISION 02**								
10	Account 190 - Accumulated Deferred Income Taxes	$ 437,021,385	10.40%	49.78%	$ 22,625,122	$ 453,425,662	10.40%	49.78%	$ 23,474,391
11									
12	Account 282 - Accumulated Deferred Income Taxes	(19,702,364)	10.40%	49.78%	(1,020,015)	(18,180,120)	10.40%	49.78%	(941,207)
13									
14	Account 283 - Accumulated Deferred Income Taxes - Other	24,564,904	10.40%	49.78%	1,271,755	24,541,784	10.40%	49.78%	1,270,558
15									
16	Div 02 Accumulated Deferred Income Taxes	$ 441,883,925			$ 22,876,861	$ 459,787,326			$ 23,803,742
17	**DIVISION 12**								
18	Account 190 - Accumulated Deferred Income Taxes	$ 68,526	10.95%	51.52%	$ 3,866	$ 40,821	10.95%	51.52%	$ 2,303
19									
20	Account 282 - Accumulated Deferred Income Taxes	(16,037,376)	10.95%	51.52%	(904,703)	(16,714,664)	10.95%	51.52%	(942,911)
21									
22	Account 283 - Accumulated Deferred Income Taxes - Other	0	10.95%	51.52%	0	0	10.95%	51.52%	0
23									
24	Div 012 Accumulated Deferred Income Taxes	$ (15,968,850)			$ (900,838)	$ (16,673,843)			$ (940,608)
25	**DIVISION 91**								
26									
27	Account 190 - Accumulated Deferred Income Taxes	$ 1,746,795	100%	49.78%	$ 869,555	$ 1,631,264	100%	49.78%	$ 812,043
28									
29	Account 255 - Accumulated Deferred Investment Tax Credits	0	100%	49.78%	0	0	100%	49.78%	0
30									
31	Account 282 - Accumulated Deferred Income Taxes	(745,483)	100%	49.78%	(371,101)	(1,506,488)	100%	49.78%	(749,930)
32									
33	Account 283 - Accumulated Deferred Income Taxes - Other	(886,040)	100%	49.78%	(441,071)	(879,123)	100%	49.78%	(437,627)
34									
35	Div 91 Accumulated Deferred Income Taxes	$ 115,272			$ 57,383	$ (754,347)			$ (375,514)
36									
37	**Total Deferred Inc. Taxes and Investment Tax Credits**	$ 354,052,380			$ (49,944,561)	$ 378,539,379			$ (41,332,137)

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Deferred Credits and Accumulated Deferred Income Taxes
as of March 31, 2020

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, Story

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	$ 8,610,101	100%	100%	$ 8,610,101	$ 8,667,731	100%	100%	$ 8,667,731
2									
3	Account 282 - Accumulated Deferred Income Taxes	(84,778,102)	100%	100%	(84,778,102)	(83,737,702)	100%	100%	(83,737,702)
4									
5	Account 283 - Accumulated Deferred Income Taxes - Other	(47,285)	100%	100%	(47,285)	(47,285)	100%	100%	(47,285)
6									
7	Div 09 Accumulated Deferred Income Taxes	$ (76,215,286)			$ (76,215,286)	$ (75,117,257)			$ (75,117,257)
8									
9	**DIVISION 02**								
10	Account 190 - Accumulated Deferred Income Taxes	$437,021,385	10.40%	49.78%	$ 22,625,122	$ 437,021,385	10.40%	49.78%	$ 22,625,122
11									
12	Account 282 - Accumulated Deferred Income Taxes	(20,513,590)	10.40%	49.78%	(1,062,013)	(20,293,357)	10.40%	49.78%	(1,050,611)
13									
14	Account 283 - Accumulated Deferred Income Taxes - Other	24,564,904	10.40%	49.78%	1,271,755	24,564,904	10.40%	49.78%	1,271,755
15									
16	Div 02 Accumulated Deferred Income Taxes	$441,072,699			$ 22,834,863	$ 441,292,932			$ 22,846,265
17	**DIVISION 12**								
18	Account 190 - Accumulated Deferred Income Taxes	$ 68,526	10.95%	51.52%	$ 3,866	$ 68,526	10.95%	51.52%	$ 3,866
19									
20	Account 282 - Accumulated Deferred Income Taxes	(14,837,353)	10.95%	51.52%	(837,007)	(15,109,097)	10.95%	51.52%	(852,337)
21									
22	Account 283 - Accumulated Deferred Income Taxes - Other	0	10.95%	51.52%	0	0	10.95%	51.52%	0
23									
24	Div 012 Accumulated Deferred Income Taxes	$ (14,768,827)			$ (833,142)	$ (15,040,571)			$ (848,471)
25	**DIVISION 91**								
26	Account 190 - Accumulated Deferred Income Taxes	$ 1,746,795	100%	49.78%	$ 869,555	$ 1,746,795	100%	49.78%	$ 869,555
27									
28	Account 255 - Accumulated Deferred Investment Tax Credits	0	100%	49.78%	0	0	100%	49.78%	0
29									
30	Account 282 - Accumulated Deferred Income Taxes	(723,999)	100%	49.78%	(360,407)	(724,930)	100%	49.78%	(360,870)
31									
32	Account 283 - Accumulated Deferred Income Taxes - Other	(886,040)	100%	49.78%	(441,071)	(886,040)	100%	49.78%	(441,071)
33									
34	Div 91 Accumulated Deferred Income Taxes	$ 136,756			$ 68,077	$ 135,825			$ 67,614
35									
36									
37	**Total Deferred Inc. Taxes and Investment Tax Credits**	$350,225,343			$ (54,145,487)	$ 351,270,929			$ (53,051,850)
38	*(excluding forecasted change in NOLC)*								
39	**Forecasted Change in NOLC**								1,762,858
40									
41	**Forecasted 13-month Average ADIT in Rate Base**								**(51,288,991)**
42									

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Deferred Credits and Accumulated Deferred Income Taxes
as of March 31, 2020

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, Story

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		496,005,827			
49									
50	Required Operating Income			A.1		39,333,262			
51									
52	Interest Deduction			E.1		9,382,883			
53									
54	Return on Equity Portion of Rate Base			line 50 - line 52		29,950,379			
55									
56	Return, grossed up for Income Tax	24.95%		Line 54 / (1-tax rate)		39,907,234			
57									
58	Tax Expense on Return	24.95%		Line 56 x tax rate		9,956,855			
59									
60	Change In ADIT, excluding forecasted change in NOLC			Line 37; B.5 B		(11,719,713)			
61	Required Change in NOLC					1,762,858		0	
62									
63	**Total Required Change in Accumulated Deferred Income Taxes**[1]			**B.1 F; B.1 B**		**(9,956,855)**			
64									
65									
66	**ADIT Reconciliation**								
67	**Avg ADIT, Base Period**			**B.5 B**		**(41,332,137)**			
68									
69	13-Month Average ADIT, Forecasted Period, excl, Change in NOLC			Line 37		(53,051,850)			
70	Change in NOLC			Line 39		1,762,858			
71	**Forecasted 13-month Average ADIT in Rate Base**					**(51,288,991)**			
72									
73	**Total Required Change in Accumulated Deferred Income Taxes**			Line 71 - Line 67		**(9,956,855)**			
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*								

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Customer Advances For Construction
as of December 31, 2018

Data:__X___Base Period_____Forecasted Period
Type of Filing:___X____Original________Updated
Workpaper Reference No(s).

FR 16(8)(b)6
Sch. B-6 B
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	15560 Account 252 - Customer Advances For Construction	$ (747,234)	100%	100%	$ (747,234)	$ (750,999)	100%	100%	$ (750,999)
2									
3	**DIVISION 02**								
4	15560 Account 252 - Customer Advances For Construction	-	10.40%	49.78%	-	-	10.40%	49.78%	-
5									
6	**DIVISION 12**								
7	15560 Account 252 - Customer Advances For Construction	-	10.95%	51.52%	-	-	10.95%	51.52%	-
8									
9	**DIVISION 91**								
10	15560 Account 252 - Customer Advances For Construction	-	100%	49.78%	-	-	100%	49.78%	-
11									
12	Total Account 252 - Customer Advances For Construction	$ (747,234)			$ (747,234)	$ (750,999)			$ (750,999)

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Customer Advances For Construction
as of March 31, 2020

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

FR 16(8)(b)6
Sch. B-6 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	15560	Account 252 - Customer Advances For Construction	$ (747,234)	100%	100%	$ (747,234)	$ (747,234)	100%	100%	$ (747,234)
2										
3	**DIVISION 02**									
4	15560	Account 252 - Customer Advances For Construction	-	10.40%	49.78%	-	-	10.40%	49.78%	-
5										
6	**DIVISION 12**									
7	15560	Account 252 - Customer Advances For Construction	-	10.95%	51.52%	-	-	10.95%	51.52%	-
8										
9	**DIVISION 91**									
10	15560	Account 252 - Customer Advances For Construction	0	100%	49.78%	0	0	100%	49.78%	0
11										
12		Total Account 252 - Customer Advances For Construction	$ (747,234)			$ (747,234)	$ (747,234)			$ (747,234)

Exhibit GKW-R-1
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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Base Period: Twelve Months Ended December 31, 2018
Working Capital Components

FR 16(8)(b)4.1

Line No.	Description	actual Dec-17	actual Jan-18	actual Feb-18	actual Mar-18	actual Apr-18	actual May-18	actual Jun-18	forecasted Jul-18	Budgeted Aug-18	Budgeted Sep-18	Budgeted Oct-18	Budgeted Nov-18	Budgeted Dec-18	13 Month Average
1	**Materials & Supplies**														
2															
3	Kentucky Direct (Div 009)														
4	Account 1540- Plant Materials and Operating Suppl	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Account 1630- Stores Expense Undistributed	$ (270,187)	$ (311,624)	$ (344,284)	$ (380,390)	$ (401,617)	$ (454,552)	$ (520,275)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	
6	Total Materials & Supplies	$ (270,187)	$ (311,624)	$ (344,284)	$ (380,390)	$ (401,617)	$ (454,552)	$ (520,275)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (391,975)
7															
8	KY/Mid-States General Office (Div 091)														
9	Account 1540- Plant Materials and Operating Suppl	$ 76,068	$ 76,068	$ 76,068	$ 76,068	$ 76,068	$ 64,640	$ 64,640	$ 72,258	$ 72,258	$ 72,258	$ 72,258	$ 72,258	$ 72,258	
10	Account 1630- Stores Expense Undistributed	$ 652,973	$ 730,181	$ 820,252	$ 926,972	$ 1,009,823	$ 1,111,262	$ 1,235,411	$ 972,317	$ 972,317	$ 972,317	$ 972,317	$ 972,317	$ 972,317	
11	Total Materials & Supplies	$ 729,041	$ 806,248	$ 896,320	$ 1,003,039	$ 1,085,891	$ 1,175,902	$ 1,300,051	$ 1,044,575	$ 1,044,575	$ 1,044,575	$ 1,044,575	$ 1,044,575	$ 1,044,575	$ 1,020,303
12															
13	Shared Services General Office (Div 002)														
14	Account 1540- Plant Materials and Operating Suppl	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
15	Account 1630- Stores Expense Undistributed	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	
16	Total Materials & Supplies	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)
17															
18	Shared Services Customer Support (Div 012)														
19	Account 1540- Plant Materials and Operating Suppl	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
20	Account 1630- Stores Expense Undistributed	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
21	Total Materials & Supplies	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22															
23	**Gas Stored Underground- Account 1641**														
24															
25	Kentucky Direct (Div 009)	$16,751,570	$14,268,078	$10,938,434	$ 6,984,757	$ 7,706,386	$ 9,950,295	$12,189,929	$ 9,883,670	$13,510,047	$ 17,108,213	$ 20,718,002	$17,989,771	$13,798,753	$13,215,223
26															
27	KY/Mid-States General Office (Div 091)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28															
29	Shared Services General Office (Div 002)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30															
31	Shared Services Customer Support (Div 012)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32															
33	**Prepayments- Account 1650**														
34															
35	Kentucky Direct (Div 009)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36															
37	KY/Mid-States General Office (Div 091)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38															
39	Shared Services General Office (Div 002)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40															
41	Shared Services Customer Support (Div 012)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Forecasted Test Period: Twelve Months Ended March 31, 2020
Working Capital Components

FR 16(8)(b)4.1

Line No.	Description	Budgeted Mar-19	Budgeted Apr-19	Budgeted May-19	Budgeted Jun-19	Budgeted Jul-19	Forecasted Aug-19	Forecasted Sep-19	Forecasted Oct-19	Forecasted Nov-19	Forecasted Dec-19	Forecasted Jan-20	Forecasted Feb-20	Forecasted Mar-20	13 Month Average
1	**Materials & Supplies**														
2															
3	Kentucky Direct (Div 009)														
4	Account 1540- Plant Materials and Operating Suppl	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Account 1630- Stores Expense Undistributed	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	
6	Total Materials & Supplies	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)	$ (402,124)
7															
8	KY/Mid-States General Office (Div 091)														
9	Account 1540- Plant Materials and Operating Suppl	$ 72,258	$ 72,258	$ 72,258	$ 72,258	$ 72,258	$ 72,258	$ 72,258	$ 72,258	$ 72,258	$ 72,258	$ 72,258	$ 72,258	$ 72,258	
10	Account 1630- Stores Expense Undistributed	$ 972,317	$ 972,317	$ 972,317	$ 972,317	$ 972,317	$ 972,317	$ 972,317	$ 972,317	$ 972,317	$ 972,317	$ 972,317	$ 972,317	$ 972,317	
11	Total Materials & Supplies	$ 1,044,575	$ 1,044,575	$ 1,044,575	$ 1,044,575	$ 1,044,575	$ 1,044,575	$ 1,044,575	$ 1,044,575	$ 1,044,575	$ 1,044,575	$ 1,044,575	$ 1,044,575	$ 1,044,575	$ 1,044,575
12															
13	Shared Services General Office (Div 002)														
14	Account 1540- Plant Materials and Operating Suppl	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
15	Account 1630- Stores Expense Undistributed	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	
16	Total Materials & Supplies	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)
17															
18	Shared Services Customer Support (Div 012)														
19	Account 1540- Plant Materials and Operating Suppl	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
20	Account 1630- Stores Expense Undistributed	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
21	Total Materials & Supplies	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22															
23	**Gas Stored Underground- Account 1641**														
24															
25	Kentucky Direct (Div 009)	$ (2,287,953)	$ 988,506	$ 4,223,799	$ 7,495,416	$10,805,777	$ 14,118,560	$17,407,128	$20,715,068	$18,044,748	$13,969,373	$ 8,809,436	$ 3,257,935	$ (1,769,904)	$ 8,905,991
26															
27	KY/Mid-States General Office (Div 091)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28															
29	Shared Services General Office (Div 002)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30															
31	Shared Services Customer Support (Div 012)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32															
33	**Prepayments- Account 1650**														
34															
35	Kentucky Direct (Div 009)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36															
37	KY/Mid-States General Office (Div 091)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38															
39	Shared Services General Office (Div 002)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40															
41	Shared Services Customer Support (Div 012)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Exhibit GKW-R-1
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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Deferred Credits and Accumulated Deferred Income Taxes

Base Period: Twelve Months Ended December 31, 2018

Data:__X___Base Period______Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(b)5
WP B-5 B

Line No.	Sub Acct	actual Dec-17	actual Jan-18	actual Feb-18	actual Mar-18	actual Apr-18	actual May-18	actual Jun-18	forecast Jul-18	forecast Aug-18	forecast Sep-18	forecast Oct-18	forecast Nov-18	forecast Dec-18	13 month Average
	DIVISION 09														
1	Account 190 - Accumulated Deferred Income Taxes	$ 10,404,258	$ 10,404,258	$ 10,404,258	$ 9,114,435	$ 9,114,435	$ 9,114,435	$ 9,028,253	$ 9,000,279	$ 8,972,305	$ 8,944,330	$ 8,916,356	$ 8,888,382	$ 8,860,408	$ 9,320,492
2															
3	Account 282 - Accumulated Deferred Income Taxes	(66,268,035)	(66,268,035)	(66,268,035)	(70,393,298)	(70,393,298)	(70,393,298)	(71,332,054)	(73,997,402)	(76,309,391)	(78,668,744)	(79,313,578)	(80,049,271)	(80,791,090)	(73,111,195)
4															
5	Account 283 - Accumulated Deferred Income Taxes - Other	(7,784)	(7,784)	(7,784)	(7,784)	(7,784)	(7,784)	(47,285)	(47,285)	(47,285)	(47,285)	(47,285)	(47,285)	(47,285)	(29,054)
6															
7	Div 09 Accumulated Deferred Income Taxes	$ (55,871,561)	$ (55,871,561)	$ (55,871,561)	$ (61,286,647)	$ (61,286,647)	$ (61,286,647)	$ (62,351,086)	$ (65,044,408)	$ (67,384,372)	$ (69,771,699)	$ (70,444,507)	$ (71,208,174)	$ (71,977,967)	$ (63,819,757)
8															
9	DIVISION 02														
10	Account 190 - Accumulated Deferred Income Taxes	$504,522,022	$504,522,022	$504,522,022	$440,605,947	$440,605,947	$440,605,947	$437,021,385	$ 437,021,385	$ 437,021,385	$ 437,021,385	$ 437,021,385	$ 437,021,385	$437,021,385	$ 453,425,662
11															
12	Account 282 - Accumulated Deferred Income Taxes	(17,021,092)	(17,021,092)	(17,021,092)	(17,345,030)	(17,345,030)	(17,345,030)	(17,761,671)	(18,332,471)	(18,821,962)	(19,468,077)	(19,536,914)	(19,619,728)	(19,702,364)	(18,180,120)
13															
14	Account 283 - Accumulated Deferred Income Taxes - Other	31,202,176	24,068,826	21,481,062	25,953,642	21,574,355	22,808,808	24,564,904	24,564,904	24,564,904	24,564,904	24,564,904	24,564,904	24,564,904	24,541,784
15															
16	Div 02 Accumulated Deferred Income Taxes	$ 518,703,106	$ 511,569,756	$ 508,981,992	$ 449,214,559	$ 444,835,272	$ 446,069,725	$ 443,824,618	$ 443,253,818	$ 442,764,326	$ 442,118,212	$ 442,049,374	$ 441,966,560	$ 441,883,925	$ 459,787,326
17	DIVISION 12														
18	Account 190 - Accumulated Deferred Income Taxes	$ 6,868	$ 6,868	$ 6,868	$ 10,129	$ 10,129	$ 10,129	$ 68,526	$ 68,526	$ 68,526	$ 68,526	$ 68,526	$ 68,526	$ 68,526	$ 40,821
19															
20	Account 282 - Accumulated Deferred Income Taxes	(17,234,236)	(17,234,236)	(17,234,236)	(16,885,721)	(16,885,721)	(16,885,721)	(16,728,471)	(16,674,329)	(16,579,397)	(16,436,786)	(16,303,796)	(16,170,612)	(16,037,376)	(16,714,664)
21															
22	Account 283 - Accumulated Deferred Income Taxes - Other	0	0	0	0	0	0	0	0	0	0	0	0	0	-
23															
24	Div 012 Accumulated Deferred Income Taxes	$ (17,227,368)	$ (17,227,368)	$ (17,227,368)	$ (16,875,592)	$ (16,875,592)	$ (16,875,592)	$ (16,659,945)	$ (16,605,803)	$ (16,510,871)	$ (16,368,260)	$ (16,235,270)	$ (16,102,086)	$ (15,968,850)	$ (16,673,843)
25															
26	DIVISION 91														
27	Account 190 - Accumulated Deferred Income Taxes	$ 970,543	$ 970,543	$ 970,543	$ 2,022,414	$ 2,022,414	$ 2,022,414	$ 1,746,795	$ 1,746,795	$ 1,746,795	$ 1,746,795	$ 1,746,795	$ 1,746,795	$ 1,746,795	$ 1,631,264
28															
29	Account 282 - Accumulated Deferred Income Taxes	(4,082,724)	(4,082,724)	(4,082,724)	(727,963)	(727,963)	(727,963)	(719,976)	(725,287)	(730,598)	(735,910)	(748,196)	(746,839)	(745,483)	(1,506,488)
30															
31	Account 283 - Accumulated Deferred Income Taxes - Other	(894,648)	(894,648)	(894,648)	(847,457)	(847,457)	(847,457)	(886,040)	(886,040)	(886,040)	(886,040)	(886,040)	(886,040)	(886,040)	(879,123)
32															
33	Account 255 - Accumulated Deferred Investment Tax Credits	0	0	0	0	0	0	0	0	0	0	0	0	0	-
34															
35	Div 91 Accumulated Deferred Income Taxes	$ (4,006,829)	$ (4,006,829)	$ (4,006,829)	$ 446,994	$ 446,994	$ 446,994	$ 140,779	$ 135,468	$ 130,157	$ 124,845	$ 112,559	$ 113,916	$ 115,272	$ (754,347)
36															
37	Total	$ 441,597,348	$ 434,463,997	$ 431,876,234	$ 371,499,314	$ 367,120,027	$ 368,354,480	$ 364,954,366	$ 361,739,074	$ 358,999,240	$ 356,103,098	$ 355,482,156	$ 354,770,216	$ 354,052,380	$ 378,539,379

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Deferred Credits and Accumulated Deferred Income Taxes
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:______Base Period__X___Forecasted Period
Type of Filing:___X____Original_________Updated _________Revised
Workpaper Reference No(s).

FR 16(8)(b)5
Sched. B-5

Line No.	Sub Acct	Budgeted Mar-19	Budgeted Apr-19	Budgeted May-19	Budgeted Jun-19	Budgeted Jul-19	Forecast Aug-19	Forecast Sep-19	Forecast Oct-19	Forecast Nov-19	Forecast Dec-19	Forecast Jan-20	Forecast Feb-20	Forecast Mar-20	13 month Average
	DIVISION 09														
1	Account 190 - Accumulated Deferred Income Taxes	$ 8,776,485	$ 8,749,796	$ 8,725,472	$ 8,703,434	$ 8,683,761	$ 8,666,452	$ 8,651,430	$ 8,638,772	$ 8,628,402	$ 8,620,395	$ 8,614,752	$ 8,611,245	$ 8,610,101	$ 8,667,731
2															
3	Account 282 - Accumulated Deferred Income Taxes	(82,081,168)	(82,464,469)	(82,801,658)	(83,103,565)	(83,392,421)	(83,622,353)	(83,802,023)	(84,098,342)	(84,375,882)	(84,592,543)	(84,713,183)	(84,764,417)	(84,778,102)	(83,737,702)
4															
5	Account 283 - Accumulated Deferred Income Taxes - Other	(47,285)	(47,285)	(47,285)	(47,285)	(47,285)	(47,285)	(47,285)	(47,285)	(47,285)	(47,285)	(47,285)	(47,285)	(47,285)	(47,285)
6															
7	Div 09 Accumulated Deferred Income Taxes	$ (73,351,968)	$ (73,761,957)	$ (74,123,472)	$ (74,447,416)	$ (74,755,945)	$ (75,003,186)	$ (75,197,878)	$ (75,506,855)	$ (75,794,766)	$ (76,019,433)	$ (76,145,716)	$ (76,200,458)	$ (76,215,286)	$ (75,117,257)
8															
9	DIVISION 02														
10	Account 190 - Accumulated Deferred Income Taxes	$ 437,021,385	$ 437,021,385	$ 437,021,385	$ 437,021,385	$ 437,021,385	$ 437,021,385	$ 437,021,385	$ 437,021,385	$ 437,021,385	$ 437,021,385	$ 437,021,385	$ 437,021,385	$ 437,021,385	$ 437,021,385
11															
12	Account 282 - Accumulated Deferred Income Taxes	(19,948,903)	(20,027,244)	(20,098,449)	(20,162,840)	(20,220,248)	(20,270,704)	(20,314,453)	(20,373,734)	(20,423,372)	(20,462,224)	(20,490,123)	(20,507,753)	(20,513,590)	(20,293,357)
13															
14	Account 283 - Accumulated Deferred Income Taxes - Other	24,564,904	24,564,904	24,564,904	24,564,904	24,564,904	24,564,904	24,564,904	24,564,904	24,564,904	24,564,904	24,564,904	24,564,904	24,564,904	24,564,904
15															
16	Div 02 Accumulated Deferred Income Taxes	$ 441,637,385	$ 441,559,044	$ 441,487,839	$ 441,423,448	$ 441,366,041	$ 441,315,585	$ 441,271,835	$ 441,212,555	$ 441,162,917	$ 441,124,065	$ 441,096,166	$ 441,078,535	$ 441,072,699	$ 441,292,932
17	DIVISION 12														
18	Account 190 - Accumulated Deferred Income Taxes	$ 68,526	$ 68,526	$ 68,526	$ 68,526	$ 68,526	$ 68,526	$ 68,526	$ 68,526	$ 68,526	$ 68,526	$ 68,526	$ 68,526	$ 68,526	$ 68,526
19															
20	Account 282 - Accumulated Deferred Income Taxes	(15,634,977)	(15,505,027)	(15,386,303)	(15,278,585)	(15,182,293)	(15,097,501)	(15,023,889)	(14,966,938)	(14,920,220)	(14,884,094)	(14,858,518)	(14,842,568)	(14,837,353)	(15,109,097)
21															
22	Account 283 - Accumulated Deferred Income Taxes - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23															
24	Div 012 Accumulated Deferred Income Taxes	$ (15,566,451)	$ (15,436,501)	$ (15,317,777)	$ (15,210,059)	$ (15,113,767)	$ (15,028,975)	$ (14,955,363)	$ (14,898,412)	$ (14,851,694)	$ (14,815,568)	$ (14,789,992)	$ (14,774,042)	$ (14,768,827)	$ (15,040,571)
25															
26	DIVISION 91														
27	Account 190 - Accumulated Deferred Income Taxes	$ 1,746,795	$ 1,746,795	$ 1,746,795	$ 1,746,795	$ 1,746,795	$ 1,746,795	$ 1,746,795	$ 1,746,795	$ 1,746,795	$ 1,746,795	$ 1,746,795	$ 1,746,795	$ 1,746,795	$ 1,746,795
28															
29	Account 282 - Accumulated Deferred Income Taxes	(727,874)	(726,497)	(725,241)	(724,104)	(723,089)	(722,195)	(721,420)	(727,004)	(726,534)	(726,171)	(725,916)	(724,051)	(723,999)	(724,930)
30															
31	Account 283 - Accumulated Deferred Income Taxes - Other	(886,040)	(886,040)	(886,040)	(886,040)	(886,040)	(886,040)	(886,040)	(886,040)	(886,040)	(886,040)	(886,040)	(886,040)	(886,040)	(886,040)
32															
33	Account 255 - Accumulated Deferred Investment Tax Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34															
35	Div 91 Accumulated Deferred Income Taxes	$ 132,881	$ 134,258	$ 135,514	$ 136,651	$ 137,666	$ 138,560	$ 139,335	$ 133,751	$ 134,221	$ 134,584	$ 134,839	$ 136,704	$ 136,756	$ 135,825
36															
37	Total	$ 352,851,847	$ 352,494,843	$ 352,182,104	$ 351,902,625	$ 351,633,996	$ 351,421,983	$ 351,257,929	$ 350,941,040	$ 350,650,678	$ 350,423,648	$ 350,295,298	$ 350,240,740	$ 350,225,343	$ 351,270,929

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020
Deferred Liablity Amortization

		Regulatory Liability Balance	Amortization Expense
ADIT Excess Deferred Liabilities	Mar-19	(33,781,756)	
Account 2530 - 27909	Apr-19	(33,664,788)	121,981
	May-19	(33,558,180)	121,981
	Jun-19	(33,461,598)	121,981
	Jul-19	(33,375,377)	121,981
	Aug-19	(33,299,515)	121,981
	Sep-19	(33,233,679)	121,981
	Oct-19	(33,178,203)	121,981
	Nov-19	(33,132,752)	121,981
	Dec-19	(33,097,662)	121,981
	Jan-20	(33,072,932)	121,981
	Feb-20	(33,057,559)	121,981
	Mar-20	(33,052,546)	121,981
	(13 Month Average)	**(33,305,119)**	**1,463,766**

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Deferred Credits
Base Period: Twelve Months Ended December 31, 2018

Data:__X___Base Period______Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(b)6
Sched. B-6

Line No.	Sub Acct		actual Dec-17	actual Jan-18	actual Feb-18	actual Mar-18	actual Apr-18	actual May-18	actual Jun-18	Budgeted Jul-18	Budgeted Aug-18	Budgeted Sep-18	Budgeted Oct-18	Budgeted Nov-18	Budgeted Dec-18	13 month Average
	DIVISION 09															
1		Account 252 - Customer Advances For Construction	(796,178)	(785,154)	(784,132)	(786,032)	(714,675)	(707,427)	(705,985)	(747,234)	(747,234)	(747,234)	(747,234)	(747,234)	(747,234)	(750,999)
2																
3	**DIVISION 02**															
4	15560	Account 252 - Customer Advances For Construction	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5																
6	**DIVISION 12**															
7	15560	Account 252 - Customer Advances For Construction	-	-	- -	-	-	-	-	-	-	-	-	-	-	-
8																
9	**DIVISION 91**															
10	15560	Account 252 - Customer Advances For Construction	0	0	0	0	0	0	0	-	-	-	-	-	-	-

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Deferred Credits
Base Period: Twelve Months Ended December 31, 2018

Data:______Base Period__X___Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(b)5
Sched. B-5

Line No.	Sub Acct		Budgeted Mar-19	Budgeted Apr-19	Budgeted May-19	Budgeted Jun-19	Budgeted Jul-19	Forecasted Aug-19	Forecasted Sep-19	Forecasted Oct-19	Forecasted Nov-19	Forecasted Dec-19	Forecasted Jan-20	Forecasted Feb-20	Forecasted Mar-20	13 month Average
	DIVISION 09															
1		Account 252 - Customer Advances For Construction	(747,234)	(747,234)	(747,234)	(747,234)	(747,234)	(747,234)	(747,234)	(747,234)	(747,234)	(747,234)	(747,234)	(747,234)	(747,234)	(747,234)
2																
3	**DIVISION 02**															
4	15560	Account 252 - Customer Advances For Construction	-	-	-	-	-	-	-	-	-	-	-	-	-	0
5																
6	**DIVISION 12**															
7	15560	Account 252 - Customer Advances For Construction	-	-	-	-	-	-	-	-	-	-	-	-	-	0
8																
9	**DIVISION 91**															
10	15560	Account 252 - Customer Advances For Construction	-	-	-	-	-	-	-	-	-	-	-	-	-	0

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

FR 16(8)(c) SCHEDULE C

Operating Income Summary

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Operating Income Summary
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:__X____Base Period___X___Forecasted Period — FR 16(8)(c)1
Type of Filing:___X____Original________Updated ________Revised — Schedule C-1
Workpaper Reference No(s).____________ — Witness: Waller, Densman

Line No.	Description	Base Return at Current Rates	Forecasted Return at Current Rates	Proposed Increase	Forecasted Return at Proposed Rates
1	Operating Revenue	$ 173,370,897	$ 169,717,866	$ 15,838,372	$ 185,556,238
2	Operating Expenses				
3	Purchased Gas Cost	83,882,422	78,382,354		78,382,354
4	Other O & M Expenses	28,531,137	27,221,546	79,192	27,300,738
5	Depreciation Expense	20,643,162	23,102,096		23,102,096
6	Taxes Other than Income	6,491,574	7,449,243	31,677	7,480,920
7					
8	State & Federal Income Taxes	6,320,960	6,032,846	3,924,012	9,956,858
9	Total Operating Expenses	$ 145,869,253	$ 142,188,086	$ 4,034,881	$ 146,222,966
10	Operating Income	$ 27,501,643	$ 27,529,780	$ 11,803,491	$ 39,333,272
11	Rate Base	414,053,383	496,005,827		496,005,827
12	Rate of Return	6.64%	5.55%		7.93%

Exhibit GKW-R-1
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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Adjusted Operating Income Statement
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:__X____Base Period___X___Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(c)2
Schedule C-2
Witness: Waller, Densman

Line No.	Major Group Classification	Base Year Revenue & Expenses	Utility budget Adjustments	Sched Ref.	SSU Billing Adjs	Sched Ref.	Forecasted Revenue & Expenses	Ratemaking Adjustments	Sched Ref.	Test Year Rev. & Exp. Adjusted
1	Operating Revenue	$ 173,370,897	$ (3,653,031)	D-1			$ 169,717,866	$ -		$ 169,717,866
2										
3	Operating Expenses									
4	Purchased Gas Cost	83,882,422	(5,500,067)	D-1			78,382,354	-		78,382,354
5	Production O&M Expense	-	-	D-1			-	-		-
6	Storage O&M Expense	539,683	(50,769)	D-1			488,914	-		488,914
7	Transmission O&M Expense	441,601	(31,498)	D-1			410,103	-		410,103
8	Distribution O&M Expense	8,276,854	(931,313)	D-1		*	7,345,541	(3,435)	AG DR. No 1-57	7,342,106
9	Customer Accting. & Collection	2,960,697	(313,797)	D-1		*	2,646,900	-		2,646,900
10	Customer Service & Information	129,523	(1,251)	D-1		*	128,272	-		128,272
11	Sales Expense	440,892	(36,317)	D-1		*	404,575	(196,297)	F-4	208,278
12	Admin. & General Expense	15,741,887	1,848,941	D-1		*	17,590,829	(1,593,854)	-6,F-8,F-9, F-10, F-1	15,996,974
13	Depreciation Expense	20,643,162	2,458,934	D-1			23,102,096	-		23,102,096
14	Taxes - Other	6,491,574	1,020,263	D-1			7,511,837	(62,594)	F-10	7,449,243
15	Income Taxes	6,320,960	(288,114)				6,032,846	-		6,032,846
16										
17										
18	Total Operating Expenses	$ 145,869,253	$ (1,824,987)		$ -		$ 144,044,266	$ (1,856,181)		$ 142,188,086
19										
20	Net Operating Income	$ 27,501,643	$ (1,828,044)		$ -		$ 25,673,600	$ 1,856,181		$ 27,529,780

Exhibit GKW-R-1
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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Operating Revenue and Expenses by FERC Account
Base Period: Twelve Months Ended December 31, 2018

Data:___X____Base Period________Forecasted Period — FR 16(8)(c)2.1
Type of Filing:___X____Original________Updated ________Revised — Schedule C-2.1 B
Workpaper Reference No(s).____________________ — Witness: Waller, Densman

Line No.	Account No. (s)	Account Title		Unadjusted Total Utility (1)
1		OPERATING REVENUE		
2		Sales of Gas		
3	4800	Residential	$	106,055,302
4	4805	Unbilled Residential		(6,909,256)
5	4811	Commercial		45,531,133
6	4812	Industrial		6,051,221
7	4815	Unbilled Commercial		(2,646,350)
8	4816	Unbilled Industrial		(203,688)
9	4820	Other - Public Authority		7,513,898
10	4825	Unbilled Public Authority		(571,784)
11		Total Sales of Gas	$	154,820,476
12				
13		Other Operating Income		
14	4870	Forfeited Discounts	$	1,388,389
15	4880	Misc. Service Revenues		792,006
16	4893	Revenue From Transportation of Gas of Others		17,013,346
17	4950	Other Gas Revenue		1,148,568
	4960	Provision for Rate Refunds		(1,791,888)
18		Total Other Operating Income	$	18,550,421
19				
20		TOTAL OPERATING REVENUE	$	173,370,897
21				
22		OPERATING EXPENSES		
23		Production Expense - Operation		
24	7560	Ng. Field Meas. & Reg. Station		-
25	7590	Production and gathering-Other		-
26		Total Production Expense - Operation	$	-
27				
28		Production Expense - Maintenance		
29	7610	Ng Main. Supervision & Engineering	$	-
30			$	-
31		Natural Gas Storage Expense - Operation		
32	8140	Operation Supervision & Engineering	$	-
33	8150	Maps and Records		-
34	8160	Wells Expense		326,734

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Operating Revenue and Expenses by FERC Account
Base Period: Twelve Months Ended December 31, 2018

Data:___X____Base Period________Forecasted Period — FR 16(8)(c)2.1
Type of Filing:___X____Original________Updated ________Revised — Schedule C-2.1 B
Workpaper Reference No(s).____________________ — Witness: Waller, Densman

Line No.	Account No. (s)	Account Title		Unadjusted Total Utility
				(1)
35	8170	Lines Expense		22,639
36	8180	Compressor Station Expense		28,860
37	8190	Compressor Station Expense Fuel & Power		879
38	8200	Measuring & Regulating Station Expense		6,847
39	8210	Purification		54,469
40	8240	Other		-
41	8250	Storage Well Royalties		10,451
42		Total Nat. Gas Storage Expense - Operation	$	450,879
43				
44		Natural Gas Storage Expense - Maintenance		
45	8310	Structure & Improvements	$	13,541
46	8320	Reservoirs & Wells		-
47	8340	Compressor Station Equip.		3,463
48	8350	Measuring & Regulating Station Equip.		-
49	8360	Purification Equipment		-
50	8370	Maintenance of other equipment		-
51	840/847	Other Storage Exp. - LNG		71,800
52		Total Nat. Gas Storage Expense - Maintenance	$	88,804
53				
54		Transmission Expense - Operation		
55	8500	Operation Supervision & Engineering	$	47
56	8520	Communication system expenses		-
57	8550	Other fuel & power for compression		368
58	8560	Mains Expense		395,189
59	8570	Measuring & Regulating Station Exp.		29,427
60	8590	Other Exp.		-
61	8600	Rents		-
62		Total Transmission Expense - Operation	$	425,031
63				
64		Transmission Expense - Maintenance		
65	8620	Structures and Improvements	$	-
66	8630	Mains		16,570
67	8640	Compressor Station Equipment		-
68	8650	Measuring & Reg Station Equip.		-
69	8670	Other Equipment		-

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Operating Revenue and Expenses by FERC Account
Base Period: Twelve Months Ended December 31, 2018

Data:___X____Base Period________Forecasted Period — FR 16(8)(c)2.1
Type of Filing:___X____Original________Updated ________Revised — Schedule C-2.1 B
Workpaper Reference No(s).________________ — Witness: Waller, Densman

Line No.	Account No. (s)	Account Title		Unadjusted Total Utility (1)
70		Total Transmission Expense - Maintenance	$	16,570
71				
72		Purchased Gas Cost - Operation		
73	8001	Intercompany Gas Well-head Purchases	$	-
74	8010	Natural gas field line purchases		61,223
75	8040	Natural Gas City Gate Purchases		49,880,163
76	8045	Transportation to City Gate		-
77	8050	Transmission-Operation supervision and engineering		(8,061)
78	8051	Other Gas Purchases / Gas Cost Adjustments		50,104,362
79	8052	PGA for Commercial		25,635,855
80	8053	PGA for Industrial		4,973,887
81	8054	PGA for Public Authority		4,760,332
82	8057	PGA for Transportation Sales		-
83	8058	Unbilled PGA Costs		(1,575,262)
84	8059	PGA Offset to Unrecovered Gas Cost		(73,114,227)
85	8060	Exchange Gas		(1,145,172)
86	8081	Gas Withdrawn From Storage - Debit		13,684,989
87	8082	Gas Delivered to Storage		(12,177,639)
88	8110	Gas used for products extraction-Credit		-
89	8120	Gas Used for Other Utility Operations		(16,752)
90	8130	Gas Used for Other Utility Operations		-
91	8580	Transmission and compression of gas by others		22,818,724
92		Total Purchased Gas Cost	$	83,882,422
93				
94		Distribution Expenses - Operation		
95	8700	Supervision and Engineering	$	1,452,843
96	8710	Distribution Load Dispatching		792
97	8711	Odorization		26,727
98	8720	Compressor Station Labor & Expenses		-
99	8740	Mains & Services		4,585,210
100	8750	Measuring and Regulating Station Exp. - Gen		618,282
101	8760	Measuring and Regulating Station Exp. - Ind.		125,801
102	8770	Measuring and Regulating Sta. Exp. - City Gate		45,140
103	8780	Meters and House Regulator Expense		848,813
104	8790	Customer Installations Expense		3,009

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Operating Revenue and Expenses by FERC Account
Base Period: Twelve Months Ended December 31, 2018

Data:___X____Base Period________Forecasted Period — FR 16(8)(c)2.1
Type of Filing:___X____Original________Updated ________Revised — Schedule C-2.1 B
Workpaper Reference No(s).____________________ — Witness: Waller, Densman

Line No.	Account No. (s)	Account Title		Unadjusted Total Utility (1)
105	8800	Other Expense		5,729
106	8810	Rents		443,578
107		Total Distribution Expenses - Operation	$	8,155,925
108				
109		Distribution Expenses - Maintenance		
110	8850	Supervision and Engineering	$	1,232
111	8860	Structures and Improvements		131
112	8870	Mains		30,074
113	8890	Measuring and Regulating Station Exp. - Gen		71,786
114	8900	Measuring and Regulating Station Exp. - Ind.		2,114
115	8910	Measuring and Regulating Sta. Exp. - City Gate		950
116	8920	Services		6,794
117	8930	Meters and House Regulators		-
118	8940	Other Equipment		7,847
119	8950	Maintenance of Other Plant		-
120		Total Distribution Expenses - Maintenance	$	120,929
121				
122		Customer Accounts Expenses - Operation		
123	9010	Supervision	$	-
124	9020	Meter Reading Expenses		1,127,896
125	9030	Customer Records & Collections		1,283,457
126	9040	Uncollectible Accounts		549,343
127		Total Customer Accounts Expense	$	2,960,697
128				
129		Customer Service & Information - Operation		
130	9070	Supervision	$	-
131	9080	Customer Assistance Expenses		-
132	9090	Informational and Instructional Advertising Expenses		129,523
133	9100	Misc Cust Serv & Informational Exp		-
134		Total Customer Accounts Expenses - Operation	$	129,523
135				
136		Sales Expense		
137	9110	Supervision	$	253,382
138	9120	Demonstrating and Selling Expenses		143,981
139	9130	Advertising Expenses		43,530

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Operating Revenue and Expenses by FERC Account
Base Period: Twelve Months Ended December 31, 2018

Data:___X____Base Period________Forecasted Period — FR 16(8)(c)2.1
Type of Filing:___X____Original________Updated ________Revised — Schedule C-2.1 B
Workpaper Reference No(s).____________________ — Witness: Waller, Densman

Line No.	Account No. (s)	Account Title		Unadjusted Total Utility (1)
140	9160	Miscellaneous Sales Expenses		-
141		Total Sales Expenses	$	440,892
142				
143		Administrative and General Expenses - Operation		
144	9200	Administrative and General Salaries	$	132,956
145	9210	Office Supplies and Expenses		19,311
146	9220	Administrative Expense Transferred		13,030,745
147	9230	Outside Services Employed		359,911
148	9240	Property Insurance		88,358
149	9250	Injuries and Damages		79,906
150	9260	Employee Pensions and Benefits		1,821,264
151	9270	Franchise Requirements		800
152	9280	Regulatory Commission Expense		92,766
153	930.2	Miscellaneous General Expense		83,791
154	9310	A&G-Rents	$	13,266
155		Total Administrative and General Exp. - Operation	$	15,723,075
156				
157		Administrative and General Expense - Maintenance		
158	9320	Maintenance of general plant	$	18,812
159		Total Administrative and Gen. Exp. - Maintenance	$	18,812
160				
161		Total Operation and Maintenance Expense	$	112,413,558
162				
163	403	Depreciation	$	20,643,162
164	406	Amortization	$	24,559
165	4081	Taxes Other than Income Taxes		6,491,574
166	4091-4101	Provision for Federal & State Income Taxes		6,320,960
167				
168		TOTAL OPERATING EXPENSE (incl Gas Cost)	$	145,893,812
169				
170		NET OPERATING INCOME	$	27,477,085

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Operating Revenue and Expenses by FERC Account
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:________Base Period___X____Forecasted Period — FR 16(8)(c)2.1
Type of Filing:___X____Original________Updated ________Revised — Schedule C-2.1 F
Workpaper Reference No(s). — Witness: Waller, Densman

Line No.	Account No. (s)	Account Title	Unadjusted Total Utility (1)
1		OPERATING REVENUE	
2		Sales of Gas	
3	4800	Residential	$ 96,519,490
4	4811	Commercial	41,608,020
5	4812	Industrial	5,370,385
6	4820	Other - Public Authority	6,749,807
7		Total Sales of Gas	$150,247,702
8			
9		Other Operating Income	
10	4870	Forfeited Discounts	$ 1,304,965
11	4880	Misc. Service Revenues	806,054
12	4893-4896	Revenue From Transportation of Gas of Others	14,881,382
13	4950	Other Gas Revenue	2,477,763
14		Total Other Operating Income	$ 19,470,164
15			
16		TOTAL OPERATING REVENUE	$169,717,866
17			
18		OPERATING EXPENSES	
19		Production Expense - Operation	
20	7560	Ng. Field Meas. & Reg. Station	-
21	7590	Production and gathering-Other	0
22		Total Production Expense - Operation	$ -
23			
24		Production Expense - Maintenance	
25	7610	Ng. Main. Supervision & Engineering	$ -
26			$ -
27		Natural Gas Storage Expense - Operation	
28	8140	Operation Supervision & Engineering	$ -
29	8150	Maps and Records	-
30	8160	Wells Expense	291,917
31	8170	Lines Expense	21,251
32	8180	Compressor Station Expense	25,060
33	8190	Compressor Station Expense Fuel & Power	735
34	8200	Measuring & Regulating Station Expense	6,181
35	8210	Purification	49,856
36	8240	Other	-
37	8250	Storage Well Royalties	8,763
38		Total Nat. Gas Storage Expense - Operation	$ 403,764

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Operating Revenue and Expenses by FERC Account
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:________Base Period___X____Forecasted Period — FR 16(8)(c)2.1
Type of Filing:___X____Original________Updated ________Revised — Schedule C-2.1 F
Workpaper Reference No(s).________________ — Witness: Waller, Densman

Line No.	Account No. (s)	Account Title	Unadjusted Total Utility (1)
39			
40		Natural Gas Storage Expense - Maintenance	
41	8310	Structure & Improvements	$ 12,736
42	8320	Reservoirs & Wells	-
43	8340	Compressor Station Equip.	3,331
44	8350	Measuring & Regulating Station Equip.	-
45	8360	Purification Equipment	-
46	8370	Maintenance of other equipment	-
47	841/847	Other Storage Exp. - LNG	69,083
48		Total Nat. Gas Storage Expense - Maintenance	$ 85,150
49			
50		Transmission Expense - Operation	
51	8500	Operation Supervision & Engineering	$ 35
52	8520	Communication system expenses	-
53	8550	Other Fuel & Power for Compression	308
54	8560	Mains Expense	366,202
55	8570	Measuring & Regulating Station Exp.	27,278
56	8590	Other Exp.	0
57	8600	Rents	0
58		Total Transmission Expense - Operation	$ 393,823
59			
60		Transmission Expense - Maintenance	
61	8620	Structures and Improvements	$ -
62	8630	Mains	16,280
63	8640	Compressor Station Equipment	-
64	8650	Measuring & Reg Station Equip.	-
65	8670	Other Equipment	-
66		Total Transmission Expense - Maintenance	$ 16,280
67			
68		Purchased Gas Cost - Operation	
69	8001	Intercompany Gas Well-head Purchases	$ -
70	8010	Natural gas field line purchases	61,240
71	8040	Natural Gas City Gate Purchases	51,401,318
72	8045	Transportation to City Gate	0
73	8050	Transmission-Operation supervision and engineerin	(7,602)
74	8051	Other Gas Purchases / Gas Cost Adjustments	47,517,427
75	8052	PGA for Commercial	24,564,311
76	8053	PGA for Industrial	4,854,142
77	8054	PGA for Public Authority	4,585,482
78	8057	PGA for Transportation Sales	0
79	8058	Unbilled PGA Costs	(3,124,678)
80	8059	PGA Offset to Unrecovered Gas Cost	(71,826,171)
81	8060	Exchange Gas	(2,147,338)
82	8081	Gas Withdrawn From Storage - Debit	12,436,037
83	8082	Gas Delivered to Storage	(12,626,734)
84	8110	Gas used for products extraction-Credit	0
85	8120	Gas Used for Other Utility Operations	(14,329)
86	8130	Other Gas Supply Expenses	0
87	8580	Transmission and compression of gas by others	22,709,250
88		Total Purchased Gas Cost	$ 78,382,354

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Operating Revenue and Expenses by FERC Account
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:________Base Period___X____Forecasted Period — FR 16(8)(c)2.1
Type of Filing:___X____Original________Updated ________Revised — Schedule C-2.1 F
Workpaper Reference No(s).____________________ — Witness: Waller, Densman

Line No.	Account No. (s)	Account Title	Unadjusted Total Utility (1)
89			
90		Distribution Expenses - Operation	
91	8700	Supervision and Engineering	$ 963,411
92	8710	Distribution Load Dispatching	663
93	8711	Odorization	19,956
94	8720	Compressor Station Labor & Expenses	0
95	8740	Mains & Services	4,320,719
96	8750	Measuring and Regulating Station Exp. - Gen	574,714
97	8760	Measuring and Regulating Station Exp. - Ind.	120,928
98	8770	Measuring and Regulating Sta. Exp. - City Gate	38,286
99	8780	Meters and House Regulator Expense	820,621
100	8790	Customer Installations Expense	2,246
101	8800	Other Expense	3,204
102	8810	Rents	369,768
103		Total Distribution Expenses - Operation	$ 7,234,514
104			
105		Distribution Expenses - Maintenance	
106	8850	Supervision and Engineering	$ 1,588
107	8860	Structures and Improvements	98
108	8870	Mains	28,852
109	8890	Measuring and Regulating Station Exp. - Gen	65,572
110	8900	Measuring and Regulating Station Exp. - Ind.	1,723
111	8910	Measuring and Regulating Sta. Exp. - City Gate	795
112	8920	Services	6,533
113	8930	Meters and House Regulators	0
114	8940	Other Equipment	5,866
115	8950	Maintenance of Other Plant	0
116		Total Distribution Expenses - Maintenance	$ 111,027
117			
118		Customer Accounts Expenses - Operation	
119	9010	Supervision	$ -
120	9020	Meter Reading Expenses	1,085,047
121	9030	Customer Records & Collections	1,220,802
122	9040	Uncollectible Accounts	341,050
123		Total Customer Accounts Expense	$ 2,646,900
124			
125		Customer Service & Information - Operation	
126	9070	Supervision	$ -
127	9080	Customer Assistance Expenses	0
128	9090	Informational and Instructional Advertising Expense:	128,272
129	9100	Misc Cust Serv & Informational Exp	0
130		Total Customer Accounts Expenses - Operation	$ 128,272
131			
132		Sales Expense	
133	9110	Supervision	$ 253,468
134	9120	Demonstrating and Selling Expenses	115,937
135	9130	Advertising Expenses	35,170
136	9160	Miscellaneous Sales Expenses	0
137		Total Sales Expenses	$ 404,575
138			

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Operating Revenue and Expenses by FERC Account
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:________Base Period___X____Forecasted Period — FR 16(8)(c)2.1
Type of Filing:___X____Original________Updated ________Revised — Schedule C-2.1 F
Workpaper Reference No(s).____________________ Witness: Waller, Densman

Line No.	Account No. (s)	Account Title	Unadjusted Total Utility (1)
139		Administrative and General Expenses - Operation	
140	9200	Administrative and General Salaries	$ 128,440
141	9210	Office Supplies and Expenses	17,616
142	9220	Administrative Expense Transferred	14,498,764
143	9230	Outside Services Employed	339,697
144	9240	Property Insurance	3,718
145	9250	Injuries and Damages	74,010
146	9260	Employee Pensions and Benefits	1,791,281
147	9270	Franchise Requirements	646
148	9280	Regulatory Commission Expense	671,994
149	930.2	Miscellaneous General Expense	41,757
150	9310	A&G-Rents	11,100
151		Total Administrative and General Exp. - Operation	$ 17,579,025
152			
153		Administrative and General Expense - Maintenance	
154	9320	Maintenance of General Plant	11,804
155		Total Administrative and Gen. Exp. - Maintenance	$ 11,804
156			
157		Total Operation and Maintenance Expense	$ 107,397,487
158			
159	403-406	Depreciation and Amortization	$ 23,102,096
160	4081	Taxes Other than Income Taxes	7,511,837
161	4091	Provision for Federal & State Income Taxes	6,032,846
162			
163		TOTAL OPERATING EXPENSE	$ 144,044,266
164			
165		NET OPERATING INCOME	$ 25,673,600

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Monthly Jurisdictional Operating Income by FERC Account
Base Period: Twelve Months Ended December 31, 2018

Data:___X____Base Period_________Forecasted Period
Type of Filing:___X____Original_________Updated _________Revised
Workpaper Reference No(s).

FR 16(8)(c)2.2
Schedule C-2.2
Witness: Waller, Densman

Line No.	Acct No.	Account Discription	actual Jan-18	actual Feb-18	actual Mar-18	actual Apr-18	actual May-18	actual Jun-18	Forecasted Jul-18	Forecasted Aug-18	Forecasted Sep-18	Budgeted Oct-18	Budgeted Nov-18	Budgeted Dec-18	Total
			$	$	$	$	$	$	$	$	$	$	$	$	$
1	4091-4101	Provision for income taxes	0	0	0	0		0	1,053,493	1,053,493	1,053,493	1,053,493	1,053,493	1,053,493	6,320,960
2															
3	4030	Depreciation Expense	1,669,958	1,669,433	1,675,465	1,687,862	1,698,142	1,711,940	1,725,018	1,740,222	1,736,418	1,755,383	1,776,894	1,796,428	20,643,162
4	4060	Amortization of gas plant acquisition adjustments	4,093	4,093	4,093	4,093	4,093	4,093	0	0	0	0	0	0	24,559
5	4081	Taxes other than income taxes, utility operating incor	566,216	312,504	527,772	552,951	656,880	452,394	521,535	496,100	581,759	597,919	650,316	575,228	6,491,574
6	4800	Residential sales	(18,914,908)	(17,207,260)	(12,369,456)	(11,018,918)	(6,154,176)	(3,781,327)	(3,763,546)	(3,673,077)	(3,651,533)	(4,790,276)	(8,255,729)	(12,475,096)	(106,055,302)
7	4805	Unbilled Residential Revenue	405,968	3,377,820	(677,729)	1,794,375	1,963,448	45,375							6,909,256
8	4811	Commercial Revenue	(8,086,208)	(7,415,175)	(5,130,722)	(4,548,595)	(2,633,468)	(1,707,134)	(1,766,631)	(1,668,351)	(1,650,154)	(2,091,797)	(3,547,724)	(5,285,174)	(45,531,133)
9	4812	Industrial Revenue	(973,707)	(1,334,354)	(899,111)	(594,159)	(355,283)	(174,114)	(175,217)	(200,280)	(187,714)	(254,048)	(361,508)	(541,727)	(6,051,221)
10	4815	Unbilled Comm Revenue	87,595	1,449,166	(170,766)	667,416	568,707	44,232							2,646,350
11	4816	Unbilled Industrial Revenue	(505,592)	248,260	260,988	70,107	48,981	80,944							203,688
12	4820	Other Sales to Public Authorities	(1,354,830)	(1,331,272)	(872,594)	(783,701)	(441,272)	(251,739)	(226,689)	(212,707)	(203,679)	(307,935)	(595,284)	(932,195)	(7,513,898)
13	4825	Unbilled Public Authority Revenue	20,773	303,344	(75,991)	96,466	221,124	6,068							571,784
14	4870	Forfeited discounts	(192,879)	(230,566)	(230,342)	(151,215)	(139,653)	(59,471)	(56,702)	(51,801)	(49,979)	(49,538)	(64,695)	(111,548)	(1,388,389)
15	4880	Miscellaneous service revenues	(59,320)	(48,866)	(64,491)	(54,927)	(49,757)	(54,928)	(45,327)	(57,173)	(55,395)	(88,176)	(126,545)	(87,101)	(792,006)
16	4893	Revenue-Transportation Distribution	(2,135,655)	(1,772,398)	(1,770,851)	(1,589,668)	(1,412,283)	(1,232,115)	(994,105)	(1,088,324)	(1,079,966)	(1,210,609)	(1,304,753)	(1,422,620)	(17,013,346)
17	4950	Other Gas Revenue	0	0	0	0	0	0	(157,141)	(159,212)	(171,560)	(201,623)	(213,081)	(245,950)	(1,148,568)
18	4960	Provision for Rate Refunds	651,059	688,493	452,336	0	0	0							1,791,888
19	7560	Field measuring and regulating station expenses	0	0	0	0	0	0	-	-	-	-	-	-	0
20	7590	Production and gathering-Other	0	0	0	0	0	0	-	-	-	-	-	-	0
21	8001	Intercompany Gas Well-head Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
22	8010	Natural gas field line purchases	4,142	4,391	5,053	4,211	4,530	5,323	7,324	5,555	5,780	6,581	4,319	4,014	61,223
23	8040	Natural gas city gate purchases	6,202,228	6,877,705	2,247,879	927,969	6,008,160	4,785,366	5,782,058	3,445,775	3,107,251	3,438,833	4,828,545	2,228,394	49,880,163
24	8050	Other purchases	(1,038)	(266)	(310)	(1,326)	(63)	0	(294)	(702)	(1,696)	(1,027)	(72)	(1,267)	(8,061)
25	8051	PGA for Residential	12,247,864	10,646,486	6,624,829	6,433,023	2,509,641	813,837	842,170	633,325	656,352	686,034	2,799,494	5,211,307	50,104,362
26	8052	PGA for Commercial	5,664,067	4,986,155	3,093,001	2,940,052	1,392,502	720,018	757,374	660,616	753,215	766,363	1,468,924	2,433,567	25,635,855
27	8053	PGA for Industrial	839,873	1,154,837	782,934	531,776	326,708	154,525	177,083	150,310	130,196	178,489	228,686	318,472	4,973,887
28	8054	PGA for Public Authorities	1,022,754	979,169	585,699	571,223	290,609	141,188	119,399	103,655	90,544	121,016	274,988	460,088	4,760,332
29	8058	Unbilled PGA Cost	(125,248)	(4,775,432)	1,386,749	(2,097,362)	(2,064,134)	(132,917)	(77,608)	85,243	(4,048)	1,158,383	1,984,840	3,086,270	(1,575,262)
30	8059	PGA Offset to Unrecovered Gas Cost	(12,305,787)	(14,904,062)	(9,380,793)	(8,938,833)	(5,948,837)	(3,054,463)	(2,938,143)	(2,094,409)	(2,009,258)	(2,346,774)	(3,530,039)	(5,662,828)	(73,114,227)
31	8060	Exchange gas	2,208,044	2,687,186	1,880,163	1,445,652	(953,989)	(1,317,365)	(2,793,875)	(1,537,645)	(914,548)	(1,047,042)	(1,230,719)	428,966	(1,145,172)
32	8081	Gas withdrawn from storage-Debit	2,111,350	2,831,484	3,028,402	4,186,573	93,597	0	0	207	0	0	18,607	1,414,768	13,684,989
33	8082	Gas delivered to storage-Credit	(767,260)	(82,687)	(93,915)	(68,391)	(1,292,344)	(2,081,697)	(1,808,946)	(1,190,773)	(1,392,592)	(1,315,934)	(1,769,235)	(313,867)	(12,177,639)
34	8120	Gas used for other utility operations-Credit	(3,733)	(4,846)	(8,115)	(3,819)	(1,045)	7,015	760	176	1,083	(8,888)	7,593	(2,933)	(16,752)
35	8580	Transmission and compression of gas by others	2,548,320	2,586,250	2,313,521	2,444,145	2,088,947	1,662,838	1,751,875	1,371,990	1,205,062	1,265,363	1,678,594	1,901,819	22,818,724
36	8140	Storage-Operation supervision and engineering	0	0	0	0	0	0	-	-	-	-	-	-	0
37	8160	Wells expenses	17,163	8,905	2,878	3,991	33,606	124,067	35,130	21,842	21,658	20,740	20,422	16,332	326,734
38	8170	Lines expenses	5,748	1,964	614	812	1,432	1,515	1,784	1,823	1,607	1,817	1,804	1,718	22,639
39	8180	Compressor station expenses	3,768	2,067	2,175	1,614	4,832	1,735	2,460	2,292	1,952	2,067	2,073	1,827	28,860
40	8190	Compressor station fuel and power	95	114	104	0	101	104	58	61	55	58	64	64	879
41	8200	Storage-Measuring and regulating station expenses	327	1,967	796	(62)	574	279	619	494	456	480	485	431	6,847
42	8210	Storage-Purification expenses	16,004	8,232	979	(180)	1,241	3,291	4,437	4,370	3,807	4,212	4,189	3,886	54,469
43	8240	Storage-Other expenses	0	0	0	0	0	0	-	-	-	-	-	-	0
44	8250	Storage well royalties	2,637	773	854	949	406	535	695	729	658	690	762	763	10,451
45	8310	Storage-Maintenance of structures and improvemen	460	1,020	824	88	2,405	3,015	1,509	867	885	894	879	695	13,541
46	8340	Maintenance of compressor station equipment	0	31	1,243	(178)	1,034	(319)	274	283	251	288	283	272	3,463
47	8350	Maintenance of measuring and regulating station eq	0	0	0	0	0	0	-	-	-	-	-	-	0
48	8360	Processing-Maintenance of purification equipment	0	0	0	0	0	0	-	-	-	-	-	-	0
49	8370	Maintenance of other equipment	0	0	0	0	0	0	-	-	-	-	-	-	0
50	8410	Other storage expenses-Operation labor and expens	19,063	(7,360)	6,380	5,083	5,229	9,242	5,598	5,874	5,232	5,929	5,936	5,594	71,800
51	8500	Transmission-Operation supervision and engineerin	0	0	0	0	29	0	4	4	3	3	3	2	47
52	8520	Communication system expenses	0	0	0	0	0	0	-	-	-	-	-	-	0
53	8550	Other fuel and power for Compression	40	35	38	35	35	35	24	26	23	24	27	27	368
54	8560	Mains expenses	12,456	29,431	47,534	35,351	49,826	43,468	35,638	29,707	27,268	29,313	29,064	26,134	395,189
55	8570	Transmission-Measuring and regulating station expe	2,184	10,619	(1,841)	1,398	2,143	1,419	2,247	2,319	2,056	2,310	2,327	2,245	29,427
56	8630	Transmission-Maintenance of mains	0	4,742	1,146	774	2,447	(617)	1,308	1,360	1,254	1,390	1,331	1,434	16,570
57	8640	Transmission-Maintenance of compressor sta equipr	0	0	0	0	0	0	-	-	-	-	-	-	0
58	8650	Transmission-Maintenance of measuring and regulat	0	0	0	0	0	0	-	-	-	-	-	-	0
59	8700	Distribution-Operation supervision and engineering	161,945	57,921	123,488	161,656	183,228	205,825	119,913	117,861	107,150	71,405	74,571	67,880	1,452,843

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Monthly Jurisdictional Operating Income by FERC Account
Base Period: Twelve Months Ended December 31, 2018

Data:___X____Base Period_________Forecasted Period
Type of Filing:___X____Original_________Updated _________Revised
Workpaper Reference No(s).

FR 16(8)(c)2.2
Schedule C-2.2
Witness: Waller, Densman

Line No.	Acct No.	Account Discription	actual Jan-18	actual Feb-18	actual Mar-18	actual Apr-18	actual May-18	actual Jun-18	Forecasted Jul-18	Forecasted Aug-18	Forecasted Sep-18	Budgeted Oct-18	Budgeted Nov-18	Budgeted Dec-18	Total
			$	$	$	$	$	$	$	$	$	$	$	$	$
60	8710	Distribution load dispatching	70	219	43	22	22	90	53	55	50	52	58	58	792
61	8711	Odorization	0	0	3,088	3,034	10,112	0	2,458	2,066	1,651	1,530	1,594	1,194	26,727
62	8720	Distribution-Compressor station labor and expenses	0	0	0	0	0	0	-	-	-	-	-	-	0
63	8740	Mains and Services Expenses	361,665	388,135	427,162	365,967	433,283	539,227	409,982	345,043	325,861	335,446	339,290	314,148	4,585,210
64	8750	Distribution-Measuring and regulating station expens	105,325	39,732	29,160	41,975	68,724	49,621	51,319	49,120	43,558	47,959	47,859	43,929	618,282
65	8760	Distribution-Measuring and regulating station expens	5,807	9,697	17,157	7,738	12,852	12,595	9,958	10,286	9,125	10,444	10,239	9,904	125,801
66	8770	Distribution-Measuring and regulating station expens	665	467	206	412	14,620	10,312	4,468	3,171	2,871	2,810	2,861	2,278	45,140
67	8780	Meter and house regulator expenses	123,137	64,566	51,529	67,477	71,005	67,139	66,112	68,983	61,769	70,311	70,021	66,763	848,813
68	8790	Customer installations expenses	0	0	0	1,827	0	0	277	233	186	172	179	134	3,009
69	8800	Distribution-Other expenses	733	123	1,232	445	325	699	458	479	481	204	173	380	5,729
70	8810	Distribution-Rents	38,427	45,088	46,695	54,738	40,066	36,209	29,605	31,005	28,173	29,057	31,809	32,705	443,578
71	8850	Distribution-Maintenance supervision and engineerin	38	168	0	21	183	8	101	106	165	107	57	278	1,232
72	8860	Distribution-Maintenance of structures and improvem	0	0	0	0	80	0	12	10	8	8	8	6	131
73	8870	Distribution-Maint of mains	3,558	2,538	2,437	1,169	2,175	4,207	2,595	2,338	2,131	2,393	2,350	2,183	30,074
74	8890	Maintenance of measuring and regulating station eq	9,671	8,891	3,151	8,057	1,172	8,115	5,735	5,729	5,000	5,538	5,539	5,187	71,786
75	8900	Maintenance of measuring and regulating station eq	568	(224)	464	0	420	0	186	166	138	138	141	117	2,114
76	8910	Maintenance of measuring and regulating station eq	0	0	0	0	0	560	63	66	60	63	69	69	950
77	8920	Maintenance of services	1,873	304	(34)	509	172	732	537	556	492	565	555	532	6,794
78	8930	Maintenance of meters and house regulators	0	0	0	0	0	0	-	-	-	-	-	-	0
79	8940	Distribution-Maintenance of other equipment	657	430	559	1,701	1,255	162	721	607	485	449	468	351	7,847
80	9010	Customer accounts-Operation supervision	0	0	0	0	0	0	-	-	-	-	-	-	0
81	9020	Customer accounts-Meter reading expenses	101,007	103,318	108,555	100,538	125,550	81,656	105,814	82,851	78,435	83,575	82,130	74,467	1,127,896
82	9030	Customer accounts-Customer records and collection	97,695	100,440	127,619	120,053	127,428	142,633	128,726	89,868	87,186	92,573	90,993	78,242	1,283,457
83	9040	Customer accounts-Uncollectible accounts	47,272	43,913	37,532	54,899	22,112	145,471	27,627	28,037	28,525	27,632	37,759	48,564	549,343
84	9090	Customer service-Operating informational and instru	12,027	8,459	11,706	11,387	12,611	11,148	9,548	10,607	9,633	10,813	11,124	10,450	129,523
85	9100	Customer service-Miscellaneous customer service	0	0	0	0	0	0	-	-	-	-	-	-	0
86	9110	Sales-Supervision	19,520	21,069	25,226	21,668	22,386	21,582	18,200	20,753	19,061	21,128	22,089	20,700	253,382
87	9120	Sales-Demonstrating and selling expenses	14,362	15,311	4,892	9,360	7,557	22,228	9,575	12,807	13,421	9,828	17,667	6,973	143,981
88	9130	Sales-Advertising expenses	3,358	3,435	7,297	1,606	5,854	671	2,741	4,034	4,244	2,786	5,444	2,060	43,530
89	9200	A&G-Administrative & general salaries	10,060	10,882	11,970	11,636	12,840	11,988	10,473	10,885	9,649	11,135	10,925	10,512	132,956
90	9210	A&G-Office supplies & expense	2,618	1,093	2,815	2,163	(50)	2,570	861	1,289	1,334	1,353	1,810	1,456	19,311
91	9220	A&G-Administrative expense transferred-Credit	1,077,087	921,578	1,144,944	997,870	1,306,075	776,412	1,222,953	1,071,648	1,079,925	1,130,382	1,158,533	1,143,338	13,030,745
92	9230	A&G-Outside services employed	160	0	15,004	6,065	257	185,986	40,224	22,973	23,539	23,808	23,388	18,509	359,911
93	9240	A&G-Property insurance	14,262	14,561	13,925	13,181	14,464	14,123	499	370	370	127	-	2,476	88,358
94	9250	A&G-Injuries & damages	2,590	3,244	7,379	4,034	26,251	1,996	8,299	5,129	5,652	5,380	5,618	4,333	79,906
95	9260	A&G-Employee pensions and benefits	186,991	142,600	136,940	137,078	173,569	139,491	137,766	143,670	134,798	166,081	163,969	158,311	1,821,264
96	9270	A&G-Franchise requirements	0	408	0	0	0	0	50	74	78	51	100	38	800
97	9280	A&G-Regulatory commission expenses	(5,239)	5,750	22,135	21,253	(139,296)	20,951	2,969	551	1,263	54,210	56,040	52,179	92,766
98	9302	Miscellaneous general expenses	20,220	4,982	4,024	13,199	3,649	5,222	10,787	1,805	319	11,123	7,551	913	83,791
99	9310	A&G-Rents	1,305	1,305	1,305	1,305	1,300	1,300	883	925	835	874	965	966	13,266
100	9320	A&G-Maintenance of general plant	0	0	0	0	0	11,000	2,388	401	78	2,658	1,877	410	18,812
101															
102		Operating (Income)Loss*	($6,672,482)	($6,217,458)	($4,422,972)	($3,199,299)	($902,644)	($492,418)	(582,907)	($1,022,669)	($949,599)	($1,434,919)	($2,922,109)	($4,978,569)	($27,477,085)

*Note: Debits are shown as positive, and credits are shown as negatives. Includes the Shared Services allocation.
**Note: Provision for Income Taxes is not a component of Operating Income but is included on this schedule to develop the 12 month total for use elsewhere in the model

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Monthly Jurisdictional Operating Income by FERC Account, **Div 002 Only**
Base Period: Twelve Months Ended December 31, 2018

Data:___X___Base Period________Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(c)2.2
Schedule C-2.2
Witness: Waller, Densman

Line No.	Acct No.	Account Discription	actual Jan-18	actual Mar-18	actual Mar-18	actual Apr-18	actual May-18	actual Jun-18	Forecasted Jul-18	Forecasted Aug-18	Forecasted Sep-18	Budgeted Oct-18	Budgeted Nov-18	Budgeted Dec-18	Total
			$	$	$	$	$	$	$	$	$	$	$	$	$
1	4030	Depreciation Expense	(0)	(0)	0	(0)	0	(0)	0	0	0	0	0	0	(0)
2	4081	Taxes other than income taxes, utility operating ir	0	(0)	(0)	(0)	(0)	(1,095,601)	0	0	0	0	0	0	(1,095,601)
3	8210	Storage-Purification expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
4	8700	Distribution-Operation supervision and engineerir	105,093	438	61,170	1,555	606	426	38,643	37,284	41,646	43,123	41,580	40,013	411,576
5	8560	Mains Expenses	0	0	11,697	(5,628)	913	0	1,251	1,308	1,137	1,355	1,297	1,238	14,569
6	8740	Mains and Services Expenses	6,615	3,693	4,172	(6,958)	5,773	3,329	6,080	6,080	6,084	6,227	6,227	6,227	53,552
7	8780	Meter and house regulator expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
8	8800	Distribution-Other expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
9	8850	Distribution-Maintenance supervision and engine	0	0	22,774,821	2,090,628	51,305	(237,351)	17,861,546	16,440,372	16,012,005	16,712,710	16,588,629	16,696,241	124,990,906
10	8900	Maintenance of measuring and regulating station	0	0	0	0	0	0	0	0	0	0	0	0	0
11	9010	Customer accounts-Operation supervision	0	0	0	0	0	0	0	0	0	0	0	0	0
12	9030	Customer accounts-Customer records and collec	5,314	4,452	11,757	9,549	10,028	9,468	9,034	9,444	8,222	9,786	9,361	8,948	105,363
13	9100	Customer service-Miscellaneous customer servic	0	0	0	0	0	0	0	0	0	0	0	0	0
14	9120	Sales-Demonstrating and selling expenses	8,288	0	347	0	0	19	1,659	1,659	1,962	2,005	1,757	2,643	20,339
15	9160	Sales-Miscellaneous sales expenses	0	0	0	0	1,009	591	414	385	479	470	454	439	4,241
16	9200	A&G-Administrative & general salaries	205,452	(627,908)	(2,192,440)	(401,667)	(899,220)	(5,306,855)	(19,561,056)	(17,493,191)	(17,457,761)	(17,685,819)	(17,715,212)	(18,042,505)	(117,178,183)
17	9210	A&G-Office supplies & expense	2,142,790	1,771,426	1,682,549	2,041,980	1,933,265	2,210,856	2,521,099	2,498,875	2,668,458	2,925,307	2,709,077	2,859,363	27,965,045
18	9220	A&G-Administrative expense transferred-Credit	(8,771,030)	(7,951,782)	(10,587,390)	(8,252,356)	(13,352,610)	(5,009,612)	(9,656,780)	(8,022,889)	(7,941,749)	(8,813,419)	(8,811,471)	(8,957,492)	(106,128,578)
19	9230	A&G-Outside services employed	689,944	802,488	1,004,663	1,133,846	1,038,732	1,348,513	843,365	804,371	921,592	903,707	881,820	924,838	11,297,879
20	9240	A&G-Property insurance	11,426	11,426	10,819	10,819	10,819	10,819	12,394	12,394	12,394	11,863	11,969	11,969	139,111
21	9250	A&G-Injuries & damages	1,587,463	1,587,213	1,877,081	1,587,313	1,587,109	1,084,489	1,745,129	1,745,643	1,744,101	1,671,403	1,685,753	1,685,234	19,587,929
22	9260	A&G-Employee pensions and benefits	2,898,622	3,461,898	5,497,584	3,538,375	9,024,587	4,392,184	5,377,761	3,157,123	2,979,918	3,372,567	3,772,917	3,709,119	51,182,656
23	9301	A&G-General advertising expense	0	0	0	0	0	0	0	0	0	0	0	0	0
24	9302	Miscellaneous general expenses	579,195	377,496	2,956,336	386,906	186,525	263,397	271,775	276,565	463,356	261,299	243,628	509,151	6,775,628
25	9310	A&G-Rents	506,336	515,892	421,345	109,297	405,038	456,120	491,303	488,913	501,305	534,953	532,113	502,561	5,465,175
26	9320	A&G-Maintenance of general plant	24,040	45,828	4,367	30,115	47,043	34,154	36,382	35,664	36,849	42,464	40,101	42,014	419,021
27		Operating (Income)Loss*	($451)	$2,559	$23,538,878	$2,273,773	$50,921	($1,835,054)	$0	($0)	($0)	$0	($0)	($0)	$24,030,627
28															
29	9220	A&G-Administrative expense transferred-Credit	(8,771,030)	(7,951,782)	(10,587,390)	(8,252,356)	(13,352,610)	(5,009,612)	(9,656,780)	(8,022,889)	(7,941,749)	(8,813,419)	(8,811,471)	(8,957,492)	(106,128,578)
30		Allocation Factor to Kentucky	5.86%	5.80%	5.70%	5.95%	5.60%	6.28%	5.18%	5.18%	5.18%	5.18%	5.18%	5.18%	5.50%
31		Total Allocated Amount	(513,970)	(461,380)	(603,222)	(490,841)	(747,763)	(314,607)	(499,943)	(415,355)	(411,154)	(456,281)	(456,180)	(463,740)	(5,834,437)

*Note: Debits are shown as positive, and credits are shown as negatives. Includes the Shared Services allocation.

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Monthly Jurisdictional Operating Income by FERC Account, **Div 012 Only**
Base Period: Twelve Months Ended December 31, 2018

Data:___X____Base Period________Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(c)2.2
Schedule C-2.2
Witness: Waller, Densman

Line No.	Acct No.	Account Discription	actual Jan-18	actual Mar-18	actual Mar-18	actual Apr-18	actual May-18	actual Jun-18	Forecasted Jul-18	Forecasted Aug-18	Forecasted Sep-18	Budgeted Oct-18	Budgeted Nov-18	Budgeted Dec-18	Total
			$	$	$	$	$	$	$	$	$	$	$	$	$
1	4030	Depreciation Expense	0	0	0	(0)	0	(0)	0	0	0	0	0	0	(0)
2	4081	Taxes other than income taxes, utility operating income	0	(0)	(0)	0	0	(0)	0	0	0	0	0	0	0
3	8700	Distribution-Operation supervision and engineering	0	395	0	0	1,137	3,316	1,031	1,092	1,089	851	851	985	10,746
4	8740	Mains and Services Expenses	1,599	1,401	1,614	1,672	1,409	1,471	1,687	1,687	1,687	1,724	1,724	1,724	19,399
5	8800	Distribution-Other expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
6	9010	Customer accounts-Operation supervision	352,196	307,312	349,670	327,960	361,872	319,906	428,394	444,161	408,993	434,598	432,744	412,755	4,580,562
7	9020	Customer accounts-Meter reading expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
8	9030	Customer accounts-Customer records and collections expenses	1,741,680	1,492,516	1,708,357	1,522,186	1,617,146	1,504,397	1,914,208	1,944,277	1,703,896	1,986,287	1,880,332	1,794,672	20,809,954
9	9200	A&G-Administrative & general salaries	372,338	306,658	349,706	390,956	367,638	344,049	413,871	432,534	377,114	436,138	417,906	398,791	4,607,698
10	9210	A&G-Office supplies & expense	589,412	605,657	714,835	706,341	644,057	628,961	191,855	180,790	179,692	153,090	150,562	151,916	4,897,168
11	9220	A&G-Administrative expense transferred-Credit	(4,107,536)	(3,616,023)	(3,896,279)	(3,884,435)	(4,070,220)	(3,717,147)	(3,977,653)	(4,067,300)	(3,611,821)	(4,044,130)	(3,873,415)	(3,711,715)	(46,577,674)
12	9230	A&G-Outside services employed	85,332	57,130	52,402	61,634	103,506	59,968	50,422	48,472	46,025	32,386	34,086	31,000	662,361
13	9240	A&G-Property insurance	8,106	8,106	7,660	7,660	7,660	7,660	0	0	0	0	0	0	46,853
14	9250	A&G-Injuries & damages	17	17	17	0	0	0	0	0	0	0	0	0	52
15	9260	A&G-Employee pensions and benefits	823,774	704,864	579,503	731,730	834,566	715,362	839,343	877,906	756,941	867,377	823,530	787,853	9,342,751
16	9310	A&G-Rents	131,073	131,911	131,577	134,295	131,230	131,090	136,839	136,378	136,378	131,675	131,675	132,010	1,596,132
17	9320	A&G-Maintenance of general plant	2,009	56	935	0	0	968	3	3	6	4	4	9	3,997
18															
19		Operating (Income)Loss*	($0)	($0)	$0	$0	$0	$0	$0	$0	($0)	$0	($0)	($0)	$0
20															
21	9220	A&G-Administrative expense transferred-Credit	(4,107,536)	(3,616,023)	(3,896,279)	(3,884,435)	(4,070,220)	(3,717,147)	(3,977,653)	(4,067,300)	(3,611,821)	(4,044,130)	(3,873,415)	(3,711,715)	(46,577,674)
22		Allocation Factor to Kentucky	4.54%	4.50%	4.52%	4.49%	4.54%	4.38%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.07%
23		Total Allocated Amount	(186,586)	(162,752)	(176,247)	(174,271)	(184,807)	(162,958)	(224,388)	(229,445)	(203,751)	(228,138)	(218,508)	(209,386)	(2,361,238)
24															

*Note: Debits are shown as positive, and credits are shown as negatives. Includes the Shared Services allocation.

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Monthly Jurisdictional Operating Income by FERC Account, **Div 091 Only**
Base Period: Twelve Months Ended December 31, 2018

Data:___X____Base Period_________Forecasted Period — FR 16(8)(c)2.2
Type of Filing:___X____Original_________Updated _________Revised — Schedule C-2.2
Workpaper Reference No(s). — Witness: Waller, Densman

Line No.	Acct No.	Account Discription	actual Jan-18	actual Feb-18	actual Mar-18	actual Apr-18	actual May-18	actual Jun-18	Forecasted Jul-18	Forecasted Aug-18	Forecasted Sep-18	Budgeted Oct-18	Budgeted Nov-18	Budgeted Dec-18	Total
			$	$	$	$	$	$	$	$	$	$	$	$	$
1	4030	Depreciation Expense	(0)	(0)	(0)	(0)	(0)	0	0	0	0	0	0	0	0
2	4060	Amortization of gas plant acquisition adjustments	0	0	0	0	0	0							0
3	4081	Taxes other than income taxes, utility operating i	0	(0)	(0)	0	0	113,942	0	0	0	0	0	0	113,943
4	8170	Lines expenses	47	48	45	43	39	42	45	43	44	40	40	41	518
5	8180	Compressor station expenses	49	50	46	45	41	36	46	44	44	41	41	41	524
6	8190	Compressor station fuel and power	384	10	502	70	10	599	269	257	261	241	240	243	3,084
7	8210	Storage-Purification expenses	519	411	374	192	112	107	293	280	284	262	261	265	3,361
8	8240	Storage-Other expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
9	8250	Storage well royalties	3,345	957	2,384	3,109	841	572	1,913	1,826	1,855	1,711	1,705	1,728	21,945
	8500	Transmission-Operation supervision and engine	0	0	0	0	0	0	0	0	0	0	0	0	0
10	8560	Mains expenses	63	65	60	58	53	47	59	56	57	53	52	53	674
11	8570	Transmission-Measuring and regulating station e	94	97	89	87	79	83	90	86	87	81	80	82	1,035
12	8650	Transmission-Maintenance of me - Non-Inventor	0	0	0	0	0	445	66	74	58	40	70	97	850
13	8700	Distribution-Operation supervision and engineer	293,118	240,516	223,259	246,464	254,197	238,116	281,150	294,870	305,142	322,467	348,949	302,321	3,350,569
14	8711	Odorization	16,631	13,457	0	2,264	0	3,085	5,273	5,925	4,613	3,213	5,613	7,690	67,765
15	8740	Mains and Services Expenses	14,447	8,226	6,437	7,402	10,512	(11,155)	9,350	9,782	10,691	10,000	10,262	10,808	96,762
16	8750	Distribution-Measuring and regulating station ex	12,539	9,850	13,719	18,886	14,790	12,619	13,054	13,601	12,744	13,325	14,678	14,332	164,138
17	8760	Distribution-Measuring and regulating station ex	0	0	0	0	0	0	0	0	0	0	0	0	0
18	8770	Distribution-Measuring and regulating station ex	240	3,984	4,154	0	2,043	0	1,551	1,742	1,357	945	1,651	2,261	19,927
19	8800	Distribution-Other expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
20	8810	Distribution-Rents	23,863	23,776	23,073	21,788	23,332	23,466	23,784	22,695	23,054	21,271	21,189	21,480	272,771
21	9010	Customer accounts-Operation supervision	1,990	2,056	3,098	2,447	2,901	2,562	2,260	2,314	2,210	2,513	2,697	2,338	29,386
22	9020	Customer accounts-Meter reading expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
23	9030	Customer accounts-Customer records and collec	164,975	161,951	176,360	160,299	168,108	148,876	317,888	321,275	387,514	290,541	313,969	325,653	2,937,409
24	9100	Customer service-Miscellaneous customer servi	80	0	61	0	395	61	101	122	121	142	170	111	1,363
25	9110	Sales-Supervision	14,900	10,718	14,998	32,051	10,612	11,034	15,421	15,360	16,667	16,511	20,663	15,758	194,694
26	9120	Sales-Demonstrating and selling expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
27	9130	Sales-Advertising expenses	0	0	0	0	412	127	91	110	109	128	154	100	1,230
28	9200	A&G-Administrative & general salaries	(9,382)	(31,796)	(6,413)	(14,769)	(29,539)	(14,681)	7,981	7,915	10,225	1,359	654	755	(77,689)
29	9210	A&G-Office supplies & expense	25	281	1,997	0	0	50	471	438	610	466	785	468	5,592
30	9220	A&G-Administrative expense transferred-Credit	(756,390)	(597,520)	(734,179)	(668,458)	(750,312)	(600,333)	(1,001,651)	(857,469)	(934,152)	(895,868)	(971,966)	(944,580)	(9,712,877)
31	9230	A&G-Outside services employed	1,630	1,731	13,787	7,155	8,172	22,891	24,122	24,216	30,885	20,948	23,289	24,620	203,446
32	9240	A&G-Property insurance	(1,028)	(1,105)	(1,217)	(1,119)	(1,066)	(1,093)	(6,879)	(6,930)	(7,499)	(6,782)	(6,840)	(6,857)	(48,414)
33	9250	A&G-Injuries & damages	19,633	19,705	16,367	18,874	18,865	18,486	34,949	35,748	34,856	38,634	37,963	37,156	331,235
34	9260	A&G-Employee pensions and benefits	197,785	132,532	241,001	163,110	257,903	143,957	257,825	90,978	86,757	150,291	166,344	175,484	2,063,968
35	9280	A&G-Regulatory commission expenses	441	0	0	0	0	0	108	82	75	212	142	74	1,134
36	9302	Miscellaneous general expenses	0	0	0	0	7,500	0	10,370	14,559	11,331	7,214	7,144	7,479	65,598
37	9310	A&G-Rents	0	0	0	0	0	0	0	0	0	0	0	0	0
38															
39		Operating (Income)Loss*	$0	$0	$0	$0	$0	$113,942	$0	($0)	($0)	$0	($0)	($0)	($3,215,958)
40															
41	9220	A&G-Administrative expense transferred-Credit	(756,390)	(597,520)	(734,179)	(668,458)	(750,312)	(600,333)	(1,001,651)	(857,469)	(934,152)	(895,868)	(971,966)	(944,580)	(9,712,877)
42		Allocation Factor to Kentucky	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%
43		Total Allocated Amount	(376,531)	(297,446)	(365,474)	(332,758)	(373,505)	(298,846)	(498,622)	(426,848)	(465,021)	(445,963)	(483,845)	(470,212)	(4,835,070)

*Note: Debits are shown as positive, and credits are shown as negatives. Includes the Shared Services allocation.

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Monthly Jurisdictional Operating Income by FERC Account
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:________Base Period__X____Forecasted Period
Type of Filing:__X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(c)2.2
Schedule C-2.2
Witness: Waller, Densman

Line No.	Acct No.	Account Discription	Forecasted Apr-19	Forecasted May-19	Forecasted Jun-19	Forecasted Jul-19	Forecasted Aug-19	Forecasted Sep-19	Forecasted Oct-19	Forecasted Nov-19	Forecasted Dec-19	Forecasted Jan-20	Forecasted Feb-20	Forecasted Mar-20	Total
			$	$	$	$	$	$	$	$	$	$	$	$	$
1	4091	Provision for Federal & State Income Taxes	502,737	502,737	502,737	502,737	502,737	502,737	502,737	502,737	502,737	502,737	502,737	502,737	6,032,846
2															
3	4030	Depreciation Expense	1,925,175	1,925,175	1,925,175	1,925,175	1,925,175	1,925,175	1,925,175	1,925,175	1,925,175	1,925,175	1,925,175	1,925,175	23,102,096
4	4060	Amortization of gas plant acquisition adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
5	4081	Taxes other than income taxes, utility operating incor	640,835	738,129	594,669	612,104	591,163	611,801	608,409	662,710	585,360	647,320	601,852	617,486	7,511,837
6	4800	Residential sales	(8,610,670)	(5,415,767)	(4,024,680)	(3,684,913)	(3,686,810)	(3,665,404)	(4,813,510)	(8,164,047)	(12,309,251)	(15,261,501)	(15,293,972)	(11,588,966)	(96,519,490)
7	4805	Unbilled Residential Revenue													
8	4811	Commercial Revenue	(3,740,234)	(2,430,597)	(1,825,191)	(1,683,031)	(1,674,193)	(1,655,981)	(2,100,481)	(3,492,016)	(5,194,864)	(6,452,614)	(6,412,213)	(4,946,605)	(41,608,020)
9	4812	Industrial Revenue	(476,019)	(245,338)	(137,169)	(160,281)	(201,967)	(189,234)	(256,406)	(353,761)	(529,689)	(1,366,721)	(935,261)	(518,540)	(5,370,385)
10	4815	Unbilled Comm Revenue													
11	4816	Unbilled Industrial Revenue													
12	4820	Other Sales to Public Authorities	(608,129)	(347,107)	(235,663)	(213,588)	(213,629)	(204,562)	(309,465)	(584,748)	(914,867)	(1,137,917)	(1,135,614)	(844,518)	(6,749,807)
13	4825	Unbilled Public Authority Revenue													
14	4870	Forfeited discounts	(158,007)	(116,547)	(73,687)	(54,761)	(50,223)	(50,164)	(49,723)	(64,996)	(110,128)	(165,694)	(205,564)	(205,470)	(1,304,965)
15	4880	Miscellaneous service revenues	(49,919)	(53,628)	(55,397)	(45,327)	(57,173)	(55,395)	(88,176)	(126,545)	(87,101)	(58,133)	(54,439)	(74,821)	(806,054)
16	4893	Revenue-Transportation Commercial	(1,283,037)	(1,128,527)	(1,043,108)	(994,105)	(1,088,324)	(1,079,966)	(1,210,609)	(1,304,753)	(1,422,620)	(1,613,292)	(1,319,597)	(1,393,444)	(14,881,382)
17	4950	Other Gas Revenue	(209,397)	(195,682)	(179,746)	(157,141)	(159,212)	(171,560)	(201,623)	(213,081)	(245,950)	(268,663)	(230,460)	(245,247)	(2,477,763)
18	4960	Provision for Rate Refunds													0
19	7560	Field measuring and regulating station expenses	-	-	-	-	-	-	-	-	-	-	-	-	0
20	7590	Production and gathering-Other	-	-	-	-	-	-	-	-	-	-	-	-	0
21	8001	Intercompany Gas Well-head Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
22	8010	Natural gas field line purchases	3,587	6,498	6,067	6,533	5,609	5,836	6,647	4,208	3,911	3,186	4,968	4,191	61,240
23	8040	Natural gas city gate purchases	790,374	8,617,999	5,454,286	5,157,504	3,479,428	3,137,525	3,473,123	4,704,009	2,170,949	4,770,003	7,781,592	1,864,528	51,401,318
24	8050	Other purchases	(1,129)	(91)	0	(262)	(708)	(1,713)	(1,037)	(70)	(1,234)	(799)	(301)	(257)	(7,602)
25	8051	PGA for Residential	5,479,165	3,599,785	927,599	751,202	639,510	662,747	692,875	2,727,290	5,076,966	9,419,574	12,045,677	5,495,037	47,517,427
26	8052	PGA for Commercial	2,504,115	1,997,380	820,666	675,566	667,067	760,554	774,005	1,431,038	2,370,833	4,356,115	5,641,450	2,565,524	24,564,311
27	8053	PGA for Industrial	452,927	468,624	176,125	157,955	151,778	131,464	180,269	222,788	310,262	645,928	1,306,609	649,413	4,854,142
28	8054	PGA for Public Authorities	486,525	416,845	160,924	106,502	104,668	91,426	122,222	267,896	448,227	786,578	1,107,854	485,814	4,585,482
29	8058	Unbilled PGA Cost	(1,786,375)	(2,960,757)	(151,497)	(69,225)	86,076	(4,087)	1,169,934	1,933,648	3,006,709	(96,326)	(5,403,032)	1,150,255	(3,124,678)
30	8059	PGA Offset to Unrecovered Gas Cost	(7,613,425)	(8,532,908)	(3,481,430)	(2,620,777)	(2,114,863)	(2,028,834)	(2,370,175)	(3,438,993)	(5,516,847)	(9,464,121)	(16,862,796)	(7,781,002)	(71,826,171)
31	8060	Exchange gas	1,231,297	(1,368,386)	(1,501,513)	(2,492,092)	(1,552,662)	(923,458)	(1,057,483)	(1,198,976)	417,908	1,698,160	3,040,344	1,559,522	(2,147,338)
32	8081	Gas withdrawn from storage-Debit	3,565,807	134,253	0	0	209	0	0	18,127	1,378,297	1,623,795	3,203,606	2,511,942	12,436,037
33	8082	Gas delivered to storage-Credit	(58,250)	(1,853,715)	(2,372,686)	(1,613,551)	(1,202,402)	(1,406,160)	(1,329,056)	(1,723,603)	(305,776)	(590,083)	(93,554)	(77,899)	(12,626,734)
34	8120	Gas used for other utility operations-Credit	(3,252)	(1,499)	7,996	678	178	1,093	(8,977)	7,397	(2,858)	(2,871)	(5,483)	(6,731)	(14,329)
35	8580	Transmission and compression of gas by others	2,081,739	2,996,349	1,895,277	1,562,644	1,385,389	1,216,803	1,277,981	1,635,300	1,852,792	1,959,859	2,926,142	1,918,975	22,709,250
36	8140	Storage-Operation supervision and engineering	-	-	-	-	-	-	-	-	-	-	-	-	0
37	8160	Wells expenses	31,298	24,253	30,923	28,122	31,187	25,335	20,821	20,501	16,408	19,192	16,767	27,110	291,917
38	8170	Lines expenses	1,775	1,785	1,617	1,787	1,730	1,638	1,865	1,851	1,764	1,970	1,715	1,753	21,251
39	8180	Compressor station expenses	2,305	2,038	1,907	2,266	2,137	1,851	2,105	2,111	1,863	2,305	2,027	2,144	25,060
40	8190	Compressor station fuel and power	63	61	60	54	60	57	58	64	64	69	61	65	735
41	8200	Storage-Measuring and regulating station expenses	589	509	555	551	575	496	485	490	436	501	446	547	6,181
42	8210	Storage-Purification expenses	4,313	4,144	3,798	4,312	4,130	3,791	4,313	4,289	3,981	4,601	4,020	4,164	49,856
43	8240	Storage-Other expenses	-	-	-	-	-	-	-	-	-	-	-	-	0
44	8250	Storage well royalties	747	725	714	645	718	676	690	762	763	827	726	770	8,763
45	8310	Storage-Maintenance of structures and improvement	1,373	1,044	1,388	1,244	1,385	1,110	894	879	695	796	735	1,195	12,736
46	8340	Maintenance of compressor station equipment	273	282	252	280	269	259	297	291	280	308	268	272	3,331
47	8350	Maintenance of measuring and regulating station equ	-	-	-	-	-	-	-	-	-	-	-	-	0
48	8360	Processing-Maintenance of purification equipment	-	-	-	-	-	-	-	-	-	-	-	-	0
49	8370	Maintenance of other equipment	-	-	-	-	-	-	-	-	-	-	-	-	0
50	8410	Other storage expenses-Operation labor and expens	5,751	5,789	5,224	5,756	5,601	5,421	6,094	6,097	5,750	6,354	5,560	5,686	69,083
51	8500	Transmission-Operation supervision and engineering	4	3	3	4	3	2	3	3	2	3	3	3	35
52	8520	Communication system expenses	-	-	-	-	-	-	-	-	-	-	-	-	0
53	8550	Other fuel and power for Compression	26	26	25	23	25	24	24	27	27	29	26	27	308
54	8560	Mains expenses	33,952	30,334	31,661	32,800	33,171	29,203	29,824	29,566	26,617	30,410	26,935	31,730	366,202
55	8570	Transmission-Measuring and regulating station exper	2,271	2,291	2,099	2,240	2,217	2,109	2,364	2,380	2,295	2,536	2,209	2,267	27,278
56	8630	Transmission-Maintenance of mains	1,304	1,313	1,295	1,372	1,282	1,265	1,430	1,370	1,471	1,469	1,334	1,374	16,280
57	8640	Transmission-Maintenance of compressor sta equipr	-	-	-	-	-	-	-	-	-	-	-	-	0
58	8650	Transmission-Maintenance of measuring and regulat	-	-	-	-	-	-	-	-	-	-	-	-	0

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Monthly Jurisdictional Operating Income by FERC Account
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:________Base Period___X____Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(c)2.2
Schedule C-2.2
Witness: Waller, Densman

Line No.	Acct No.	Account Discription	Forecasted Apr-19	Forecasted May-19	Forecasted Jun-19	Forecasted Jul-19	Forecasted Aug-19	Forecasted Sep-19	Forecasted Oct-19	Forecasted Nov-19	Forecasted Dec-19	Forecasted Jan-20	Forecasted Feb-20	Forecasted Mar-20	Total
			$	$	$	$	$	$	$	$	$	$	$	$	$
59	8700	Distribution-Operation supervision and engineering	95,363	82,927	81,809	87,702	87,419	86,667	72,471	75,617	68,886	81,362	57,661	85,527	963,411
60	8710	Distribution load dispatching	56	55	54	49	54	51	52	58	58	63	55	58	663
61	8711	Odorization	2,139	1,517	1,487	2,007	1,818	1,334	1,530	1,594	1,194	1,853	1,659	1,824	19,956
62	8720	Distribution-Compressor station labor and expenses	-	-	-	-	-	-	-	-	-	-	-	-	0
63	8740	Mains and Services Expenses	405,494	363,133	367,663	384,796	387,859	354,743	339,766	343,529	318,227	355,552	320,082	379,874	4,320,719
64	8750	Distribution-Measuring and regulating station expens	50,709	47,612	45,168	49,809	48,525	44,745	49,054	48,933	44,962	51,455	45,286	48,455	574,714
65	8760	Distribution-Measuring and regulating station expens	9,933	10,174	9,200	10,184	9,762	9,377	10,749	10,539	10,193	11,171	9,741	9,905	120,928
66	8770	Distribution-Measuring and regulating station expens	4,040	3,056	3,580	3,697	3,816	3,009	2,810	2,861	2,278	2,941	2,662	3,537	38,286
67	8780	Meter and house regulator expenses	68,454	68,892	62,687	68,135	66,436	64,783	72,241	71,914	68,585	75,107	65,784	67,604	820,621
68	8790	Customer installations expenses	241	171	167	226	205	150	172	179	134	209	187	205	2,246
69	8800	Distribution-Other expenses	325	161	323	287	228	254	203	172	380	259	237	374	3,204
70	8810	Distribution-Rents	31,417	30,348	30,403	27,253	30,120	28,504	29,057	31,809	32,705	34,779	30,654	32,718	369,768
71	8850	Distribution-Maintenance supervision and engineerin	92	38	209	144	83	122	107	57	278	92	165	200	1,588
72	8860	Distribution-Maintenance of structures and improvem	11	7	7	10	9	7	8	8	6	9	8	9	98
73	8870	Distribution-Maint of mains	2,529	2,425	2,402	2,509	2,510	2,304	2,451	2,406	2,238	2,476	2,172	2,431	28,852
74	8890	Maintenance of measuring and regulating station equ	5,626	5,458	4,992	5,594	5,398	4,992	5,667	5,666	5,309	6,084	5,311	5,477	65,572
75	8900	Maintenance of measuring and regulating station equ	168	137	129	163	150	122	140	143	119	160	141	151	1,723
76	8910	Maintenance of measuring and regulating station equ	68	66	65	58	65	61	63	69	69	75	66	70	795
77	8920	Maintenance of services	537	552	495	549	528	507	582	572	548	605	525	533	6,533
78	8930	Maintenance of meters and house regulators	-	-	-	-	-	-	-	-	-	-	-	-	0
79	8940	Distribution-Maintenance of other equipment	628	447	437	590	534	393	449	468	351	545	488	536	5,866
80	9010	Customer accounts-Operation supervision	-	-	-	-	-	-	-	-	-	-	-	-	0
81	9020	Customer accounts-Meter reading expenses	101,860	91,690	100,423	100,350	102,527	91,806	84,755	83,287	75,580	83,721	74,773	94,274	1,085,047
82	9030	Customer accounts-Customer records and collection	120,600	101,159	119,241	113,238	120,905	102,644	93,660	92,059	79,268	88,775	79,888	109,365	1,220,802
83	9040	Customer accounts-Uncollectible accounts	22,446	10,897	20,882	20,241	20,817	20,056	28,172	39,073	52,615	41,449	20,234	44,169	341,050
84	9090	Customer service-Operating informational and instruc	11,052	10,664	9,744	10,252	10,268	10,558	11,078	11,384	10,701	11,584	10,285	10,702	128,272
85	9100	Customer service-Miscellaneous customer service	-	-	-	-	-	-	-	-	-	-	-	-	0
86	9110	Sales-Supervision	22,227	20,874	19,322	19,909	20,208	21,279	21,599	22,552	21,146	22,649	20,329	21,374	253,468
87	9120	Sales-Demonstrating and selling expenses	7,941	6,529	6,575	8,470	12,396	8,211	9,828	17,667	6,973	10,653	10,030	10,663	115,937
88	9130	Sales-Advertising expenses	2,261	2,034	1,926	2,650	3,938	2,583	2,786	5,444	2,060	3,034	3,127	3,327	35,170
89	9200	A&G-Administrative & General Salaries	10,496	10,875	9,733	10,765	10,360	9,991	11,469	11,253	10,827	11,890	10,321	10,460	128,440
90	9210	A&G-Office supplies & expense	1,622	1,262	1,290	1,211	1,509	1,612	1,353	1,810	1,456	1,417	1,480	1,594	17,616
91	9220	A&G-Administrative expense transferred-Credit	1,200,012	1,410,253	1,126,527	1,355,808	1,074,751	1,114,812	1,150,349	1,177,101	1,160,596	1,258,873	1,168,001	1,301,683	14,498,764
92	9230	A&G-Outside services employed	36,621	27,876	37,172	33,168	37,019	29,690	23,808	23,388	18,509	21,094	19,476	31,877	339,697
93	9240	A&G-Property insurance	147	-	-	-	968	-	127	-	2,476	-	-	-	3,718
94	9250	A&G-Injuries & damages	7,589	5,961	7,749	6,930	7,850	6,362	5,380	5,618	4,333	4,930	4,515	6,794	74,010
95	9260	A&G-Employee pensions and benefits	153,585	160,208	144,233	156,546	151,618	147,825	151,848	150,004	144,874	157,964	136,688	135,889	1,791,281
96	9270	A&G-Franchise requirements	42	37	35	49	72	47	51	100	38	56	57	61	646
97	9280	A&G-Regulatory commission expenses	57,070	55,064	54,779	55,372	54,701	54,258	54,210	56,040	52,179	55,262	69,770	53,288	671,994
98	9302	Miscellaneous general expenses	8,307	1,083	2,344	(494)	(5)	(633)	11,123	7,551	913	12,043	(146)	(328)	41,757
99	9310	A&G-Rents	946	919	904	816	910	856	874	965	966	1,048	920	976	11,100
100	9320	A&G-Maintenance of general plant	2,049	448	732	107	209	71	2,658	1,877	410	2,865	240	138	11,804
101		Operating (Income)Loss*	($2,905,556)	($1,139,904)	($756,577)	($212,586)	($604,881)	($594,701)	($1,242,116)	($2,751,556)	($4,828,942)	($6,157,568)	($6,131,316)	($4,380,743)	($25,673,600)

*Note: Debits are shown as positive, and credits are shown as negatives. Includes the Shared Services allocation.
**Note: Provision for Income Taxes is not a component of Operating Income but is included on this schedule to develop the 12 month total for use elsewhere in the model

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Monthly Jurisdictional Operating Income by FERC Account, **Div 002 Only**
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:________Base Period___X____Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(c)2.2
Schedule C-2.2
Witness: Waller, Densman

Line No.	Acct No.	Account Discription	Forecasted Apr-19	Forecasted Jun-19	Forecasted Jun-19	Forecasted Jul-19	Forecasted Aug-19	Forecasted Sep-19	Forecasted Oct-19	Forecasted Nov-19	Forecasted Dec-19	Forecasted Jan-20	Forecasted Feb-20	Forecasted Mar-20	Total
			$	$	$	$	$	$	$	$	$	$	$	$	$
1	4030	Depreciation Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
2	4081	Taxes other than income taxes, utility operating i	0	0	0	0	0	0	0	0	0	0	0	0	0
3	8210	Storage-Purification expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
4	8560	Mains expenses	1,291	1,349	1,174	1,349	1,291	1,232	1,396	1,335	1,275	1,390	1,209	1,269	15,559
5	8700	Distribution-Operation supervision and engineerir	40,289	42,176	40,148	42,878	40,508	43,400	43,510	41,950	40,366	41,070	39,694	41,180	497,169
6	8740	Mains and Services Expenses	6,227	6,227	6,227	6,227	6,227	6,231	6,227	6,227	6,227	6,227	6,227	6,227	74,734
7	8780	Meter and house regulator expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
8	8800	Distribution-Other expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
9	8850	Maintenance Supervision and Engineering	16,990,315	21,798,985	16,389,216	20,381,249	15,192,473	15,531,582	16,712,710	16,588,629	16,696,241	17,593,151	16,611,593	19,213,246	209,699,389
9	8900	Maintenance of measuring and regulating station	0	0	0	0	0	0	0	0	0	0	0	0	0
10	9010	Customer accounts-Operation supervision	0	0	0	0	0	0	0	0	0	0	0	0	0
11	9030	Customer accounts-Customer records and collec	9,321	9,741	8,488	9,742	9,319	8,907	10,079	9,641	9,216	10,038	8,733	9,303	112,527
12	9100	Customer service-Miscellaneous customer servic	0	0	0	0	0	0	0	0	0	0	0	0	0
13	9120	Sales-Demonstrating and selling	1,593	1,799	1,675	1,593	2,499	1,674	2,005	1,757	2,643	1,980	1,753	1,716	22,686
14	9160	Miscellaneous Sales Expenses	435	456	450	467	439	493	470	454	439	433	438	452	5,426
15	9200	A&G-Administrative & general salaries	(18,260,638)	(24,467,023)	(17,831,030)	(22,575,207)	(15,870,304)	(16,493,103)	(17,553,877)	(17,588,997)	(17,922,016)	(18,746,428)	(18,020,906)	(21,273,611)	(226,603,141)
16	9210	A&G-Office supplies & expense	2,961,646	2,919,576	2,878,834	3,089,375	3,095,164	3,165,939	2,925,307	2,709,077	2,859,363	2,807,137	2,789,647	2,896,749	35,097,814
17	9220	A&G-Administrative expense transferred-Credit	(8,659,768)	(11,774,278)	(8,664,346)	(11,298,399)	(8,041,713)	(7,958,613)	(9,028,379)	(9,016,520)	(9,152,630)	(9,354,525)	(8,848,780)	(11,046,379)	(112,844,330)
18	9230	A&G-Outside services employed	932,826	921,309	998,989	963,271	932,153	1,040,510	903,707	881,820	924,838	897,385	945,742	1,016,812	11,359,362
19	9240	A&G-Property insurance	11,976	11,976	11,976	11,976	12,107	11,976	11,863	11,969	11,969	11,969	11,969	11,976	143,704
20	9250	A&G-Injuries & damages	1,686,726	1,687,242	1,685,693	1,687,242	1,704,969	1,686,210	1,672,097	1,686,412	1,685,858	1,686,907	1,685,253	1,686,808	20,241,417
21	9260	A&G-Employee pensions and benefits	3,402,369	8,016,562	3,349,039	6,845,160	2,080,046	1,901,297	3,454,171	3,850,403	3,782,486	4,126,700	3,855,384	3,541,568	48,205,185
22	9301	A&G-General advertising expense	0	0	0	0	0	0	0	0	0	0	0	0	0
23	9302	Miscellaneous general expenses	327,410	278,765	576,120	282,923	287,542	492,583	261,299	243,628	509,151	372,134	368,289	3,345,372	7,345,216
24	9310	A&G-Rents	504,803	503,216	504,763	505,292	502,615	514,624	534,953	532,113	502,561	503,531	502,362	504,956	6,115,788
25	9320	A&G-Maintenance of general plant	43,177	41,920	42,584	44,863	44,665	45,057	42,464	40,101	42,014	40,902	41,393	42,355	511,495
26		Operating (Income)Loss*	$0	($0)	$0	($0)	($0)	$0	$0	$0	($0)	($0)	$0	($0)	($0)
27															
28	9220	A&G-Administrative expense transferred-Credit	(8,659,768)	(11,774,278)	(8,664,346)	(11,298,399)	(8,041,713)	(7,958,613)	(9,028,379)	(9,016,520)	(9,152,630)	(9,354,525)	(8,848,780)	(11,046,379)	
29		Allocation Factor to Kentucky	5.18%	5.18%	5.18%	5.18%	5.18%	5.18%	5.18%	5.18%	5.18%	5.18%	5.18%	5.18%	
30		Total Allocated Amount	(448,327)	(609,568)	(448,564)	(584,932)	(416,329)	(412,027)	(467,410)	(466,796)	(473,843)	(484,295)	(458,112)	(571,884)	(5,842,086)

*Note: Debits are shown as positive, and credits are shown as negatives. Includes the Shared Services allocation.

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Monthly Jurisdictional Operating Income by FERC Account, **Div 012 Only**
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:________Base Period___X____Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(c)2.2
Schedule C-2.2
Witness: Waller, Densman

Line No.	Acct No.	Account Discription	Forecasted Apr-19	Forecasted Jun-19	Forecasted Jun-19	Forecasted Jul-19	Forecasted Aug-19	Forecasted Sep-19	Forecasted Oct-19	Forecasted Nov-19	Forecasted Dec-19	Forecasted Jan-20	Forecasted Feb-20	Forecasted Mar-20	Total
			$	$	$	$	$	$	$	$	$	$	$	$	$
1	4030	Depreciation Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
2	4081	Taxes other than income taxes, utility operating income	0	0	0	0	0	0	0	0	0	0	0	0	0
3	8700	Distribution-Operation supervision and engineering	877	877	898	1,061	925	933	851	851	985	816	799	819	10,693
4	8740	Mains and Services Expenses	1,724	1,724	1,724	1,724	1,724	1,728	1,724	1,724	1,724	1,724	1,724	1,724	20,691
5	8800	Distribution-Other expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
6	9010	Customer accounts-Operation supervision	429,246	488,642	397,439	520,253	406,721	395,229	446,162	443,807	423,316	463,229	403,395	421,220	5,238,660
7	9020	Customer accounts-Meter reading expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
8	9030	Customer accounts-Customer records and collections	1,953,200	2,024,086	1,758,263	2,023,940	1,868,749	1,789,056	2,043,759	1,935,312	1,847,161	2,097,861	1,804,683	1,890,663	23,036,731
9	9200	A&G-Administrative & general salaries	428,436	449,007	390,796	439,296	416,815	398,151	449,190	430,392	410,711	460,938	402,418	421,849	5,097,999
10	9210	A&G-Office supplies & expense	205,079	144,142	178,979	161,164	161,173	244,022	153,090	150,562	151,916	145,723	147,840	162,220	2,005,910
11	9220	A&G-Administrative expense transferred-Credit	(4,068,862)	(4,142,197)	(3,661,550)	(4,151,580)	(3,862,146)	(3,852,219)	(4,175,633)	(3,999,217)	(3,831,817)	(4,264,250)	(3,741,713)	(3,928,703)	(47,679,887)
12	9230	A&G-Outside services employed	67,096	28,306	26,655	34,296	40,739	97,310	32,386	34,086	31,000	24,405	29,593	38,476	484,348
13	9240	A&G-Property insurance	0	0	0	0	0	0	0	0	0	0	0	0	0
14	9250	A&G-Injuries & damages	0	0	0	0	0	0	0	0	0	0	0	0	0
15	9260	A&G-Employee pensions and benefits	851,524	873,733	774,709	838,168	833,621	793,775	916,793	870,804	832,985	937,873	819,581	859,713	10,203,278
16	9310	A&G-Rents	131,675	131,675	132,010	131,675	131,675	132,008	131,675	131,675	132,010	131,675	131,675	132,010	1,581,442
17	9320	A&G-Maintenance of general plant	4	4	77	4	4	8	4	4	9	5	4	9	135
18															
19	Operating (Income)Loss*		$0	($0)	($0)	$0	$0	($0)	$0	$0	($0)	($0)	($0)	($0)	($0)
20															
21	9220	A&G-Administrative expense transferred-Credit	(4,068,862)	(4,142,197)	(3,661,550)	(4,151,580)	(3,862,146)	(3,852,219)	(4,175,633)	(3,999,217)	(3,831,817)	(4,264,250)	(3,741,713)	(3,928,703)	(47,679,887)
22		Allocation Factor to Kentucky	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	
23		Total Allocated Amount	(229,533)	(233,670)	(206,556)	(234,200)	(217,872)	(217,312)	(235,557)	(225,605)	(216,161)	(240,556)	(211,078)	(221,627)	(2,689,726)

*Note: Debits are shown as positive, and credits are shown as negatives. Includes the Shared Services allocation.

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Monthly Jurisdictional Operating Income by FERC Account, **Div 091 Only**
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:________Base Period___X____Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(c)2.2
Schedule C-2.2
Witness: Waller, Densman

Line No.	Acct No.	Account Discription	Forecasted Apr-19	Forecasted Jun-19	Forecasted Jun-19	Forecasted Jul-19	Forecasted Aug-19	Forecasted Sep-19	Forecasted Oct-19	Forecasted Nov-19	Forecasted Dec-19	Forecasted Jan-20	Forecasted Feb-20	Forecasted Mar-20	Total
			$	$	$	$	$	$	$	$	$	$	$	$	$
1	4030	Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
2	4060	Amortization of gas plant acquisition adjustments													
3	4081	Taxes other than income taxes, utility operating i	-	-	-	-	-	-	-	-	-	-	-	-	-
4	8170	Lines expenses	42	40	39	52	41	40	40	40	41	43	44	43	506
5	8180	Compressor station expenses	43	40	40	53	42	40	41	41	41	44	44	44	512
6	8190	Compressor station fuel and power	251	236	235	310	244	237	241	240	243	256	261	259	3,013
7	8210	Storage-Purification expenses	274	258	256	338	266	258	262	261	265	279	284	282	3,283
8	8240	Storage-Other expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
9	8250	Storage well royalties	1,786	1,682	1,674	2,206	1,738	1,687	1,711	1,705	1,728	1,824	1,854	1,841	21,436
10	8500	Transmission-Operation supervision and engine	0	0	0	0	0	0	0	0	0	0	0	0	0
11	8560	Mains expenses	55	52	51	68	53	52	53	52	53	56	57	57	658
12	8570	Transmission-Measuring and regulating station e	84	79	79	104	82	80	81	80	82	86	87	87	1,011
13	8650	Transmission-Maintenance of me - Non-Inventor	82	46	58	40	58	47	40	70	97	83	109	63	793
14	8700	Distribution-Operation supervision and engineer	363,370	330,919	307,582	323,443	319,922	340,520	326,573	352,877	306,072	351,955	319,566	333,577	3,976,375
15	8711	Odorization	6,550	3,639	4,587	3,193	4,656	3,724	3,213	5,613	7,690	6,602	8,683	5,015	63,165
16	8740	Mains and Services Expenses	11,475	11,449	11,435	11,774	12,952	12,332	10,000	10,263	10,808	12,208	11,490	10,690	136,876
17	8750	Distribution-Measuring and regulating station ex	15,088	14,175	13,201	13,394	13,711	13,936	13,621	14,961	14,602	15,582	14,794	14,046	171,111
18	8760	Distribution-Measuring and regulating station ex	0	0	0	0	0	0	0	0	0	0	0	0	0
19	8770	Distribution-Measuring and regulating station ex	1,926	1,070	1,349	939	1,369	1,095	945	1,651	2,261	1,941	2,553	1,475	18,575
20	8800	Distribution-Other expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
21	8810	Distribution-Rents	22,196	20,908	20,813	27,424	21,601	20,967	21,271	21,189	21,480	22,667	23,044	22,878	266,438
22	9010	Customer accounts-Operation supervision	2,606	2,527	2,338	2,478	2,444	2,572	2,576	2,758	2,396	2,680	2,320	2,449	30,145
23	9020	Customer accounts-Meter reading expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
24	9030	Customer accounts-Customer records and collec	377,114	417,776	355,006	323,143	331,170	401,813	292,344	315,693	327,300	377,775	367,597	380,005	4,266,733
25	9100	Customer service-Miscellaneous customer servi	239	120	110	109	114	118	142	170	111	122	132	130	1,616
26	9110	Sales-Supervision	19,147	16,740	16,891	15,911	16,487	19,717	16,808	20,947	16,030	18,521	15,890	16,920	210,011
27	9120	Sales-Demonstrating and selling expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
28	9130	Sales-Advertising expenses	215	108	99	98	103	107	128	154	100	110	119	117	1,458
29	9200	A&G-Administrative & general salaries	1,421	1,420	667	2,034	654	864	1,359	654	755	654	1,066	6,272	17,821
30	9210	A&G-Office supplies & expense	676	478	580	419	488	746	466	785	468	583	487	529	6,705
31	9220	A&G-Administrative expense transferred-Credit	(1,048,918)	(1,139,041)	(946,981)	(1,078,097)	(884,993)	(975,237)	(898,720)	(973,685)	(945,344)	(1,072,764)	(1,002,031)	(1,020,835)	(11,986,644)
32	9230	A&G-Outside services employed	29,052	32,533	27,519	23,922	24,881	31,531	20,948	23,289	24,620	28,720	28,532	29,415	324,964
33	9240	A&G-Property insurance	(7,314)	(7,153)	(7,152)	(7,102)	(7,120)	(7,152)	(6,782)	(6,840)	(6,857)	(7,073)	(6,902)	(7,160)	(84,606)
34	9250	A&G-Injuries & damages	38,899	39,392	36,867	39,261	38,440	37,677	37,671	36,780	35,799	38,281	34,878	36,432	450,378
35	9260	A&G-Employee pensions and benefits	154,857	224,404	145,260	282,772	82,187	79,832	147,541	162,965	171,607	191,431	166,790	157,794	1,967,441
36	9280	A&G-Regulatory commission expenses	73	83	126	64	70	68	212	142	74	172	54	69	1,208
37	9302	Miscellaneous general expenses	8,710	26,021	7,267	11,651	18,338	12,328	7,214	7,144	7,479	7,162	8,198	7,506	129,018
38	9310	A&G-Rents	0	0	0	0	0	0	0	0	0	0	0	0	0
39															
40	Operating (Income)Loss*		$0	($0)	($0)	($0)	$0	$0	$0	($0)	($0)	($0)	$0	($0)	$0
41															
42	9220	A&G-Administrative expense transferred-Credit	(1,048,918)	(1,139,041)	(946,981)	(1,078,097)	(884,993)	(975,237)	(898,720)	(973,685)	(945,344)	(1,072,764)	(1,002,031)	(1,020,835)	(11,986,644)
43		Allocation Factor to Kentucky	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%
44		Total Allocated Amount	(522,152)	(567,014)	(471,407)	(536,676)	(440,549)	(485,473)	(447,383)	(484,700)	(470,592)	(534,022)	(498,811)	(508,172)	(5,966,951)

*Note: Debits are shown as positive, and credits are shown as negatives. Includes the Shared Services allocation.

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Account 4081-Taxes Other than Income Tax by Sub-Account
Base Period: Twelve Months Ended December 31, 2018

Data:___X____Base Period________Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(c)2.3
Schedule C-2.3 B
Witness: Waller

Line No.	Discription	actual Jan-18	actual Feb-18	actual Mar-18	actual Apr-18	actual May-18	actual Jun-18	Forecasted Jul-18	Forecasted Aug-18	Forecasted Sep-18	Budgeted Oct-18	Budgeted Nov-18	Budgeted Dec-18	Total
	Div 009													
1														
2														
3	Payroll	$ 43,715	$ 22,051	$ 44,849	$ 19,472	$ 23,062	$ 24,167	$ 25,815	$ 16,772	$ 47,927	$ 17,707	$ 62,409	$ 10,269	$ 358,215
4	Payroll Tax Projects	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0
5	Ad Valorem - Accrual	$418,588	$ 418,588	$ 418,588	$ 418,588	$ 418,588	$ 418,588	$ 410,845	$ 410,845	$ 410,841	$ 485,000	$ 485,000	$ 485,000	5,199,059
6	Dot Transmission User Tax	$ -	$ -	$ -	$ -	$ 137,062	$ -	$ -	$ -	$ -	$ -	$ -	$ -	137,062
7	Taxes Property and Other	$ 22,305	$ -	$ 2,869	$ 45,644	$ 43	$ -	$ 15,032	$ 191	$ 47,280	$ 11,110	$ 66	$ 338	144,877
8	Public Service Commission Assessment	$ 24,523	$ 24,523	$ 24,523	$ 24,523	$ 24,523	$ 24,523	$ 26,088	$ 26,088	$ 26,088	$ 27,296	$ 27,296	$ 27,296	307,288
9	Allocation for taxes other CSC	$ 16,727	$ 11,571	$ 13,828	$ 12,398	$ 15,152	$ 11,197	15,400	15,400	15,400	15,512	15,512	15,512	173,608
10	Allocation from taxes other SS	$ 21,551	$ 15,313	$ 15,559	$ 16,301	$ 20,184	$ (41,810)	22,152	22,152	22,152	23,138	23,138	23,138	182,969
11	Allocation from taxes other Gen Office	$ 18,809	$ (179,541)	$ 7,557	$ 16,025	$ 18,266	$ 15,729	6,203	4,651	12,071	18,155	36,895	13,674	(11,505)
12														
13	Total	$566,216	$ 312,504	$ 527,772	$ 552,951	$ 656,880	$ 452,394	$ 521,535	$ 496,100	$ 581,759	$ 597,919	$ 650,316	$ 575,228	$ 6,491,574
14														
15	**Div 002**													
16														
17														
18	Payroll	$346,571	$ 226,079	$ 217,302	$ 244,421	$ 335,873	$ 218,311	$ 338,716	$ 338,716	$ 338,716	$ 353,794	$ 353,794	$ 353,794	3,666,089
19	Ad Valorem	$ 69,700	$ 69,700	$ 69,700	$ 69,700	$ 69,700	$ 69,700	$ 89,170	$ 89,170	$ 89,170	$ 93,139	$ 93,139	$ 93,139	965,126
20	Payroll Tax Projects	$ -	$ -	$ 13,529	$ 743	$ 152	$ -	$ -	$ -	$ -	$ -	$ -	$ -	14,424
21	Taxes Property And Other	$ -	$ -	$ -	$ -	$ (15,846)	$(1,095,601)	$ -	$ -	$ -	$ -	$ -	$ -	(1,111,447)
22														
23	Total Tax Other Than Income Tax	$416,271	$ 295,779	$ 300,531	$ 314,864	$ 389,879	$ (807,590)	$ 427,886	$ 427,886	$ 427,886	$ 446,933	$ 446,933	$ 446,933	$ 3,534,192
24														
25	Allocation Factor to Kentucky Mid-States (Div 091)							10.40%	10.40%	10.40%	10.40%	10.40%	10.40%	
26	Allocation Factor to Kentucky Jurisdiction (Div 009)							49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	
27														
28	Total Allocated Amount	$ 21,551	$ 15,313	$ 15,559	$ 16,301	$ 20,184	$ (41,810)	$ 22,152	$ 22,152	$ 22,152	$ 23,138	$ 23,138	$ 23,138	$ 182,969
29														
30	**Div 012**													
31														
32														
33	Payroll	$243,898	$ 152,509	$ 192,506	$ 167,175	$ 215,981	$ 145,881	$ 212,892	$ 212,892	$ 212,892	$ 222,369	$ 222,369	$ 222,369	2,423,734
34	Ad Valorem	$ 52,600	$ 52,600	$ 52,600	$ 52,600	$ 52,600	$ 52,600	$ 60,100	$ 60,100	$ 60,100	$ 52,600	$ 52,600	$ 52,600	653,700
35														
36	Total Tax Other Than Income Tax	$296,498	$ 205,109	$ 245,106	$ 219,775	$ 268,581	$ 198,481	$ 272,992	$ 272,992	$ 272,992	$ 274,969	$ 274,969	$ 274,969	$ 3,077,434
37														
38	Allocation Factor to Kentucky Mid-States (Div 091)							10.95%	10.95%	10.95%	10.95%	10.95%	10.95%	
39	Allocation Factor to Kentucky Jurisdiction (Div 009)							51.52%	51.52%	51.52%	51.52%	51.52%	51.52%	
40														
41	Total Allocated Amount	$ 16,727	$ 11,571	$ 13,828	$ 12,398	$ 15,152	$ 11,197	$ 15,400	$ 15,400	$ 15,400	$ 15,512	$ 15,512	$ 15,512	$ 173,608
42														
43	**Div 091**													
44														
45														
46	Payroll	$ 37,484	$ 35,784	$ 14,840	$ 31,891	$ 36,394	$ 30,796	$ 11,661	$ 8,544	$ 23,449	$ 35,671	$ 73,316	$ 26,670	$ 366,499
47	Payroll Tax Projects	$ -	$ 21	$ 42	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	63
48	Ad Valorem	$ 300	$ (396,474)	$ 300	$ 300	$ 300	$ 800	$ 800	$ 800	$ 800	$ 800	$ 800	$ 800	(389,674)
49	Occupational Licenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0
50														
51	Total Tax Other Than Income Tax	$ 37,784	$ (360,670)	$ 15,181	$ 32,191	$ 36,694	$ 31,596	$ 12,461	$ 9,344	$ 24,249	$ 36,471	$ 74,116	$ 27,470	$ (23,112)
52														
53	Allocation Factor to Kentucky Mid-States (Div 091)							100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
54	Allocation Factor to Kentucky Jurisdiction (Div 009)							49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	
55														
56	Total Allocated Amount	$ 18,809	$ (179,541)	$ 7,557	$ 16,025	$ 18,266	$ 15,729	$ 6,203	$ 4,651	$ 12,071	$ 18,155	$ 36,895	$ 13,674	$ (11,505)

Exhibit GKW-R-1
Page 77 of 121

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Account 4081-Taxes Other than Income Tax by Sub-Account
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:________Base Period__X____Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).

FR 16(8)(c)2.3
Schedule C-2.3 F
Witness: Waller

Line No.	Discription	Forecasted Apr-19	Forecasted May-19	Forecasted Jun-19	Forecasted Jul-19	Forecasted Aug-19	Forecasted Sep-19	Forecasted Oct-19	Forecasted Nov-19	Forecasted Dec-19	Forecasted Jan-20	Forecasted Feb-20	Forecasted Mar-20	Total
	Div 009													
1														
2														
3	Payroll	19,472	23,062	20,042	22,493	13,986	49,875	18,239	64,282	10,577	45,026	22,712	46,194	355,960
4	Payroll Tax Projects	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Ad Valorem - Accrual	492,510	492,510	492,510	492,510	492,510	492,510	492,510	492,510	492,510	492,510	492,510	492,510	5,910,122
6	Dot Transmission User Tax	-	137,062	-	-	-	-	-	-	-	-	-	-	137,062
7	Taxes Property and Other	45,644	43	-	16,431	211	83	11,110	66	338	22,305	-	2,869	99,099
8	Public Service Commission Assessment	28,286	28,286	28,286	28,286	28,286	28,286	28,286	28,286	28,286	28,286	28,286	28,286	339,436
9	Allocation for taxes other CSC	15,512	15,512	15,512	15,512	15,512	15,512	15,888	15,888	15,888	15,888	15,888	15,888	188,397
10	Allocation from taxes other SS	23,138	23,138	23,138	23,138	23,138	23,138	23,688	23,688	23,688	23,688	23,688	23,688	280,956
11	Allocation from taxes other Gen Office	16,273	18,515	15,181	13,734	17,519	2,397	18,688	37,990	14,073	19,617	18,767	8,050	200,805
12														
13	Total	$ 640,835	$ 738,129	$ 594,669	$ 612,104	$ 591,163	$ 611,801	$ 608,409	$ 662,710	$ 585,360	$ 647,320	$ 601,852	$ 617,486	$ 7,511,837
14														
15	**Div 002**													
16														
17														
18	Payroll	$ 353,794	$ 353,794	$ 353,794	$ 353,794	$ 353,794	$ 353,794	$ 364,408	$ 364,408	$ 364,408	$ 364,408	$ 364,408	$ 364,408	4,309,211
19	Ad Valorem	$ 93,139	$ 93,139	$ 93,139	$ 93,139	$ 93,139	$ 93,139	$ 93,139	$ 93,139	$ 93,139	$ 93,139	$ 93,139	$ 93,139	1,117,668
20	Benefit Load Projects	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Taxes Property And Other	-	-	-	-	-	-	-	-	-	-	-	-	-
22														
23	Total Tax Other Than Income Tax	$ 446,933	$ 446,933	$ 446,933	$ 446,933	$ 446,933	$ 446,933	$ 457,547	$ 457,547	$ 457,547	$ 457,547	$ 457,547	$ 457,547	$ 5,426,879
24														
25	Allocation Factor to Kentucky Mid-States (Div 091)	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%	
26	Allocation Factor to Kentucky Jurisdiction (Div 009)	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	
27														
28	Total Allocated Amount from Div 2	23,138	23,138	23,138	23,138	23,138	23,138	23,688	23,688	23,688	23,688	23,688	23,688	$ 280,956
29														
30	**Div 012**													
31														
32														
33	Payroll	$ 222,369	$ 222,369	$ 222,369	$ 222,369	$ 222,369	$ 222,369	$ 229,040	$ 229,040	$ 229,040	$ 229,040	$ 229,040	$ 229,040	2,708,452
34	Ad Valorem	$ 52,600	52,600	52,600	52,600	52,600	52,600	52,600	52,600	52,600	52,600	52,600	52,600	631,200
35														
36	Total Tax Other Than Income Tax	$ 274,969	$ 274,969	$ 274,969	$ 274,969	$ 274,969	$ 274,969	$ 281,640	$ 281,640	$ 281,640	$ 281,640	$ 281,640	$ 281,640	$ 3,339,652
37														
38	Allocation Factor to Kentucky Mid-States (Div 091)	10.95%	10.95%	10.95%	10.95%	10.95%	10.95%	10.95%	10.95%	10.95%	10.95%	10.95%	10.95%	
39	Allocation Factor to Kentucky Jurisdiction (Div 009)	51.52%	51.52%	51.52%	51.52%	51.52%	51.52%	51.52%	51.52%	51.52%	51.52%	51.52%	51.52%	
40														
41	Total Allocated Amount from Div 12	15,512	15,512	15,512	15,512	15,512	15,512	15,888	15,888	15,888	15,888	15,888	15,888	$ 188,397
42														
43	**Div 091**													
44														
45														
46	Payroll	$ 31,891	$ 36,394	$ 29,696	$ 26,789	$ 34,394	$ 4,015	$ 36,741	$ 75,516	$ 27,470	$ 38,608	$ 36,879	$ 15,328	$ 393,719
47	Payroll Tax Projects	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22	$ 44	66
48	Ad Valorem	800	800	800	800	800	800	800	800	800	800	800	800	9,600
49	Occupational Licenses	-	-	-	-	-	-	-	-	-	-	-	-	-
50														
51	Total Tax Other Than Income Tax	$ 32,691	$ 37,194	$ 30,496	$ 27,589	$ 35,194	$ 4,815	$ 37,541	$ 76,316	$ 28,270	$ 39,408	$ 37,701	$ 16,172	$ 403,385
52														
53	Allocation Factor to Kentucky Mid-States (Div 091)	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
54	Allocation Factor to Kentucky Jurisdiction (Div 009)	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	49.78%	
55														
56	Total Allocated Amount from Div 91	16,273	18,515	15,181	13,734	17,519	2,397	18,688	37,990	14,073	19,617	18,767	8,050	$ 200,805

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

FR 16(8)(d) SCHEDULE D

Operating Income Summary

Schedule	Pages	Description
D-1	4	Summary of Utility Jurisdictional Adjustments to Operating Income by Account
D-2.1	1	Detailed Adjustments
D-2.2	1	Detailed Adjustments
D-2.3	1	Detailed Adjustments

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Summary of Utility Jurisdictional Adjustments to
Operating Income by Major Accounts
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:__X___Base Period__X___Forecasted Period
Type of Filing:______Original______Updated___X___Revised
Workpaper Reference No(s).

FR 16(8)(d)1
Schedule D-1
Witness: Waller, Densman

Line No.	Account No. & Title	Base Period	Title of Adjustment D-2.1 ADJ 1	D-2.1 ADJ 2	D-2.1 ADJ 3	D-2.2 ADJ 4	D-2.2 ADJ 5	Total ADJUST.
	SALE of Gas							
1	480 Gas Rev - Residential	106,055,302	(9,535,811)					(9,535,811)
2	480 Gas Rev - Commericial	45,531,133	(3,923,113)					(3,923,113)
3	480 Gas Rev - Industrial	6,051,221	(680,837)					(680,837)
4	480 Gas Rev - Public Authority & Other	7,513,898	(764,092)					(764,092)
5								
6								
7	Total SALE of Gas	165,151,555	(14,903,853)	0	0	0	0	(14,903,853)
8								
9	Other Operating Income							
10	Forfeited discounts	1,388,389		(83,424)				(83,424)
11	488 MISC. Service Revenues	792,006		14,048				14,048
12	489 Revenue From Transporting Gas to Others	17,013,346		(2,131,964)				(2,131,964)
13	495 Other Gas Service Revenue	1,148,568		1,329,195				1,329,195
14								
15	Total Other Operating Income	20,342,309	0	(872,145)	0	0	0	(872,145)
16								
17	Total Operating Revenue	185,493,864	(14,903,853)	(872,145)	0	0	0	(15,775,998)
18								
19	Other Gas Supply Expenses - Operation							
20	803/804/812 Gas Purchase Costs	83,882,422			(5,500,067)			(5,500,067)
21								
22	Total Other Gas Supply Expenses - Operation	83,882,422	0	0	(5,500,067)	0	0	(5,500,067)
23								
24	Total Plant Revenue	101,611,442	(14,903,853)	(872,145)	5,500,067	0	0	(10,275,930)
25								
26	Blended Effective Tax Rate	24.95%	(3,718,511)	(217,600)	1,372,267	0	0	(2,563,845)
27								
28	NET Operating Income Impact		(11,185,341)	(654,545)	4,127,801	0	0	(7,712,086)

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Summary of Utility Jurisdictional Adjustments to
Operating Income by Major Accounts
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:__X____Base Period__X____Forecasted Period
Type of Filing:_______Original_______Updated ____X____Revised
Workpaper Reference No(s).

FR 16(8)(d)1
Schedule D-1
Witness: Waller, Densman

Line No.	ACCOUNT No. & Title		Base Period	Title of Adjustment D-2.2 ADJ 1	D-2.2 ADJ 2	D-2.2 ADJ 3	D-2.2 ADJ 4	D-2.2 ADJ 5	GRAND Total ADJUST.
29	7590	814 Storage Supervision & Engineering	-	-	-	-	-	-	-
30	8140	814 Storage Supervision & Engineering	-	-	-	-	-		-
31	8150	815 Maps and records	-	-	-	-	-	-	-
32	8160	816 Storage Wells Expense	326,734	(1,090)	-	-	-	-	(1,090)
33	8170	817 Storage Lines Expense	22,639	(648)	(297)	(297)	-	-	(1,241)
34	8180	818 Storage Compressor Station	28,860	(523)	(22)	(22)	-	-	(566)
35	8190	819 Storage Compressor Station Fuel	879	-	(143)	(143)	-	-	(287)
36	8200	820 Storage Measuring & Regulating	6,847	(69)	(220)	(220)	-	-	(510)
37	8210	821 Storage Purification	54,469	(1,370)	(335)	(335)	-	-	(2,040)
38	8240	824 Storage Other Expense	-	-	-	-	-	-	-
39	8250	825 Storage Royalties	10,451	-	(1,706)	(1,706)	-	-	(3,412)
40	8310	831 Storage Maintenance Structure	13,541	-	-	-	-	-	-
41	8320	832 Storage Maintenance Res	-	-	-	-	-	-	-
42	8340	834 Storage Maintenance Compressor	3,463	(115)	-	-	-	-	(115)
43	8350	835 Storage Maintenance Meas/Reg	-	-	-	-	-	-	-
44	8360	836 Storage Maintenance Purification	-	-	-	-	-	-	-
45	8370	837 Maintenance of other equipment	-	-	-	-	-		-
46	8400	840 Other Storage Expense	-	-	-	-	-	-	-
47	8410	841 Storage Operation	71,800	(2,227)	-	-	-	-	(2,227)
48	8470	847 Storage Maintenance	-	-	-	-	-	-	-
49	8500	850 Trsm Supervision & Engineering	47	-	-	-	-	-	-
50	8520	852 Communication system expenses	-	-	-	-	-		-
51	8550	855 Other Fuel & Power Comp	368	-	(60)	(60)			
52	8560	856 Trsm Mains Expense	395,189	(6,907)	(1,863)	(1,863)	-	-	(10,633)
53	8570	857 Trsm Measuring & Regulating	29,427	(724)	(1,145)	(1,145)	-	-	(3,014)
54	8590	859 Trsm Other Exp	-	-	-	-	-	-	-
55	8600	860 Rents	-	-	-	-	-	-	-
56	8620	862 Trsm Structure & Improvements	-	-	-	-	-	-	-
57	8630	863 Trsm Maint of Mains	16,570	(534)	-	-	-	-	(534)
58	8640	864 Trsm Maint Comp Sta Equip	-	-	-	-	-	-	-
59	8650	865 Trsm Maint Meas/Reg Sta	-	-	-	-	-	-	-
60	8670	867 Trsm Maint Other Eq	-	-	-	-	-	-	-
61	8700	870 Dist Supervision & Engineering	1,452,843	(14,403)	(8,545)	(8,545)	-	-	(31,493)
62	8710	871 Dist Load Dispatching	792	-	(129)	(129)	-	-	(259)
63	8711	8711 Odorization	26,727	-	-	-	-	-	-
64	8720	872 Dist Comp Sta	-	-	-	-	-	-	-
65	8740	874 Dist Main/Ser Exp	4,585,210	(58,399)	(9,104)	(9,104)	-	-	(76,608)
66	8750	875 Dist Meas/Reg Sta-Gen	618,262	(14,798)	(204)	(204)	-	-	(15,206)
67	8760	876 Dist Meas/Reg Sta-Ind	125,801	(4,134)	-	-	-	-	(4,134)
68	8770	877 Dist Meas/Reg Sta-Cty.	45,140	-	(679)	(679)	-	-	(1,357)
69	8780	878 Dist Mtr/House Reg	848,813	(26,085)	(2,205)	(2,205)	-	-	(30,496)
70	8790	879 Dist Cust Install	3,009	-	-	-	-	-	-
71	8800	880 Dist Other Exp	5,729	2	-	-	-	-	2
72	8810	881 Dist Rents	443,578	-	(72,071)	(72,071)	-	-	(144,142)
73	8850	885 Dist Maint Super/Eng	1,232	-	-	-	-	-	-
74	8860	886 Dist Maint Struc/Improv	131	-	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Summary of Utility Jurisdictional Adjustments to
Operating Income by Major Accounts
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:__X___Base Period__X___Forecasted Period
Type of Filing:______Original_______Updated ___X___Revised
Workpaper Reference No(s).

FR 16(8)(d)1
Schedule D-1
Witness: Waller, Densman

Line No.	Account No. & Title		Base Period	Title of Adjustment D-2.2 ADJ 1	D-2.2 ADJ 2	D-2.2 ADJ 3	D-2.2 ADJ 4	D-2.2 ADJ 5	GRAND Total ADJUST.
75	8870	887 Dist Maint of Mains	30,074	(783)	(5)	(5)	-	-	(793)
76	8890	889 Dist Maint Meas/Reg Sta-Gen	71,786	(1,747)	(1,204)	(1,204)	-	-	(4,154)
77	8900	890 Dist Maint Meas/Reg Sta-Ind	2,114	(22)	-	-	-	-	(22)
78	8910	891 Dist Maint Meas/Reg Sta-Cty	950	-	(155)	(155)	-	-	(310)
79	8920	892 Dist Maint of Ser	6,794	(226)	-	-	-	-	(226)
80	8930	893 Dist Maint Mtr/House Reg	-	-	-	-	-	-	-
81	8940	894 Dist Maint Other Eq	7,847	-	-	-	-	-	-
82	8950	895 Maintenance of Other Plant	-	-	-	-	-	-	-
83	9010	901 Cust Accts Supervision	-	-	-	-	-	-	-
84	9020	902 Cust Accts Mtr Exp	1,127,896	(15,948)	(701)	(701)	-	-	(17,350)
85	9030	903 Cust Accts Records/Collections	1,283,457	(14,682)	(30)	(30)	-	-	(14,742)
86	9040	904 Cust Accts Uncoll Accts	549,343	-	-	-	(208,293)	-	(208,293)
87	9070	907 Cust Accts Supervision	-	-	-	-	-	-	-
88	9080	908 Customer Assistance Expenses	-	-	-	-	-	-	-
89	9090	909 Cust Ser Supervision	129,523	(3,583)	-	-	-	-	(3,583)
90	9100	910 Cust Ser Assist Exp	-	-	-	-	-	-	-
91	9110	911 Cust Ser Info Adv Exp	253,382	(6,378)	-	-	-	-	(6,378)
92	9120	912 Demonstrating and Selling Expenses	143,981	-	-	-	-	-	-
93	9130	913 Advertising Expenses	43,530	-	-	-	-	-	-
94	9160	916 Sales Promo Demo/Selling	-	-	-	-	-	-	-
95	9200	920 Administrative and General Salaries	132,956	(4,516)	-	-	-	-	(4,516)
96	9210	921 Adm Gen Office Supply	19,311	-	-	-	-	-	-
97	9220	922 Administrative Expense Transferred	13,030,745	-	-	-	-	1,468,019	1,468,019
98	9230	923 Adm Gen Outside Services Emply	359,911	-	-	-	-	-	-
99	9240	924 Property insurance	88,358	-	-	-	-	-	-
100	9250	925 Adm Gen Injuries/Damages	79,906	-	-	-	-	-	-
101	9260	926 Adm Gen Empl Pen/Ben	1,821,264	(16,969)	-	-	-	-	(16,969)
102	9270	927 Adm Gen Franchise Req	800	-	-	-	-	-	-
103	9280	928 Adm Gen Reg Comm Exp	92,766	-	-	-	-	-	-
104	9290	929 Uniforms capitalized	-	-	-	-	-	-	-
105	9301	9301 Adm Gen Goodwill Adv	-	-	-	-	-	-	-
106	9302	9302 Adm Gen Gen Exp	83,791	-	-	-	-	-	-
107	9310	931 A&G-Rents	13,266	-	(2,166)	(2,166)	-		(4,332)
108	9320	932 Adm Gen Maint Gen Plant	18,812	-	-	-	-	-	-
109	Total		28,531,137	(196,878)	(102,990)	(102,990)	(208,293)	1,468,019	856,988
110	Labor and Benefits		7,010,809	(196,878)					(196,878)
111	Rent, Maintenance and Utilites		630,787		(102,990)				(102,990)
112	Other O&M		15,500,391			(102,990)			(102,990)
113	Bad Debt		549,343				(208,293)		(208,293)
114	Costs allocated from SSU and KY-MDS General Office		13,030,745	0	(0)	(372,871)		1,468,019	1,095,148
115	Total		36,722,076	(196,878)	(102,990)	(475,861)	(208,293)	1,468,018	483,997
116	Blended Effective Tax Rate		24.95%	49,121	25,696	118,727	51,969	(366,271)	(120,757)
117	NET Operating Income Impact			(147,757)	(77,294)	(357,134)	(156,324)	1,101,748	363,239

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Summary of Utility Jurisdictional Adjustments to
Operating Income by Major Accounts
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:__X___Base Period__X___Forecasted Period
Type of Filing:______Original______Updated ___X___Revised
Workpaper Reference No(s).

FR 16(8)(d)1
Schedule D-1
Witness: Waller, Densman

			Title of Adjustment					
Line No.	Account No. & Title	Base Period	D-2.3 ADJ 1	D-2.3 ADJ 2	D-2.1 ADJ 3	D-2.2 ADJ 4	D-2.2 ADJ 5	Total ADJUST.
118	403 DEPRECIATION Expense	20,643,162	2,458,934					2,458,934
119	404 Amortization Expense	0						0
120	406 AMORT. - Gas Plant AQUIST.	24,559						0
121								
122	Total DEPRECIATION and Amortization	20,667,720	2,458,934					2,458,934
123								
124	Blended Effective Tax Rate	24.95%	613,504					613,504
125								
126	NET Operating Income Impact		1,845,430					1,845,430
127								
128								
129								
130								
131	408 Taxes, Other than Income	6,491,574		1,020,263				1,020,263
132								
133	Blended Effective Tax Rate	24.95%		254,556				254,556
134								
135	NET Operating Income Impact			765,708				765,708

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Detailed Adjustments
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:__X_____Base Period___X____Forecasted Period — FR 16(8)(d)2.1
Type of Filing:___X_____Original________Updated — Schedule D-2.1
Workpaper Reference No(s).________________ — Witness: Waller, Densman

LN NO	Purpose and Description		Amount
1	**ADJ1**		
2	SALE of Gas-Residential - the purpose of this Adjustment is to reflect the normalization of volumes	Forecasted	$96,519,490
3	due to cold weather in base period, and changes in gas costs between the periods	Base	106,055,302
4		Adjustment	($9,535,811)
5			-9.0%
6			
7	SALE of Gas-Commercial - the purpose of this Adjustment is to reflect the normalization of volumes	Forecasted	$41,608,020
8	due to cold weather in base period, and changes in gas costs between the periods	Base	45,531,133
9		Adjustment	($3,923,113)
10			-8.6%
11			
12	SALE of Gas-Industrial - the purpose of this Adjustment is to reflect known and measurable changes,	Forecasted	$5,370,385
13	increases and reductions, shifts from base period to test year and	Base	6,051,221
14	changes in gas costs between the periods.	Adjustment	($680,837)
15			-11.3%
16			
17	SALE of Gas-Public Authority - The purpose of this Adjustment is to reflect the normalization of	Forecasted	$6,749,807
18	volumes due to cold weather in base period, and changes in gas costs between the periods	Base	7,513,898
19		Adjustment	($764,092)
20			-10.2%
21			
22	SALE of Gas - Unbilled - no adjustment.	Forecasted	$0
23		Base	0
24		Adjustment	$0
25			0.0%
26	**ADJ2**		
27	Forfeited discounts - the purpose of this adjustment is to reflect anticipated changes in the billed late	Forecasted	$1,304,965
28	payment fees from the base period to the test year.	Base	1,388,389
29		Adjustment	($83,424)
30			-6.0%
31			
32	Misc Service Revenues - the purpose of this adjustment is to reflect modest reduction in service charge	Forecasted	$806,054
33	revenues for the base period.	Base	792,006
34		Adjustment	$14,048
35			1.8%
36			
37	Revenue from Transportation - the purpose of this Adjustment is to reflect known and measurable	Forecasted	$14,881,382
38	changes in demand for existing industries and account for migration to/from transportation service	Base	17,013,346
39		Adjustment	($2,131,964)
40			-12.5%
41			
42	Other gas service revenues - the purpose of this adjustment is to reflect pro forma adjustments for	Forecasted	$2,477,763
43	individual customers and special contract reformations	Base	1,148,568
44		Adjustment	$1,329,195
45			115.7%
46	**ADJ3**		
47	Gas Purchase Costs - The purpose of this Adjustment is to reflect the purchase quantities	Forecasted	$78,382,354
48	for sales service. The Base Period includes Unbilled Gas Costs that will zero out by the end	Base	83,882,422
49	of the base period when replaced by actuals. Gas costs in the Forecasted Period are lower	Adjustment	($5,500,067)
50	primarily due to lower estimated GCA price		-6.6%
51			
52			
53			
54	Summary of Revenue Adjustments.		
55	Base Year Revenues		185,493,864
56	Base Year Gas Costs		83,882,422
57	Base Year Gross Profit		101,611,442
58			
59	Test Year Revenues		169,717,866
60	Test Year Gas costs		78,382,354
61	Test Year Gross Profit		91,335,512

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Detailed Adjustments
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:___X____Base Period___X____Forecasted Period
Type of Filing:___X_____Original________Updated
Workpaper Reference No(s).__________

FR 16(8)(d)2.2
Schedule D-2.2
Witness: Waller, Densman

LN NO	Purpose and Description		Amount
1	**ADJ 1**		
2	Labor and Benefits - The purpose of this adjustment is to account for forecasted labor and benefits expense	Forecasted	6,813,931
3	due primarily to adjustments to labor capitalization rate versus the base period.	Base	7,010,809
4	Benefits are projected as a fixed benefit load percentage of labor expense plus an amount for workers' comp	Adjustment	(196,878)
5	insurance. This adjustment pertains to labor and benefits for Kentucky operations.		-2.8%
6			
7	**ADJ 2**		
8	Rent, Maintenance and Utilities - The purpose of this adjustment is to account for forecasted rent, maintenance	Forecasted	527,796
9	and utilities. Unlike other O&M categories that are likely to increase with normal inflation, our building rents are	Base	630,787
10	driven by leases already in place and can therefore be projected with a high level of accuracy. The rent portion	Adjustment	($102,990)
11	of this O&M category was projected by reviewing actual lease amounts. This adjustment pertains to expenses		-16.3%
12	for Kentucky operations.		
13			
14	**ADJ 3**		
15	Other O&M - The purpose of this adjustment is to account for projected changes in O&M expenses other than	Forecasted	6,833,591
16	labor, benefits, rent, and bad debt.	Base	7,309,452
17	This adjustment pertains to expenses for Kentucky operations.	Adjustment	($475,861)
18			-6.5%
19			
20	**ADJ 4**		
21	Bad Debt - The purpose of this adjustment is to account for anticipated bad debt costs due to uncollectible	Forecasted	341,050
22	accounts. The projection is made by calculating 0.50% of residential, commercial and public authority	Base	549,343
23	margins from the revenues projection.	Adjustment	($208,293)
24			-61.1%
25	**ADJ 5**		
26	Costs allocated from Shared Services and Kentucky-Mid States General Office - The purpose of this	Forecasted	14,498,764
27	adjustment is to account for the forecasted amount of expenses that are allocated to Kentucky from the	Base	13,030,746
28	Shared Services Unit and Division General Office.	Adjustment	$1,468,018
29			11.3%
30			
31	Summary of O & M adjustments.	Forecasted	29,015,133
32		Base	28,531,137
33		Adjustment	$483,996
34			1.7%

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Detailed Adjustments
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:___X____Base Period___X____Forecasted Period — FR 16(8)(d)2.3
Type of Filing:___X____Original________Updated ________Revised — Schedule D-2.3
Workpaper Reference No(s).________________ — Witness: Waller, Densman

LN NO	Purpose and Description		Amount
1	**ADJ1**		
2	Depreciation Expense - The purpose of this adjustment is to reflect the change in	Forecasted	$23,102,096
3	depreciation expense due to the increased level of depreciable plant investment.	Base	20,643,162
4		Adjustment	$2,458,934
5			11.9%
6	**ADJ2**		
7	Taxes Other - The purpose of this adjustment is to account for anticipated	Forecasted	$7,511,837
8	changes in Taxes, Other than Income Taxes	Base	6,491,574
9		Adjustment	$1,020,263
10			15.7%

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

FR 16(8)(e) SCHEDULE E

Income Tax Calculation

Schedule	Pages	Description
E	1	Income Tax Calculation

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Computation of State & Federal Income Tax
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

FR 16(8)(e)
Type of Filing:___X____Original________Updated ________Revised — Schedule E
Workpaper Reference No(s).__________________ — Witness: Waller, Story

Line No.	Description	Base Period Unadjusted (1)	Adjustments (2)	Test Period Fully Adjusted (3)	Sched. Ref.
1	Operating Income before Income Tax & Interest	$ 33,822,603	$ (259,977)	$ 33,562,626	C-2
2	Interest Deduction	8,488,094	894,788	9,382,883	*
3	Taxable Income	$ 25,334,509	$ (1,154,766)	$ 24,179,744	
4	Composite Tax Rate (state & federal)	24.950%		24.950%	* *
5	**State & Federal Income Tax**	$ 6,320,960	$ (288,114)	**$ 6,032,846**	
	* Interest Expense Calculation:				
6	13 Month Average Rate Base	$414,053,383		$496,005,827	B-1
7	Weighted cost of Debt	2.05%		1.89%	J-1
8	Interest Expense	$ 8,488,094		$ 9,382,883	
9	2018 * * Composite Tax Rate Calculation: 5.00% + 21%(100% - 6.00%) = 24.95%				
10	State Tax Rate	5.00%			
11	Federal Tax Rate	21.00%			

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

FR 16(8)(f) SCHEDULE F

Schedule	Pages	Description
F-1	2	Social and Service Club Dues
F-2.1	1	Charitable Contributions
F-2.2	1	Initiation Fees/Country Club Expenses
F-2.3	1	Employee Party, Outing and Gift Expenses
F-3	1	Sales and Advertising Expenses
F-4	1	Advertising
F-5	1	Professional Service Expenses
F-6	1	Projected Rate Case Expense
F-7	1	Civic, Political and Related Activities
F-8	1	Expense Reports
F-9	1	Leases
F-10	1	Incentive Compensation Expense

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
SOCIAL and Service CLUB DUES
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:___X___Base Period___X____Forecasted Period — FR 16(8)(f)
Type of Filing:___X____Original________Updated________Revised — Schedule F-1
Workpaper Reference No(s). — Witness: Waller

Line No.	Account No	Social Organization/Service Club	Total Utility	Jurisdictional %	Jurisdiction
		BASE PERIOD			
1	Various	AGA	44,365	100%	44,365
2	Various	MCLEAN COUNTY CHAMBER OF COMMERCE	100		100
3	Various	LAKE BARKLEY CHAMBER OF COMMERCE	140		140
4	Various	LEADERSHIP KENTUCKY FOUNDATION INC.	100		100
5	Various	LAKE NEWS	27		27
6	Various	NACE INTERNATIONAL	130		130
7	Various	PENNYRILE BOARD OF REALTORS	75		75
8	Various	KENTUCKY COUNTY JUDGE EXECUTIVE ASSOCIATION	200		200
9	Various	CAMPBELLSVILLE / TAYLOR COUNTY CHAMBER OF COMMERCE	59		59
10	Various	PRINCETON / CALDWELL COUNTY CHAMBER OF COMMERCE	510		510
11	Various	GLASGOW/BARREN COUNTY CHAMBER OF COMMERCE	2,500		2,500
12	Various	GLASGOW/BARREN COUNTY CHAMBER OF COMMERCE	1,250		1,250
13	Various	GLASGOW/BARREN COUNTY CHAMBER OF COMMERCE	75		75
14	Various	CAVE CITY CHAMBER OF COMMERCE	200		200
15	Various	HOPKINSVILLE CHRISTIAN AND TODD COUNTY ASSN OF REALT(	150		150
16	Various	HOME BUILDERS ASSOCIATION OF OWENSBORO	300		300
17	Various	TRIGG COUNTY CHAMBER OF COMMERCE	235		235
18	Various	KENTUCKY GAS ASSOCIATION	250		250
19	Various	BUILDING INDUSTRY ASSOCIATION OF GREATER LOUISVILLE	421		421
20	Various	OHIO COUNTY CHAMBER OF COMMERCE	300		300
21	Various	PADUCAH AREA CHAMBER OF COMMERCE	350		350
22	Various	GREATER OWENSBORO ECONOMIC DEVELOPMENT CORP	10,000		10,000
23	Various	KENTUCKY CHAMBER OF COMMERCE	13,735		13,735
24	Various	MARION COUNTY CHAMBER OF COMMERCE	400		400
25	Various	GREATER BRECKINRIDGE COUNTY CHAMBER OF COMMERCE	150		150
26	Various	GREATER OWENSBORO CHAMBER OF COMMERCE	760		760
27	Various	HOPKINS COUNTY HOME BUILDERS ASSOCIATION	295		295
28	Various	ANDERSON COUNTY CHAMBER OF COMMERCE	300		300
29	Various	ANDERSON COUNTY CHAMBER OF COMMERCE	3,000		3,000
30	Various	GREENSBURG / GREEN COUNTY CHAMBER OF COMMERCE	200		200
31	Various	MAYFIELD /GRAVES COUNTY CHAMBER OF COMMERCE	775		775
32	Various	KENTUCKY ASSOCIATION OF MASTER CONTRACTORS INC	2,500		2,500
33	Various	GREATER MUHLENBERG CHAMBER OF COMMERCE	187		187
34	Various	SHELBY COUNTY CHAMBER OF COMMERCE	2,999		2,999
35	Various	ECONOMIC DEVELOPMENT COUNCIL	11,000		11,000
36	Various	CHRISTIAN COUNTY CHAMBER OF COMMERCE	1,348		1,348
37	Various	MAD HOP CO BOARD OF REALTORS	100		100
38	Various	KENTUCKY RESTAURANT ASSOCIATION	395		395
39	Various	BOWLING GREEN AREA CHAMBER OF COMMERCE	7,500		7,500
40	Various	HOPKINS COUNTY REGIONAL CHAMBER OF COMMERCE	305		305
41	Various	REALTOR ASSOCIATION OF SOUTHERN KENTUCKY	200		200
42	Various	HOME BUILDERS ASSOCIATION	415		415
43	Various	DANVILLE BOYLE COUNTY CHAMBER OF COMMERCE	421		421
44	Various	GREATER OWENSBORO REALTOR ASSOCIATION	256		256
45	Various	KENTUCKY LAKE CHAMBER OF COMMERCE	500		500
46	Various	GRAND RIVERS CHAMBER OF COMMERCE	100		100
47	Various	CADIZ ROTARY CLUB	100		100
48	Various	DAWSON SPRINGS CHAMBER OF COMMERCE	75		75
49	Various	HOME BUILDERS ASSOCIATION	450		450
50	Various	OWENSBORO ASSN OF PLUMBING HEATING AND COOLING CON	100		100
51	Various	FRANKLIN-SIMPSON CHAMBER OF COMMERCE	1,000		1,000
52	Various	PADUCAH BOARD OF REALTORS INC	300		300
53	Various	AMERICAN SOCIETY OF MECHANICAL ENGINEERS	155		155
54	Various	OKLAHOMA ACCOUNTANCY BOARD	34		34
55	Various	TENNESSEE PROFESSIONAL ENGINEER (LICENSE RENEWAL)	140		140
56	Various	SAM'S CLUB	50		50
57	Various	KENTUCKY STATE TREASURER (NOTARY RENEWAL)	50		50
58	Various	SAM'S CLUB	20		20
59	Various	CITY OF STANFORD, KY (BUSINESS LICENSE)	70		70
60	Various	WARREN COUNTY CLERKS OFFICE	38		38
61	Various	NATIONAL SOCIETY OF PROFESSIONAL ENGINEERS	264		264
62	Various	TNTAP	409		409
63	Various	KENTUCKY OIL AND GAS ASSOCIATION	1,000		1,000
64	Various	LOGAN COUNTY HOME BUILDERS	350		350
65	Various	LINCOLN COUNTY CHAMBER OF COMMERCE	140		140
66	Various	SOCIETY FOR MARKETING PROFESSIONAL SERVICES	420		420
67	Various	CRITTENDEN COUNTY ECONOMIC DEVELOPMENT	250		250
68	Various	CRITTENDEN COUNTY ECONOMIC DEVELOPMENT	250		250
69	Various	GARRARD COUNTY CHAMBER OF COMMERCE	300		300
70	Various	HART COUNTY CHAMBER OF COMMERCE	200		200
71	Various	SOUTH WESTERN KENTUCKY ECONOMIC DEVELOPMENT COUN	11,000		11,000
		Total Base Period	126,745		126,745

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
SOCIAL and Service CLUB DUES
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:___X___Base Period___X____Forecasted Period — FR 16(8)(f)
Type of Filing:___X____Original________Updated________Revised — Schedule F-1
Workpaper Reference No(s). — Witness: Waller

Line No.	Account No	Social Organization/Service Club	Total Utility	Jurisdictional %	Jurisdiction
		TEST PERIOD			
1	Various	AGA	44,365	100%	44,365
2	Various	MCLEAN COUNTY CHAMBER OF COMMERCE	100		100
3	Various	LAKE BARKLEY CHAMBER OF COMMERCE	140		140
4	Various	LEADERSHIP KENTUCKY FOUNDATION INC.	100		100
5	Various	LAKE NEWS	27		27
6	Various	NACE INTERNATIONAL	130		130
7	Various	PENNYRILE BOARD OF REALTORS	75		75
8	Various	KENTUCKY COUNTY JUDGE EXECUTIVE ASSOCIATION	200		200
9	Various	CAMPBELLSVILLE / TAYLOR COUNTY CHAMBER OF COMMERCE	59		59
10	Various	PRINCETON / CALDWELL COUNTY CHAMBER OF COMMERCE	510		510
11	Various	GLASGOW/BARREN COUNTY CHAMBER OF COMMERCE	2,500		2,500
12	Various	GLASGOW/BARREN COUNTY CHAMBER OF COMMERCE	1,250		1,250
13	Various	GLASGOW/BARREN COUNTY CHAMBER OF COMMERCE	75		75
14	Various	CAVE CITY CHAMBER OF COMMERCE	200		200
15	Various	HOPKINSVILLE CHRISTIAN AND TODD COUNTY ASSN OF REALT(	150		150
16	Various	HOME BUILDERS ASSOCIATION OF OWENSBORO	300		300
17	Various	TRIGG COUNTY CHAMBER OF COMMERCE	235		235
18	Various	KENTUCKY GAS ASSOCIATION	250		250
19	Various	BUILDING INDUSTRY ASSOCIATION OF GREATER LOUISVILLE	421		421
20	Various	OHIO COUNTY CHAMBER OF COMMERCE	300		300
21	Various	PADUCAH AREA CHAMBER OF COMMERCE	350		350
22	Various	GREATER OWENSBORO ECONOMIC DEVELOPMENT CORP	10,000		10,000
23	Various	KENTUCKY CHAMBER OF COMMERCE	13,735		13,735
24	Various	MARION COUNTY CHAMBER OF COMMERCE	400		400
25	Various	GREATER BRECKINRIDGE COUNTY CHAMBER OF COMMERCE	150		150
26	Various	GREATER OWENSBORO CHAMBER OF COMMERCE	760		760
27	Various	HOPKINS COUNTY HOME BUILDERS ASSOCIATION	295		295
28	Various	ANDERSON COUNTY CHAMBER OF COMMERCE	300		300
29	Various	ANDERSON COUNTY CHAMBER OF COMMERCE	3,000		3,000
30	Various	GREENSBURG / GREEN COUNTY CHAMBER OF COMMERCE	200		200
31	Various	MAYFIELD /GRAVES COUNTY CHAMBER OF COMMERCE	775		775
32	Various	KENTUCKY ASSOCIATION OF MASTER CONTRACTORS INC	2,500		2,500
33	Various	GREATER MUHLENBERG CHAMBER OF COMMERCE	187		187
34	Various	SHELBY COUNTY CHAMBER OF COMMERCE	2,999		2,999
35	Various	ECONOMIC DEVELOPMENT COUNCIL	11,000		11,000
36	Various	CHRISTIAN COUNTY CHAMBER OF COMMERCE	1,348		1,348
37	Various	MAD HOP CO BOARD OF REALTORS	100		100
38	Various	KENTUCKY RESTAURANT ASSOCIATION	395		395
39	Various	BOWLING GREEN AREA CHAMBER OF COMMERCE	7,500		7,500
40	Various	HOPKINS COUNTY REGIONAL CHAMBER OF COMMERCE	305		305
41	Various	REALTOR ASSOCIATION OF SOUTHERN KENTUCKY	200		200
42	Various	HOME BUILDERS ASSOCIATION	415		415
43	Various	DANVILLE BOYLE COUNTY CHAMBER OF COMMERCE	421		421
44	Various	GREATER OWENSBORO REALTOR ASSOCIATION	256		256
45	Various	KENTUCKY LAKE CHAMBER OF COMMERCE	500		500
46	Various	GRAND RIVERS CHAMBER OF COMMERCE	100		100
47	Various	CADIZ ROTARY CLUB	100		100
48	Various	DAWSON SPRINGS CHAMBER OF COMMERCE	75		75
49	Various	HOME BUILDERS ASSOCIATION	450		450
50	Various	OWENSBORO ASSN OF PLUMBING HEATING AND COOLING CON	100		100
51	Various	FRANKLIN-SIMPSON CHAMBER OF COMMERCE	1,000		1,000
52	Various	PADUCAH BOARD OF REALTORS INC	300		300
53	Various	AMERICAN SOCIETY OF MECHANICAL ENGINEERS	155		155
54	Various	OKLAHOMA ACCOUNTANCY BOARD	34		34
55	Various	TENNESSEE PROFESSIONAL ENGINEER (LICENSE RENEWAL)	140		140
56	Various	SAM'S CLUB	50		50
57	Various	KENTUCKY STATE TREASURER (NOTARY RENEWAL)	50		50
58	Various	SAM'S CLUB	20		20
59	Various	CITY OF STANFORD, KY (BUSINESS LICENSE)	70		70
60	Various	WARREN COUNTY CLERKS OFFICE	38		38
61	Various	NATIONAL SOCIETY OF PROFESSIONAL ENGINEERS	264		264
62	Various	TNTAP	409		409
63	Various	KENTUCKY OIL AND GAS ASSOCIATION	1,000		1,000
64	Various	LOGAN COUNTY HOME BUILDERS	350		350
65	Various	LINCOLN COUNTY CHAMBER OF COMMERCE	140		140
66	Various	SOCIETY FOR MARKETING PROFESSIONAL SERVICES	420		420
67	Various	CRITTENDEN COUNTY ECONOMIC DEVELOPMENT	250		250
68	Various	CRITTENDEN COUNTY ECONOMIC DEVELOPMENT	250		250
69	Various	GARRARD COUNTY CHAMBER OF COMMERCE	300		300
70	Various	HART COUNTY CHAMBER OF COMMERCE	200		200
71	Various	SOUTH WESTERN KENTUCKY ECONOMIC DEVELOPMENT COUN	11,000		11,000
		Total Forecasted Period	126,745		126,745

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
CHARITABLE CONTRIBUTIONS
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:___X___Base Period___X____Forecasted Period — FR 16(8)(f)
Type of Filing:___X____Original________Updated________Revised — Schedule F-2.1
Workpaper Reference No(s). — Witness: Waller

Line No.	Account No.	Charitable Organization *	Total Utility	Jurisdictional %	Jurisdiction
		BASE PERIOD			
1	Various	Education	$ 36,363	100%	$ 36,363
2	Various	United Way Agencies	$ -		0
3	Various	Health	$ -		0
4	Various	Museums & Arts	$ 17,865		17,865
5	Various	Youth Clubs & Centers	$ 6,350		6,350
6	Various	Community Welfare	$111,309		111,309
7	Various	American Red Cross	$ 5,000		5,000
8	Various	Salvation Army	$ -		0
9	Various	Heat Help Assistance Programs	$115,000		115,000
		Total	$291,887		$ 291,887
		TEST PERIOD			
1	Various	Education	$ 36,363	100%	$ 36,363
2	Various	United Way Agencies	$ -		0
3	Various	Health	$ -		0
4	Various	Museums & Arts	$ 17,865		17,865
5	Various	Youth Clubs & Centers	$ 6,350		6,350
6	Various	Community Welfare	$111,309		111,309
7	Various	American Red Cross	$ 5,000		5,000
8	Various	Salvation Army	$ -		0
9	Various	Heat Help Assistance Programs	$115,000		115,000
		Total	$291,887		$ 291,887

Note: These items are not included in O&M and therefore not part of revenue requirements.

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
INITIATION FEES/COUNTRY CLUB Expenses *
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:___x___Base Period___x___Forecasted Period — FR 16(8)(f)
Type of Filing:___X____Original________Updated________Revised — Schedule F-2.2
Workpaper Reference No(s). — Witness: Waller

			Base Period			Forecasted Period		
Line No.	Account No.	Payee Organization	Total Utility	Jurisdictional %	Jurisdiction	Total Utility	Jurisdictional %	Jurisdiction
1	Various	Owensboro Country Club (dues)	$ -	100%	$ -	$ -	100%	$ -
2	Various	OCC - Expenses	0		0	0		0
3		Total	$ -		$ -	$ -		$ -

NOTE: Country Club dues will be excluded from O & M and therefore, excluded from the revenue requirements. A/C 870.
NOTE: There are no OCC expenses for the Base Period

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Employee PARTY, OUTING, and GIFT EXP.
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:___x___Base Period___X___Forecasted Period
Type of Filing:___X____Original_______Updated_______Revised
Workpaper Reference No(s)._____________________

FR 16(8)(f)
Schedule F-2.3
Witness: Waller

			Base Period			Forecasted Period		
Line No.	Account No.	Description of Expenses	Total Utility	Kentucky Jurisdictional	Allocated Amount	Total Utility	Kentucky Jurisdictional	Allocated Amount
1		**Div 009**						
2	Various	Sub Account 07421- Service Awards	$ -	100%	$ -	$ -	100%	$ -
3								
4		Total	$ -		$ -	$ -		$ -
5								
6		**Div 091**						
7	Various	Sub Account 07421- Service Awards	$ 44,392	49.78%	$ 22,098	$ 37,359	49.78%	$ 18,598
8								
9		Total	$ 44,392		$ 22,098	$ 37,359		$ 18,598
10								
11		**Div 002**						
12	Various	Sub Account 07421- Service Awards	$ -	5.18%	$ -	$ -	5.18%	$ -
13								
14		Total	$ -		$ -	$ -		$ -
15								
16		**Div 012**						
17	Various	Sub Account 07421- Service Awards	$ 175,118	5.64%	$ 9,879	$ 300,931	5.64%	$ 16,976
18								
19		Total	$ 175,118		$ 9,879	$ 300,931		$ 16,976
20								
21		**Grand Total**	$ 219,510		$ 31,977	$ 338,291		$ 35,574

Exhibit GKW-R-1
Page 94 of 121

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Customer Service and Informational SALES and General ADVERTISING Expense
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:__x__Base Period__x__Forecasted Period — FR 16(8)(f)
Type of Filing:___X____Original________Updated_________Revised — Schedule F-3
Workpaper Reference No(s).__________________ — Witness: Waller

			Base Period			Forecasted Period		
Line No.	Account Number	Description of Expenses	Total Utility	Kentucky Jurisdictional	Allocated Amount	Total Utility	Kentucky Jurisdictional	Allocated Amount
1		**Customer Service and Informational Expenses**						
2								
3		**Div 009**						
4	907	Supervision (1)	$ -	100%	$ -	$ -	100%	$ -
5	908	Customer Assistance	-	100%	-	-	100%	-
6	909	Informational Advertising (1)	129,523	100%	129,523	128,272	100%	128,272
7	910	Miscellaneous Customer Service and Informational (1)	-	100%	-	-	100%	-
8		Total	$ 129,523		$ 129,523	$ 128,272		$ 128,272
9								
10		**Div 091**						
11	907	Supervision (1)	$ -	49.78%	$ -	$ -	49.78%	$ -
12	908	Customer Assistance	-	49.78%	-	-	49.78%	-
13	909	Informational Advertising (1)	-	49.78%	-	-	49.78%	-
14	910	Miscellaneous Customer Service and Informational (1)	1,363	49.78%	679	1,616	49.78%	804
15		Total	$ 1,363		$ 679	$ 1,616		$ 804
16								
17		**Div 002**						
18	907	Supervision (1)	$ -	5.18%	$ -	$ -	5.18%	$ -
19	908	Customer Assistance	-	5.18%	-	-	5.18%	-
20	909	Informational Advertising (1)	-	5.18%	-	-	5.18%	-
21	910	Miscellaneous Customer Service and Informational (1)	-	5.18%	-	-	5.18%	-
22		Total	$ -		$ -	$ -		$ -
23								
24		**Div 012**						
25	907	Supervision (1)	$ -	5.64%	$ -	$ -	5.64%	$ -
26	908	Customer Assistance	-	5.64%	-	-	5.64%	-
27	909	Informational Advertising (1)	-	5.64%	-	-	5.64%	-
28	910	Miscellaneous Customer Service and Informational (1)	-	5.64%	-	-	5.64%	-
29		Total	$ -		$ -	$ -		$ -
30								
31		**Sales Expense**						
32								
33		**Div 009**						
34	911	Supervision	$ 253,382	100%	$ 253,382	$ 253,468	100%	$ 253,468
35	912	Demonstration and Selling (1)	143,981	100%	143,981	115,937	100%	115,937
36	913	Advertising	43,530	100%	43,530	35,170	100%	35,170
37	916	Miscellaneous Sales Expense	-	100%	-	-	100%	-
38		Total	$ 440,892		$ 440,892	$ 404,575		$ 404,575
39								
40		**Div 091**						
41	911	Supervision	$ 194,694	49.78%	$ 96,918	$ 210,011	49.78%	$ 104,543
42	912	Demonstration and Selling (1)	0	49.78%	0	0	49.78%	0
43	913	Advertising	1,230	49.78%	612	1,458	49.78%	726
44	916	Miscellaneous Sales Expense	0	49.78%	0	0	49.78%	0
45		Total	$ 195,923		$ 97,531	$ 211,468		$ 105,269
46								
47		**Div 002**						
48	911	Supervision	$ -	5.18%	$ -	$ -	5.18%	$ -
49	912	Demonstration and Selling (1)	20,339	5.18%	1,053	22,686	5.18%	1,174
50	913	Advertising	-	5.18%	-	-	5.18%	-
51	916	Miscellaneous Sales Expense	-	5.18%	-	-	5.18%	-
52		Total	$ 20,339		$ 1,053	$ 22,686		$ 1,174
53								
54		**Div 012**						
55	911	Supervision	$ -	5.64%	$ -	$ -	5.64%	$ -
56	912	Demonstration and Selling (1)	-	5.64%	-	-	5.64%	-
57	913	Advertising	-	5.64%	-	-	5.64%	-
58	916	Miscellaneous Sales Expense	-	5.64%	-	-	5.64%	-
59		Total	$ -		$ -	$ -		$ -

(1) Included in these accounts are advertising and promotional advertising expenses which are considered Non-recoverable and will be Excluded from O & M for ratemaking and therefore the Revenue Requirements. These amounts are shown properly classified on Schedule F-4, Advertising.

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
ADVERTISING
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:__x___Base Period___x___Forecasted Period — FR 16(8)(f)
Type of Filing:___X____Original________Updated________Revised — Schedule F-4
Workpaper Reference No(s). — Witness: Waller

		Base Period					Forecasted Period		
Line No.	Item (A)	Sales or Promotional Advertising	Safety or Req by Law Advertising	Total Utility	Kentucky Jurisdictional	Allocated Amount	Sales or Promotional Advertising	Kentucky Jurisdictional	Allocated Amount
1	**Div 009**								
2	Newspaper, Magazine,bill stuffer & Other	$ 184,693	$ 4,894	$ 189,587	100%	$ 189,587	$ 184,693	100%	$ 184,693
3									
4	**Div 091**								
5	Newspaper, Magazine,bill stuffer & Other	1,363	318,911	320,275	49.78%	159,433	1,363	49.78%	679
6									
7	**Div 002**								
8	Newspaper, Magazine,bill stuffer & Other	209,133	-	209,133	5.18%	10,827	209,133	5.18%	10,827
9									
10	**Div 012**								
11	Newspaper, Magazine,bill stuffer & Other	1,752	-	1,752	5.64%	99	1,752	5.64%	99
12									
13	**Grand Total**	$ 396,941	$ 323,806	$ 720,747		$ 359,946	$ 396,941		$ 196,297

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
PROFESSIONAL Service Expenses
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:__x___Base Period___x___Forecasted Period | FR 16(8)(f)
Type of Filing:___X_____Original________Updated________Revised | Schedule F-5
Workpaper Reference No(s).____________________ | Witness: Waller

		Base Period			Forecasted Period		
Line No.	Description	Total Utility	Kentucky Jurisdictional	Allocated Amount	Total Utility	Kentucky Jurisdictional	Allocated Amount
	Account 923 - Outside Services Employed						
1							
2	Div 009						
3	06111- Contract Labor	$ (22,453)	100%	$ (22,453)	$ (21,192)	100%	$ (21,192)
4	06121- Legal	$ 382,365	100%	382,365	$ 360,889	100%	360,889
5	Total	$ 359,911		$ 359,911	$ 339,697		$ 339,697
6							
7	Div 091						
8	06111- Contract Labor	$ 35,196	49.78%	$ 17,520	$ 56,218	49.78%	$ 27,985
9	06121- Legal	$ 168,250	49.78%	83,755	$ 268,746	49.78%	133,782
10	Total	$ 203,446		$ 101,275	$ 324,964		$ 161,767
11							
12	Div 002						
13	06111- Contract Labor	$ 10,575,222	5.18%	$ 547,492	$10,595,303	5.18%	$ 548,532
14	06121- Legal	$ 454,128	5.18%	23,511	$ 454,990	5.18%	23,555
15	Total	$ 11,029,350		$ 571,003	$11,050,293		$ 572,087
16							
17	Div 012						
18	06111- Contract Labor	$ 614,020	5.64%	$ 34,638	$ 448,998	5.64%	$ 25,329
19	06121- Legal	$ 48,342	5.64%	2,727.06	$ 35,350	5.64%	1,994.15
20	Total	$ 662,361		$ 37,365	$ 484,348		$ 27,323

Note: Rate Case related expenses are shown separately on Schedule F-6.

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Projected Rate Case Expense

Data:__X___Base Period__X___Forecasted Period — FR 16(8)(f)
Type of Filing:___X____Original________Updated ________Revised — Schedule F-6
Workpaper Reference No(s). — Witness: Waller

Line No	Description		Amount
1	Consulting		
2	Class Cost Study - P. Raab	$ 13,650	
3	Cost of Capital - Vander Weide, J. H.	16,200	
4	Depreciation - D. Watson	23,064	
5	sub-total		$ 52,914
6			
7	Legal Fees		
8	(J. Hughes/R. Hutchinson)		164,184
9			
10	Employee Expense		
11	(airfare, lodging, meals, etc.)		23,813
12			
13	Miscellaneous Expense		
14	(printing, advertising, etc.)		96,393
15			
16	Total Projected Rate Case Expense		$ 337,304
17			
18	Three (3) Year Amortization of Rate Case Expenses		$112,434.56

Data Source:
F.6 Schedule Rate Case Expenses.xls

Rate Case (3 year Amortization)

Case No. 2017-00349

	Regulated Asset Balance	Amortization Expense
Mar-18	0	0
Apr-18	0	0
May-18	164,401	8,719
Jun-18	155,682	8,719
Jul-18	146,963	8,719
Aug-18	138,244	8,719
Sep-18	129,525	8,719
Oct-18	120,806	8,719
Nov-18	112,087	8,719
Dec-18	103,368	8,719
Jan-19	94,649	8,719
Feb-19	85,930	8,719
Mar-19	77,211	8,719
	102,221	95,909
	(13 Month Average)	
Apr-19	68,492	8,719
May-19	59,773	8,719
Jun-19	51,054	8,719
Jul-19	42,335	8,719
Aug-19	33,616	8,719
Sep-19	24,897	8,719
Oct-19	16,178	8,719
Nov-19	7,459	7,459
Dec-19	0	0
Jan-20	0	0
Feb-20	0	0
Mar-20	0	0
Apr-20	0	0
May-20	0	0
Jun-20	0	0
Jul-20	0	0
Aug-20	0	0
Sep-20	0	0
Oct-20	0	0
Nov-20	0	0
Dec-20	0	0
Jan-21	0	0
Feb-21	0	0
Mar-21	0	0

Case No. 2018-00281

	Regulated Asset Balance	Amortization Expense
Mar-19	0	0
Apr-19	327,934	9,370
May-19	318,565	9,370
Jun-19	309,195	9,370
Jul-19	299,825	9,370
Aug-19	290,456	9,370
Sep-19	281,086	9,370
Oct-19	271,717	9,370
Nov-19	262,347	9,370
Dec-19	252,978	9,370
Jan-20	243,608	9,370
Feb-20	234,239	9,370
Mar-20	224,869	9,370
	255,140	112,435
Apr-20	215,500	9,370
May-20	206,130	9,370
Jun-20	196,760	9,370
Jul-20	187,391	9,370
Aug-20	178,021	9,370
Sep-20	168,652	9,370
Oct-20	159,282	9,370
Nov-20	149,913	9,370
Dec-20	140,543	9,370
Jan-21	131,174	9,370
Feb-21	121,804	9,370
Mar-21	112,435	9,370
Apr-21	103,065	9,370
May-21	93,695	9,370
Jun-21	84,326	9,370
Jul-21	74,956	9,370
Aug-21	65,587	9,370
Sep-21	56,217	9,370
Oct-21	46,848	9,370
Nov-21	37,478	9,370
Dec-21	28,109	9,370
Jan-22	18,739	9,370
Feb-22	9,370	9,370
Mar-22	(0)	9,370

	Balance Total	Amortization Total
Mar-18	0	0
Apr-18	0	0
May-18	164,401	8,719
Jun-18	155,682	8,719
Jul-18	146,963	8,719
Aug-18	138,244	8,719
Sep-18	129,525	8,719
Oct-18	120,806	8,719
Nov-18	112,087	8,719
Dec-18	103,368	8,719
Jan-19	94,649	8,719
Feb-19	85,930	8,719
Mar-19	77,211	8,719
Apr-19	396,426	18,089
May-19	378,338	18,089
Jun-19	360,249	18,089
Jul-19	342,161	18,089
Aug-19	324,072	18,089
Sep-19	305,984	18,089
Oct-19	287,895	18,089
Nov-19	269,806	16,829
Dec-19	252,978	9,370
Jan-20	243,608	9,370
Feb-20	234,239	9,370
Mar-20	224,869	9,370
	284,449	160,927
	(13 Month Average)	
Apr-20	215,500	9,370
May-20	206,130	9,370
Jun-20	196,761	9,370
Jul-20	187,391	9,370
Aug-20	178,022	9,370
Sep-20	168,652	9,370
Oct-20	159,282	9,370
Nov-20	149,913	9,370
Dec-20	140,543	9,370
Jan-21	131,174	9,370
Feb-21	121,804	9,370
Mar-21	112,435	9,370
Apr-21	103,065	9,370
May-21	93,695	9,370
Jun-21	84,326	9,370
Jul-21	74,956	9,370
Aug-21	65,587	9,370
Sep-21	56,217	9,370
Oct-21	46,848	9,370
Nov-21	37,478	9,370
Dec-21	28,109	9,370
Jan-22	18,739	9,370
Feb-22	9,370	9,370
Mar-22	(0)	9,370

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
CIVIC, POLITICAL and RELATED ACTIVITIES
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:__x___Base Period___x___Forecasted Period — FR 16(8)(f)
Type of Filing:___X____Original________Updated________Revised — Schedule F-7
Workpaper Reference No(s). — Witness: Waller

		Base Period			Forecasted Period		
Line No.	Item (A)	Total Utility	Kentucky Jurisdictional	Allocated Amount	Total Utility	Kentucky Jurisdictional	Allocated Amount
1	**Div 009**						
2	Donations (1)	$ -	100%	$ -	$ -	100%	$ -
3	Civic Duties (2)	-	100%	-	-	100%	-
4	Political Activities (3)	55,500	100%	55,500	55,500	100%	55,500
5	Other	-	100%	-	-	100%	-
6	Total	$ 55,500		$ 55,500	$ 55,500		$ 55,500
7							
8	**Div 091**						
9	Donations (1)	$ -	49.78%	$ -	$ -	49.78%	$ -
10	Civic Duties (2)	-	49.78%	-	-	49.78%	-
11	Political Activities (3)	2,202	49.78%	1,096	2,202	49.78%	1,096
12	Other	-	49.78%	-	-	49.78%	-
13	Total	$ 2,202		$ 1,096	$ 2,202		$ 1,096
14							
15	**Div 002**						
16	Donations (1)	$ -	5.18%	$ -	$ -	5.18%	$ -
17	Civic Duties (2)	-	5.18%	-	-	5.18%	-
18	Political Activities (3)	562,154	5.18%	29,103	562,154	5.18%	29,103
19	Other	-	5.18%	-	-	5.18%	-
20	Total	$ 562,154		$ 29,103	$ 562,154		$ 29,103
21							
22	**Div 012**						
23	Donations (1)	$ -	5.64%	$ -	$ -	5.64%	$ -
24	Civic Duties (2)	-	5.64%	-	-	5.64%	-
25	Political Activities (3)	-	5.64%	-	-	5.64%	-
26	Other	-	5.64%	-	-	5.64%	-
27	Total	$ -		$ -	$ -		$ -
28							
29	**Grand Total**	$ 619,856		$ 85,700	$ 619,856		$ 85,700

Notes:
(1) These donations represent Economic Development Contributions, all Other civic donations are Included on Schedule F-2.1, Charitable Contributions.

(2) All civic Memberships are Included on Schedule F-1, Social and Service Club Dues.

(3) These expenses are recorded below the line and therefore not included in O&M.

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
EMPLOYEE EXPENSE REPORT EXCLUSIONS

Data:__x___Base Period___x___Forecasted Period
Type of Filing:___X_____Original________Updated________Revised
Workpaper Reference No(s).____________________

FR 16(8)(f)
Schedule F-8
Witness: Waller

		Base Period			Forecasted Period		
Line No.	Description	Amount	Kentucky Jurisdictional	Allocated Amount	Amount	Kentucky Jurisdictional	Allocated Amount
1	Div 009	$ 34,636	100.00%	$ 34,636	$ 34,636	100%	$ 34,636
2							
3	Div 091	45,057	49.78%	22,429	45,057	49.78%	22,429
4							
5	Div 002	358,332	5.18%	18,551	358,332	5.18%	18,551
6							
7	Div 012	150,085	5.64%	8,467	150,085	5.64%	8,467
8							
9	Total Expense Report Exclusions	$ 588,109		$ 84,083	$588,109		$ 84,083

NOTE: This amount is included on ratemaking adjustments on Schedule C-2 and therefore excluded from the Revenue Requirements.

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
LEASE EXPENSE

Data:__x___Base Period___x___Forecasted Period — FR 16(8)(f)
Type of Filing:___X_____Original________Updated________Revised — Schedule F-9
Workpaper Reference No(s).____________________ — Witness: Waller

Line No.	Description	Monthly	Period affected	months	O&M factor	Total Amount
	Division 009 - Direct Kentucky					
1	Hopkinsville Office					$ 19,375
2						
3	Total lease expense to be avoided					$ 19,375
4						
5	Adjustment to O & M					$ (19,375)

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
INCENTIVE COMPENSATION EXPENSE

Data:__x___Base Period___x___Forecasted Period — FR 16(8)(f)
Type of Filing:___X_____Original________Updated________Revised — Schedule F-10
Workpaper Reference No(s).____________________ — Witness: Waller

Line No.	Div	Category	Total	Allocation Factor	Allocated Totals
		Variable Pay & Management Incentive Plans			
1	2	VPP & MIP	4,619,227	5.18%	239,143
2	12	VPP & MIP	0	5.64%	0
3	91	VPP & MIP	846,073	49.78%	421,175
4	9	VPP & MIP	0	100.00%	0
5		Total Allocated VPP & MIP Plans			660,318
		Restricted Stock Plans			
6	2	RSU-LTIP - Time Lapse	1,992,899	5.18%	103,175
7		RSU-LTIP - Performance Based	2,176,608	5.18%	112,686
8	12	RSU-LTIP - Time Lapse	51,607	5.64%	2,911
9		RSU-LTIP - Performance Based	58,921	5.64%	3,324
10	91	RSU-LTIP - Time Lapse/Performance I	161,851	49.78%	80,569
11					
12	9	RSU-LTIP - Time Lapse	0	100.00%	0
13		RSU-LTIP - Performance Based	0	100.00%	0
14		Total Allocated Restricted Stock Plans			302,665
15		Grand Total Allocated Expense			962,983
		Payroll Tax Expense Adjustment			$ 62,594

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
2017-00349 O&M Adjustments

Data:__x___Base Period___x___Forecasted Period
Type of Filing:___X_____Original________Updated________Revised
Workpaper Reference No(s).____________________

FR 16(8)(f)
Schedule F-10
Witness: Waller

Line No.	Division	Budget Sub Account	Amount	Allocation	Total
1					
2	002	Directors Retirement Expenses - 04113	3,664,608	5.18%	189,721
3	002	Removal of Retirement Benefits	1,161,419	5.18%	60,128
4	012	Removal of Retirement Benefits	664,153	5.64%	37,466
5	009	Removal of Retirement Benefits	339,023	100.00%	339,023
6	091	Removal of Retirement Benefits	164,728	49.78%	82,002
7					
8		Grand Total			708,340

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
PAYROLL Costs
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

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

FR 16(8)(g)
Schedule G-1
Witness: Waller

Line No.	Description	% of Labor	Total Company Unadjusted	Jurisdictional	Base Period Jurisdictional Unadjusted	Adjustments	Forecasted Period Jurisdictional ADJUSTED
1	Payroll Costs						
2	Labor		$ 12,385,641	100.00%	$ 12,385,641	$ 220,260	$ 12,605,902
3							
4	Employee Benefits						
5	PENSION & RETIREMENT Income Plan	4.18%	$ 517,502	100.00%	$ 517,502	$ 9,203	$ 526,705
6	FAS 106	-0.96%	(118,386)	100.00%	(118,386)	(260,729)	(379,115)
7	Employee INSURANCE PLANS	21.51%	2,663,627	100.00%	2,663,627	47,369	2,710,996
8	ESOP PLAN Contributions	5.66%	700,421	100.00%	700,421	12,456	712,877
9				100.00%	0	0	
10	Total Employee BENEFITS		$ 4,006,507		$ 4,006,507	$ 172,762	$ 4,179,269
11							
12	Payroll Taxes						
15	Payroll Taxes		$ 837,558	100.00%	837,558	39,300	$ 876,858
16	Total Payroll Taxes		$ 837,558		$ 837,558	$ 39,300	$ 876,858
17							
18	Total Payroll Costs		$ 17,229,707		$ 17,229,707	$ 432,322	$ 17,662,029

Exhibit GKW-R-1
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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Payroll Analysis by Employee Classifications/Payroll Distribution/Total Company
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:___X____Base Period___X____Forecasted Period — FR 16(8)(g)
Type of Filing:___X_____Original________Updated — Schedule G-2
Workpaper Reference No(s). — Witness: Waller

Line No.	Description	2013	% Change	2014	% Change	2015	% Change	2016	% Change	2017	% Change	Base Period	% Change	Forecasted Period
		Most Recent Five Fiscal Years*												
1														
2														
3	Man Hours													
4	Straight Time Hours	410,825	-0.16%	410,171	-0.16%	409,514	2.03%	417,832	-6.33%	391,365	7.36%	420,160	0.00%	420,160
5	OverTime Hours	18,473	15.01%	21,246	6.62%	22,653	6.69%	24,169	0.97%	24,403	3.35%	25,220	0.00%	25,220
6	Total Manhours	429,298	0.49%	431,417	0.17%	432,167	3.06%	442,001	0.76%	415,768	7.12%	445,380	0.00%	445,380
7	Ratio of OverTime Hours													
8	to Straight-Time Hours	4.497%		5.180%		5.532%		5.784%		6.235%		6.002%		6.002%
9														
10	Labor Dollars													
11	Straight-Time Dollars	10,464,861	1.29%	10,599,619	3.54%	10,974,506	7.17%	11,761,379	-3.29%	11,374,568	-0.15%	11,357,943	1.16%	11,489,523
12	OverTime Dollars	657,642	15.99%	762,824	9.91%	838,415	11.26%	932,823	5.65%	985,485	4.28%	1,027,699	8.63%	1,116,379
13	Total Labor Dollars	11,122,503	2.16%	11,362,443	3.96%	11,812,921	7.46%	12,694,202	-2.63%	12,360,053	0.21%	12,385,641	1.78%	12,605,902
14	Ratio of OverTime Dollars													
15	to Straight-Time Dollars	6.284%		7.197%		7.640%		7.931%		8.664%		9.048%		9.716%
16														
17	O&M Labor Dollars	5,094,063	-1.84%	5,000,231	1.61%	5,080,812	4.26%	5,185,743	-1.32%	5,163,405	2.59%	5,297,266	-3.40%	5,117,357
18	Ratio of O&M of Labor Dollars													
19	to Total Labor Dollars	45.800%		44.007%		43.011%		40.851%		41.775%		42.769%		40.595%
20														
21	Employee Benefits													
22	Total Employee Benefits	6,062,525	1.42%	6,148,916	-14.27%	5,271,508	-13.75%	4,546,845	-1.38%	4,483,971	-10.65%	4,006,507	4.31%	4,179,269
23	Employee Benefits Expensed	2,972,341	-5.54%	2,807,746	-18.40%	2,291,156	-15.77%	1,929,818	0.48%	1,939,113	-11.63%	1,713,543	-0.99%	1,696,574
24	Ratio of Employee Benefits													
25	Expensed to Total Employee													
26	Benefits	49.028%		45.662%		43.463%		42.443%		43.245%		42.769%		40.595%
27														
28	Payroll Taxes													
29	Total Payroll Taxes	842,968	32.66%	1,118,268	-19.88%	895,950	10.61%	991,045	6.66%	1,057,091	-20.77%	837,558	4.69%	876,858
30	Payroll Taxes Expensed	335,033	0.08%	335,294	4.12%	349,097	8.03%	377,118	-11.10%	335,253	6.85%	358,215	-0.63%	355,960
31	Ratio of Payroll Taxes													
32	Expensed to Total Payroll													
33	Taxes	39.744%		29.983%		38.964%		38.053%		31.715%		42.769%		40.595%
34														
35	Employee Levels													
36	Average Employee Levels	211	1.90%	215	-1.86%	211	1.90%	215	-4.19%	206	-1.94%	202	0.00%	202
37	Year end Employee Levels	213	2.35%	218	-2.29%	213	2.35%	218	-7.34%	202	0.00%	202	0.00%	202

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Executive Compensation
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

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

FR 16(8)(g)
Schedule G-3
Witness: Waller

Line No.	Description	% of Labor FY17	FY18	Wtd Avg	Base Period Company Unallocated	Adjustments	Forecasted Period Company Unallocated
1	Includes 7 Officers						
2							
3	Gross Payroll						
4	Salary				$ 3,378,041	$ 135,122	$ 3,513,163
5	Other Allowances and Compensation				9,311,146	372,446	$ 9,683,592
6	Total Salary and Compensation				$ 12,689,188	$ 507,568	$ 13,196,755
7							
8	Employee Benefits	FY17	FY18	Wtd Avg			
9	Pensions	6.00%	4.40%	4.80%	$ 162,146	$ 6,486	$ 168,632
10	SERP				$ 2,758,681	110,347	$ 2,869,029
11	Other Benefits	28.00%	28.70%	28.53%	963,586	38,543	1,002,130
12	Total Employee Benefits				$ 3,884,414	$ 155,377	$ 4,039,790
13							
14	Payroll Taxes						
15	FICA/FUTA/SUTA				$ 247,462	$ 9,898	$ 257,361
16	Total Payroll Taxes				$ 247,462	$ 9,898	$ 257,361
17							
18	Total Compensation				$ 16,821,063	$ 672,843	$ 17,493,906

NOTE: This schedule contains confidential information, detail of these numbers are available upon request.

Positions included on this schedule are:
CEO
SVP, Utility Operations (created in January 2017)
SVP, General Counsel (vacant from Mar17-Jul17, filled in Aug-17)
President and COO
SVP, CFO
SVP, Safety and Enterprise
SVP, Human Resources

These costs are total costs for Atmos Energy Corporation, a portion of which are allocated to Kentucky.
*Wtd Avg is 9 mos of FY18 and 3 months of FY17

Exhibit GKW-R-1
Page 106 of 121

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Computation of Gross Revenue Conversion Factor
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:__X___Base Period___X___Forecasted Period — FR 16(8)(h)
Type of Filing:___X____Original________Updated ________Revised — Schedule H-1
Workpaper Reference No(s). — Witness: Waller

Line No.	Description		**Base Year** Percentage of Incremental Gross Revenue	**Test Year** Percentage of Incremental Gross Revenue
1	Operating Revenue		100.000000%	100.000000%
2	Less: Uncollectible Accounts Expense		0.500000%	0.500000%
3	Less: PSC Fees		0.200000%	0.200000%
4	Net Revenues		99.300000%	99.300000%
5	SIT Rate	5.00%	4.965000%	4.965000%
6	Income before Federal Income Tax		94.335000%	94.335000%
7	Federal Income Tax @	21%	19.810400%	19.810400%
8	Operating Income Percentage		74.524600%	74.524600%
9	Gross Revenue Conversion Factor			
10	(100 % divided by Income after Income Tax)		1.341839	1.341839

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Comparative Income Statement
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:___X____Base Period___X____Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).________________

FR 16(8)(i)1
Schedule I
Witness: Gillham, Waller, Densman

	Most Recent Five Calendar Years					Base Year	Test Year			
	2013	2014	2015	2016	2017	12/31/2018	3/31/2020	2020	2021	2022
INCOME STATEMENT	$	$	$	$		$	$	$	$	$
Operating Revenues										
Gas service revenue	148,865	180,147	153,228	129,827	144,870	154,820	150,248	149,814	148,321	147,963
Transportation	12,587	14,311	15,087	15,748	17,215	17,013	14,881	14,881	14,881	14,881
Other revenue	1,517	2,424	2,153	1,857	2,017	3,329	4,589	4,584	4,571	4,568
Total Operating Revenues	162,968	196,882	170,468	147,431	164,102	175,163	169,718	169,279	167,773	167,412
Purchase gas	94,657	118,107	87,746	61,180	70,880	83,882	78,382	77,907	76,310	75,848
Gross Profit	68,311	78,774	82,721	86,251	93,222	91,280	91,336	91,372	91,463	91,564
Operating Expenses										
Direct O&M	14,377	14,815	14,927	14,518	16,031	15,500	12,723	18,914	19,149	19,392
Allocated O&M	11,534	12,036	12,874	12,708	11,829	13,031	14,499	11,053	11,362	11,757
Depreciation & amortization	14,919	16,846	18,636	19,121	19,379	20,643	23,102	25,167	28,556	32,382
Taxes - other than income	3,871	4,648	7,343	5,919	6,336	6,492	7,512	9,637	10,834	12,165
Total Operating Expenses	44,701	48,344	53,779	52,266	53,575	55,666	57,835	64,771	69,901	75,696
Operating income(loss)	23,610	30,430	28,942	33,985	39,647	35,614	33,500	26,601	21,562	15,868
Other income										
Interest Income	83	69	40	42	32	32	32	32	32	32
Performance based rates	2,659	2,705	2,795	2,792	3,246	3,246	3,246	3,000	3,000	3,000
Donations	(194)	(299)	(427)	(355)	(361)	(361)	(361)	(361)	(361)	(361)
Other Income	(514)	(456)	(344)	(391)	(403)	(403)	(403)	(403)	(403)	(403)
Total other income	2,033	2,019	2,063	2,087	2,514	2,514	2,514	2,268	2,268	2,268
Interest Charges										
Total interest charges	6,436	6,419	6,744	7,377	8,009	8,488	9,383	7,485	9,101	11,203
Income Before Taxes	19,208	26,030	24,261	28,695	34,152	29,640	26,631	21,384	14,729	6,933
Provision for income taxes	7,420	9,672	9,884	9,516	9,697	7,395	6,644	4,040	2,327	321
Net Income	11,788	16,358	14,377	19,178	24,455	22,245	19,987	17,343	12,402	6,612

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Revenue Statistics
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:___X____Base Period___X____Forecasted Period
Type of Filing:___X_____Original_________Updated
Workpaper Reference No(s).

FR 16(8)(i)2
Schedule I
Witness: Gillham, Densman

Line No.	Description	2013	2014	2015	2016	2017	Base Period 12/31/2018	Forecasted Period 3/31/2020	2020	2021	2022
		Most Recent Five Calendar Years									
1	Revenue by Customer Class:										
2	Residential	$ 96,055,210	$115,327,134	$ 97,211,019	$ 85,596,832	$ 94,138,422	$ 99,146,045	$ 96,519,490	$ 96,326,563	$ 95,527,942	$ 95,391,680
3	Commercial	39,938,784	49,294,804	42,476,905	34,032,004	38,222,731	42,884,783	41,608,020	$ 41,428,893	$ 40,924,733	$ 40,763,656
4	Industrial	4,796,885	5,845,776	5,705,427	4,441,439	6,400,150	5,847,533	5,370,385	$ 5,338,211	$ 5,242,091	$ 5,211,956
5	Public Authority & Other	8,073,794	9,679,607	7,834,566	5,756,388	6,108,524	6,942,114	6,749,807	$ 6,720,022	$ 6,626,214	$ 6,595,813
6	Unbilled										
7	Total	$ 148,864,673	$180,147,322	$ 153,227,918	$ 129,826,663	$ 144,869,827	$154,820,476	$150,247,702	$ 149,813,689	$ 148,320,980	$ 147,963,105
8	Number of Customer by Class:										
9	Residential	153,904	155,702	155,281	155,597	156,174	157,307	157,713	157,875	158,200	158,525
10	Commercial	17,318	17,435	17,333	17,339	17,354	17,446	17,446	17,446	17,446	17,446
11	Industrial	207	204	201	205	206	215	215	215	215	215
12	Public Authority & Other	1,575	1,576	1,561	1,550	1,549	1,535	1,535	1,535	1,535	1,535
13	Total	173,004	174,917	174,376	174,692	175,282	176,502	176,909	177,071	177,396	177,721
14	Average Revenue per Class:										
15	Residential	$ 624	$ 741	$ 626	$ 550	$ 603	$ 630	$ 612	$ 610	$ 604	$ 602
16	Commercial	2,306	2,827	2,451	1,963	2,203	2,458	2,385	2,375	2,346	2,337
17	Industrial	23,183	28,703	28,362	21,630	31,094	27,138	24,924	24,774	24,328	24,188
18	Public Authority & Other	5,125	6,141	5,019	3,714	3,945	4,524	4,399	4,379	4,318	4,298

(1) Unbilled Revenue is not included in the appropriate customer class.

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
SALES STATISTICS
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:___X____Base Period___X____Forecasted Period
Type of Filing:___X_____Original________Updated
Workpaper Reference NO(S).____________________

FR 16(8)(i)3
Schedule I
Witness: Gillham, Densman

Line No.	Description	Most Recent Five Calendar Years 2013 Mcf	2014 Mcf	2015 Mcf	2016 Mcf	2017	Base Period 12/31/2018 Mcf	Forecasted Period 3/31/2020 Mcf	2020 Mcf	2021 Mcf	2022
1	Sales by Customer Class:										
2	Residential	10,662,876	11,757,007	10,133,138	8,859,272	8,360,876	10,051,263	10,083,093	10,087,189	10,107,961	10,128,734
3	Commercial	5,112,548	5,657,641	4,981,322	4,436,288	4,415,168	5,216,701	5,216,701	5,216,701	5,216,701	5,216,701
4	Industrial	807,006	780,039	706,192	1,021,718	1,517,001	991,585	991,585	991,585	991,585	991,585
5	Public Authority & Other	1,185,264	1,241,310	1,055,743	896,168	824,971	962,459	962,459	962,459	962,459	962,459
6	Unbilled										
7											
8	Total	17,767,695	19,435,997	16,876,396	15,213,446	15,118,017	17,222,008	17,253,838	17,257,933	17,278,706	17,299,479
9											
10	Number of Customer by Class:										
11	Residential	153,904	155,702	155,281	155,597	156,174	157,307	157,713	157,875	158,200	158,525
12	Commercial	17,318	17,435	17,333	17,339	17,354	17,446	17,446	17,446	17,446	17,446
13	Industrial	207	204	201	205	206	215	215	215	215	215
14	Public Authority & Other	1,575	1,576	1,561	1,550	1,549	1,535	1,535	1,535	1,535	1,535
15											
16	Total	173,004	174,917	174,376	174,692	175,282	176,502	176,909	177,071	177,396	177,721
17											
18	Average Volume per Class:										
19	Residential	69	76	65	57	54	64	64	64	64	64
20	Commercial	295	324	287	256	254	299	299	299	299	299
21	Industrial	3,900	3,830	3,510	4,976	7,370	4,602	4,602	4,602	4,602	4,602
22	Public Authority & Other	752	788	676	578	533	627	627	627	627	627

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Cost of Capital Summary
Base Period: Twelve Months Ended December 31, 2018

FR 16(8)(j)
Schedule J-1
Sheet 1 of 1
Witness: Christian

Data:__X___Base Period______Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).____________________

Line No.	Class of Capital	Workpaper Reference		Amount	Percent of Total	Cost Rate	Weighted Cost
		(A)		(B)	(C)	(D)	(E)
				$000	%	%	%
	Capital Structure						
6	SHORT-TERM DEBT	J-3	$	281,542	3.47%	2.40%	0.08%
7	LONG-TERM DEBT	J-3		3,068,315	37.83%	5.22%	1.97%
8	PREFERRED STOCK	J-4		0	0.00%	0.00%	0.00%
9	COMMON EQUITY		$	4,760,181	58.69%	10.40%	6.10%
10	Total Capital		$	8,110,038	100.00%		8.15%

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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
13 Month Average Capital Structure
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020

Data:__X___Base Period___X___Forecasted Period — FR 16(8)(j)
Type of Filing:___X____Original________Updated ________Revised — Schedule J-1
Workpaper Reference No(s).__________________ — Witness: Christian

PROPOSED RATES

Line No.	Class of Capital	Workpaper Reference	Base Period Amount	Base Period Percent of Total	Base Period Cost Rate	Base Period Weighted Cost	Forecasted Period Amount	Forecasted Period Percent of Total	Forecasted Period Cost Rate	Forecasted Period Weighted Cost
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
			$000	%	%	%	$000	%	%	%
1	SHORT-TERM DEBT		281,542	3.47%	2.40%	0.08%	203,112	2.21%	3.40%	0.08%
2	LONG-TERM DEBT		3,068,315	37.83%	5.22%	1.97%	3,659,779	39.73%	4.56%	1.81%
3	Total DEBT		3,349,857	41.30%		2.05%	3,862,891	41.94%		1.89%
4	PREFERRED STOCK		0	0.00%	0.00%	0.00%	0	0.00%	0.00%	0.00%
5	COMMON EQUITY		4,760,181	58.70%	10.40%	6.10%	5,348,195	58.06%	10.40%	6.04%
6	Other Capital		0	0.00%	0.00%	0.00%	0	0.00%	0.00%	0.00%
7	Total Capital		8,110,038	100.0%		8.15%	9,211,086	100.0%		7.93%

CURRENT RATES

Line No.	Class of Capital	Workpaper Reference	Base Period Amount	Base Period Percent of Total	Base Period Cost Rate	Base Period Weighted Cost	Forecasted Period Amount	Forecasted Period Percent of Total	Forecasted Period Cost Rate	Forecasted Period Weighted Cost
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
			$000	%	%	%	$000	%	%	%
8	SHORT-TERM DEBT		281,542	3.47%	2.40%	0.08%	203,112	2.21%	3.40%	0.08%
9	LONG-TERM DEBT		3,068,315	37.83%	5.22%	1.97%	3,659,779	39.73%	4.56%	1.81%
10	Total DEBT		3,349,857	41.30%		2.06%	3,862,891	41.94%		1.89%
11	PREFERRED STOCK		0	0.00%	0.00%	0.00%	0	0.00%	0.00%	0.00%
12	COMMON EQUITY		4,760,181	58.70%	7.81%	4.58%	5,348,195	58.06%	6.30%	3.66%
13	Other Capital		0	0.00%	0.00%	0.00%	0	0.00%	0.00%	0.00%
14	Total Capital		8,110,038	100.0%		6.64%	9,211,086	100.0%		5.55%

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
ANNUALIZED SHORT-TERM DEBT
as of December 31, 2017

FR 16(8)(j)
Schedule J-2
Sheet 1 of 1
Witness: Christian

Data:__X___Base Period______Forecasted Period
Type of Filing:___X____Original_________Updated _________Revised
Workpaper Reference No(s).______________________

Line No.	Issue	Amount Outstanding	(1) Interest Rate	Effective Annual Cost	Composite Interest Rate
	(A)	(B) $000	(C)	(D) $000	(E=D/B)
1	AVERAGE SHORT-TERM DEBT	$ 281,542	1.414%	$ 3,982	
2	COMMITMENT FEE & BANK ADMIN			$ 2,778	
3	TOTAL SHORT-TERM DEBT	$ 281,542		$ 6,760	2.40%

NOTES:

(1) Interest Rate is the actual average rate for 12 Months Ended June 30, 2018

Exhibit GKW-R-1

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
AVERAGE ANNUALIZED LONG-TERM DEBT
Base Period: Twelve Months Ended December 31, 2018

Data:__X___Base Period______Forecasted Period — FR 16(8)(j)
Type of Filing:___X____Original________Updated ________Revised — Schedule J-3
Workpaper Reference No(s). — Witness: Christian

Line No.	Issue		13 Mth Avg. Amount Outstanding	Interest Rate	Effective Annual Cost	Composite Interest Rate
	(A)		(B)	(C)	(D)	(E=D/B)
1	6.75% Debentures Unsecured due July 2028	$	150,000,000	6.75%	$10,125,000	
2	6.67% MTN A1 due Dec 2025		10,000,000	6.67%	667,000	
3	5.95% Sr Note due 10/15/2034		200,000,000	5.95%	11,900,000	
4	Sr Note 5.50% Due 06/15/2041		400,000,000	5.50%	22,000,000	
5	8.50% Sr Note due 3/15/2019		450,000,000	8.50%	38,250,000	
6	4.15% Sr Note due 1/15/2043		500,000,000	4.15%	20,750,000	
7	4.125% Sr Note due 10/15/2044		750,000,000	4.13%	30,937,500	
8	3% Sr Note dues 6/15/2027		500,000,000	3.00%	15,000,000	
9	$200MM 3YR Sr Credit Facility (Est. 9/22/16)		125,000,000	3.06%	3,825,000	
10	Total	$	3,085,000,000		$153,454,500	
11						
12	Annualized Amortization of Debt Exp. & Debt Dsct.				$6,580,966	
13	Less Unamortized Debt Discount		$4,425,158			
14	Less Unamortized Debt Expenses		($21,110,455)			
15						
16						
17						
18	Total LONG-TERM DEBT		$3,068,314,702.82		160,035,466	**5.22%**

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
EMBEDDED Cost of PREFERRED STOCK

FR 16(8)(j)
Schedule J-4
Sheet 1 of 1
Witness: Christian

Data:__X___Base Period__X___Forecasted Period
Type of Filing:___X____Original________Updated
Workpaper Reference No(s).____________________

Line No.	Dividend Rate, TYPE, PAR Amount	Date Issued (A)	Amount Outstanding (B)	Premium or Discount (C)	Issue Expense (D)	Gain or Loss on Reacquired Stock (E)	Net Proceeds (F=B+C-D+E)	Cost Rate At Issue (G)	Annualized Dividends (H=GXB)

Atmos Energy Corporation has no PREFERRED STOCK OUTSTANDING at this time.

Exhibit GKW-R-1
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Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Cost of Capital Summary
Thirteen Month Average as of March 31, 2019

Data:_____Base Period___X___Forecasted Period — FR 16(8)(j)
Type of Filing:___X____Original________Updated ________Revised — Schedule J-1
Workpaper Reference No(s).________________ — Witness: Christian

Line No.	Class of Capital	Workpaper Reference	Amount	Percent of Total	Cost Rate	Weighted Cost
		(A)	(B) $000	(C)	(D) %	(E) %
	Capital Structure					
6	SHORT-TERM DEBT		$ 203,112	2.21%	3.40%	0.08%
7	LONG-TERM DEBT	J-3	3,659,779	39.7%	4.56%	1.81%
8	PREFERRED STOCK	J-4	0	0.0%	0.00%	0.00%
9	COMMON EQUITY		$ 5,348,195	58.1%	10.40%	6.04%
10	Total Capital		$ 9,211,086	100.0%		7.93%

Exhibit GKW-R-1
Page 116 of 121

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
AVERAGE ANNUALIZED SHORT-TERM DEBT
as of March 31, 2019

Data:_____Base Period___X___Forecasted Period — FR 16(8)(j)
Type of Filing:___X____Original________Updated ________Revised — Schedule J-2
Workpaper Reference No(s).____________________ — Witness: Christian

	Issue	Amount Outstanding	Interest Rate	Effective Annual Cost	Composite Interest Rate
	(A)	(B)	(C)	(D)	(E=D/B)
		$000		$000	
1	AVERAGE SHORT-TERM DEBT (1)	203,112	1.98%	4,016	
2	COMMITMENT FEE			2,887	
3	TOTAL SHORT-TERM DEBT	203,112		6,903	3.40%

NOTES:

(1) Interest Rate is the actual average rate for 12 Months Ended December 31, 2018.

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
AVERAGE ANNUALIZED LONG-TERM DEBT
Forecasted Test Period: Twelve Months Ended March 31, 2020

FR 16(8)(j)
Schedule J-3
Sheet 1 of 1
Witness: Christian

Data:_____Base Period___X___Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).____________________

Line No.	Issue (A)	13 Mth Average Amount Outstanding (B)	Interest Rate (C)	Effective Annual Cost (D)	Composite Interest Rate (E=D/B)
1	6.75% Debentures Unsecured due July 2028	$ 150,000,000	6.75%	$ 10,125,000	
2	6.67% MTN A1 due Dec 2025	10,000,000	6.67%	667,000	
3	5.95% Sr Note due 10/15/2034	200,000,000	5.95%	11,900,000	
	4.3% Sr Note due 10/1/2048	600,000,000	4.30%	25,800,000	
4	Sr Note 5.50% Due 06/15/2041	400,000,000	5.50%	22,000,000	
5	4.125% Sr Note due 3/15/2049	450,000,000	4.14%	18,630,000	
6	4.15% Sr Note due 1/15/2043	500,000,000	4.15%	20,750,000	
7	4.125% Sr Note due 10/15/2044	750,000,000	4.13%	30,937,500	
8	3% Sr Note due 6/15/2027	500,000,000	3.00%	15,000,000	
9	$200MM 3YR Sr Credit Facility (Est. 9/22/16)	125,000,000	3.49%	4,362,500	
10	Total	$ 3,685,000,000		$ 160,172,000	
11					
12	Annualized Amortization of Debt Exp. & Debt Dsct.			6,896,326	
13	Less Unamortized Debt Discount	$1,471,550			
14	Less Unamortized Debt Expenses	($26,692,691)			
15					
16					
17					
18	Total LONG-TERM DEBT	$ 3,659,778,860		$ 167,068,326	4.56%

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2018-00281
Comparative Financial Data
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended March 31, 2020
and 10 Most Recent Calendar Years

Data:__X___Base Period___X___Forecasted Period — FR 16(8)(k)
Type of Filing:_______Original________Updated ____X____Revised — Schedule K
Workpaper Reference No(s). — Witness: Gillham, Martin, and Waller

Line No.	Description	Forecasted Period	Base Period	Most Recent Ten Calendar Years - as Reported 2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
1	Plant Data: ($000)												
2	Plant in Service by functional class:												
3	Intangible Plant	773	773	128	128	128	128	128	128	128	128	128	128
4	Production & Gathering Plant	0	0	0	0	0	636	901	901	901	901	901	901
5	Underground Storage	15,018	15,021	13,329	12,454	11,560	10,792	9,630	10,104	9,388	7,731	7,540	6,950
6	Transmission Plant	31,004	31,455	31,784	31,814	31,808	31,877	32,962	32,836	33,144	31,189	31,202	28,807
7	Distribution Plant	673,469	583,188	517,179	472,849	413,302	381,623	340,200	323,036	296,493	283,474	271,463	260,621
8	General Plant	42,857	40,871	21,675	21,271	18,126	16,683	15,589	15,238	16,000	15,103	14,696	15,422
9	Acquisition Adjustments			3,279	3,279	3,279	3,279	3,279	3,279	3,279	3,337	3,337	3,337
10													
11	Gross Plant	763,121	671,308	587,374	541,795	478,203	445,018	402,689	385,522	359,333	341,863	329,267	316,166
12	Less: Accumulated depreciation	199,413	197,392	175,150	167,228	165,298	160,839	158,300	151,849	150,795	147,462	144,016	139,212
13	Net plant in Service	563,709	473,916	412,224	374,567	312,905	284,179	244,389	233,673	208,538	194,401	185,251	176,954
14													
15	Construction Work in Progress	39,130	39,130	32,838	10,146	26,310	12,708	16,578	6,006	3,306	7,197	4,851	5,215
16													
17	Total CWIP	39,130	39,130	32,838	10,146	26,310	12,708	16,578	6,006	3,306	7,197	4,851	5,215
18													
19	Total	602,839	513,046	445,062	384,713	339,215	296,887	260,967	239,679	211,844	201,598	190,102	182,169
20													
21	% of Construction financed internally	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
22													
23													
24	Capital structure: **(Total Company)**												
25	(based on year-end accounts))												
26	Short-term debt ($000)	203,112	281,542	447,745	829,811	457,927	196,695	367,984	570,929	206,396	126,100	72,550	350,542
27	Long-term debt ($000)	3,659,779	3,068,315	3,067,045	2,438,779	2,437,515	2,455,986	2,455,671	1,956,305	2,206,117	1,809,551	2,169,400	2,119,792
28	Preferred stock ($000)			0	0	0	0	0	0	0	0	0	0
29	Common equity ($000)	5,348,195	4,760,181	3,898,666	3,463,059	3,194,797	3,086,232	2,580,409	2,359,243	2,255,421	2,178,348	2,176,761	2,052,492
30													
31	Total	9,211,086	8,110,038	7,413,456	6,731,649	6,090,239	5,738,913	5,404,064	4,886,477	4,667,934	4,113,999	4,418,711	4,522,826
32													
33	Condensed Income Statement data: ($000)												
34	Operating Revenues	169,718	175,163	164,102	147,431	170,468	196,882	162,968	134,778	149,662	156,816	190,356	244,308
35	Operating Expenses (excludes Federal			0	0	0	0	0	0	0	0	0	0
36	and State Taxes, includes gas cost)	136,218	139,548	124,455	113,447	141,526	166,452	139,358	112,027	126,219	136,649	176,587	224,348
37	State Income Tax (current))			0	0	0	0	0	0	0	0	0	0
38	Federal Income Tax (current)			0	0	0	0	0	0	0	0	0	0
39	Federal and State Income Tax - net	6,644	7,395	9,697	9,516	9,884	9,671	7,060	8,157	8,094	5,654	2,889	6,985
40	Investment tax credits	0	0	0	0	0	0	0	0	0	0	0	0
41	Operating Income	26,856	28,219	29,950	24,468	19,058	20,759	16,550	14,594	15,349	14,513	10,880	12,976
42	AFUDC	0	0	379	179	182	139	88	101	22	286	199	160

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Type of Filing:________Original________Updated ____X____Revised
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FR 16(8)(k)
Schedule K
Witness: Gillham, Martin, and Waller

Line No.	Description	Forecasted Period	Base Period	Most Recent Ten Calendar Years - as Reported 2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
43	Other Income net	2,514	2,514	2,514	2,087	2,063	2,019	2,033	2,046	2,657	1,748	2,278	2,529
44	Income available for fixed charges	29,369	30,733	32,843	26,734	21,303	22,917	18,671	16,741	18,028	16,547	13,357	15,665
45	Interest charges	9,383	8,488	8,388	7,556	6,926	6,559	6,524	5,612	5,792	6,270	6,633	6,138
46	Net Income	19,987	22,245	24,455	19,178	14,377	16,358	12,147	11,129	12,236	10,277	6,724	9,527
47	Preferred dividends accrual	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	Earnings available for common equity	19,987	22,245	24,455	19,178	14,377	16,358	12,147	11,129	12,236	10,277	6,724	9,527
49													
50	AFUDC - % of Net Income	0.00%	0.00%	1.55%	0.93%	1.27%	0.85%	0.72%	0.91%	0.18%	2.78%	2.96%	1.68%
51	AFUDC - % of earnings available for												
52	common equity	0.00%	0.00%	1.55%	0.93%	1.27%	0.85%	0.72%	0.91%	0.18%	2.78%	2.96%	1.68%
53													
54													
55													
56	Costs of Capital (1)												
57	Embedded cost of short-term debt (%)	3.40%	2.40%	1.68%	1.12%	1.09%	1.49%	1.17%	1.22%	1.03%	3.23%	6.80%	4.40%
58	Embedded cost of long-term debt (%)	4.56%	5.22%	5.45%	5.89%	5.90%	6.03%	6.26%	6.51%	6.75%	6.88%	6.90%	6.10%
59	Embedded cost of preferred stock (%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
60													
61	Fixed Charge Coverage: (1)												
62	Pre-Tax Interest Coverage	3.84	4.49	6.03	5.72	5.26	4.69	3.91	3.06	2.97	3.00	2.84	3.06
63	Pre-Tax Interest Coverage (Excluding AFUDC)	3.84	4.49	6.06	5.74	5.28	4.70	3.92	3.04	2.95	2.99	2.80	3.12
64	After Tax Interest Coverage	3.13	3.62	4.18	4.01	3.63	3.24	2.89	2.36	2.26	2.23	2.20	2.26
65	SEC Coverage	3.80	4.43	5.45	5.16	4.77	4.11	3.63	2.84	2.78	2.78	2.55	2.76
66	After Tax Interest Coverage (Excluding AFUDC	3.13	3.62	4.21	4.03	3.65	3.25	2.91	2.35	2.24	2.21	2.16	2.31
67	Indenture Provision Coverage	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
68	After Tax Fixed Charge Coverage	4.86	6.91	3.81	3.64	3.32	3.02	2.70	2.21	2.13	2.08	2.18	2.15
69													
70	Stock and Bond Ratings: (1)												
71	Moody's Bond Rating	N/A	A2	A2	A2	A2	A2	Baa1	Baa1	Baa1	Baa2	Baa2	Baa3
72	S&P Bond Rating	N/A	A	A	A	A-	A-	A-	BBB+	BBB+	BBB+	BBB+	BBB
73	Moody's Preferred Stock Rating	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
74	S&P Preferred Stock Rating	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
75													
76	Common Stock Related Data: (1)												
77	Shares Outstanding Year End (000)	N/A	N/A	106,105	103,931	101,479	100,388	90,640	90,240	90,296	90,164	92,552	90,814
78	Shares Outstanding - Weighted	N/A	N/A	0	0	0	0	0	0	0	0	0	0
79	Average (Monthly) (000)	N/A	N/A	106,100	103,524	101,892	97,608	91,711	91,172	90,652	92,422	91,620	89,941
80	Earnings Per Share - Weighted Avg. ($)	N/A	N/A	3.73	3.38	3.09	2.96	2.64	2.37	2.27	2.20	2.07	1.99
81	Dividends Paid Per Share ($)	N/A	N/A	1.80	1.68	1.56	1.48	1.40	1.38	1.36	1.34	1.32	1.30
82	Dividends Declared Per Share ($)	N/A	N/A	1.80	1.68	1.56	1.48	1.40	1.38	1.36	1.34	1.32	1.30
83	Dividend Payout Ratio (Declared	N/A	N/A										
84	Basis) (%)	N/A	N/A	48%	50%	50%	50%	53%	58%	60%	61%	64%	65%
85	Market Price - High (Low)	N/A	N/A										

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Data:__X___Base Period___X___Forecasted Period — FR 16(8)(k)
Type of Filing:_______Original________Updated ____X____Revised — Schedule K
Workpaper Reference No(s).________________ — Witness: Gillham, Martin, and Waller

Line No.	Description	Forecasted Period	Base Period	Most Recent Ten Calendar Years - as Reported 2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
86	1st Quarter - High ($)	N/A	N/A	74.730	64.250	58.080	47.060	36.860	35.400	31.720	30.060	27.880	29.460
87	1st Quarter - Low ($)	N/A	N/A	68.960	57.820	47.350	41.080	33.200	30.970	29.100	27.390	21.170	26.110
88	2nd Quarter - High ($)	N/A	N/A	80.400	74.330	58.810	48.010	42.690	33.150	34.980	29.520	25.950	28.960
89	2nd Quarter - Low ($)	N/A	N/A	73.210	61.740	52.020	44.190	35.110	30.600	31.510	26.520	20.200	25.090
90	3rd Quarter - High ($)	N/A	N/A	85.540	81.320	56.410	53.400	44.870	35.070	34.940	29.980	26.370	28.540
91	3rd Quarter - Low ($)	N/A	N/A	78.900	70.600	51.280	46.940	38.590	30.910	31.340	26.410	22.810	25.810
92	4th Quarter - High ($)	N/A	N/A	88.690	81.160	58.180	52.680	45.190	36.940	34.320	29.810	28.800	28.250
93	4th Quarter - Low ($)	N/A	N/A	82.420	71.880	51.480	47.010	39.400	34.940	28.870	26.820	24.650	25.490
94	Book Amount Per Share (Year-end) ($)	N/A	N/A	36.745	33.450	31.350	31.620	28.140	25.877	24.880	23.570	23.759	22.820
95													
96	(1) Based on fiscal year-end of parent company												
97													
98	Rate of Return Measures (1)												
99	Return On Common Equity (Average)	6.3%	8.0%	10.8%	10.5%	10.0%	10.2%	9.8%	8.3%	8.6%	8.7%	8.7%	8.8%
100	Return On Total Capital (Average)	5.6%	6.7%	5.6%	5.5%	5.2%	5.2%	4.8%	4.0%	4.3%	4.4%	4.3%	4.3%
101	Return On Net Plant in Service (Average)	4.8%	6.0%	4.5%	4.5%	4.5%	4.5%	4.3%	3.6%	3.8%	4.1%	4.3%	4.5%
102													
103	Other Financial and Operating Data:												
104	Mix of Sales: (MMcf)												
105	Residential	10,083	10,051	8,724	9,094	9,826	11,729	10,695	8,433	10,187	10,735	10,261	10,855
106	Commercial	5,217	5,217	4,575	4,538	4,845	5,650	5,143	3,972	4,642	5,049	4,659	5,017
107	Industrial	992	992	1,517	1,048	693	810	811	995	821	724	960	1,715
108	Public authority & Other Sales	962	962	859	916	1,025	1,234	1,179	980	1,111	1,192	1,176	1,253
109	Unbilled	0	0										
110	Total Mix of Sales	17,254	17,222	15,675	15,596	16,389	19,423	17,828	14,380	16,761	17,700	17,056	18,839
111													
112	Mix of Fuel: (MMcf)												
113		0	0	0	0	0	0	0	0	0	0	0	0
114	Other	17,582	17,549	16,060	15,417	18,606	21,324	18,367	17,441	16,748	17,596	17,034	18,790
115													
116	Total MIX of Fuel (2)	17,582	17,549	16,060	15,417	18,606	21,324	18,367	17,441	16,748	17,596	17,034	18,790
117													
118	Composite Depreciation Rate	2.96%	2.79%	3.12%	3.33%	3.66%	3.50%	3.31%	3.49%	3.58%	3.40%	3.43%	3.17%

(1) Based on fiscal year-end of parent company, except for Base Period & Test Period which are based on Atmos Energy Corporation, Kentucky. Return calculations cannot be used for revenue requirement purposes
(2) Kentucky gas purchases by accounting month.

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BEFORE THE PUBLIC SERVICE COMMISSION
COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY	**)**	
	)	
CORPORATION FOR AN ADJUSTMENT	**)**	**Case No. 2018-00281**
	)	
OF RATES AND TARIFF MODIFICATIONS	**)**	

REBUTTAL TESTIMONY OF JOHN S. MCDILL

INDEX TO THE REBUTTAL TESTIMONY
OF JOHN S. MCDILL, WITNESS FOR
ATMOS ENERGY CORPORATION

TABLE OF CONTENTS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John S. McDill. I am Vice President, Pipeline Safety for Atmos Energy Corporation ("Atmos Energy" or the "Company"). My business address is 5430 LBJ Freeway, Dallas, Texas.

I. EXECUTIVE SUMMARY

Atmos Energy's commitment to safety, and the safety of its pipeline system, is a core value. When a natural gas pipeline fails, the repercussions can be catastrophic. Federal and state regulations have prompted natural gas pipeline operators to leverage technology and tools in order to better analyze and understand the condition of their assets. This approach enables operators to understand and foresee specific risks on their system and to take appropriate mitigative steps to repair or replace pipelines proactively. Atmos Energy realizes that balancing safety and financial cost is an important policy objective. However, the Company believes that the goal of maintaining low-cost service should not be allowed to jeopardize initiatives that are required to maintain a safe and reliable system.

In furtherance of our acute focus on maintaining a safe and reliable system, Atmos Energy carefully monitors its system, devotes resources when necessary and prioritizes work as appropriate. This includes the replacement of identified pipelines made of materials prone to leaks and potential failure. This approach is intended to proactively protect our customers and the public in general from property damage and personal injuries (including fatalities) by permitting Atmos Energy to monitor and inspect its system and replace pipe when needed, rather than doing so reactively. In light of the age of some of the pipe on the Company's

Kentucky system and the heightened expectations of federal and state policy, the Kentucky Public Service Commission ("Commission") should encourage utilities to implement, fund and continue programs and capital investment that will improve the safety and reliability of their natural gas infrastructure.

II. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated in December 1986 from Mississippi State University with a Bachelor of Science degree in Petroleum Engineering. In terms of my professional background, I joined Mississippi Valley Gas Company in April 1987 as a graduate engineer. Early in my career, I participated in a training program where I spent a number of weeks, and in many cases months, working in meter reading, service and the construction areas of our company. I have held various positions of increasing responsibility since 1987 in natural gas operations, measurement and customer service. These include Manager of Measurement Service, Jackson District Superintendent, Assistant District Manager, Jackson District Manager. In January 2003, I became Vice President of Operations for the Southern Region of Mississippi when Mississippi Valley Gas was acquired by Atmos Energy. For a majority of my 32 years of service, I have been directly responsible for the service, construction, compliance and operational activities of approximately 150 employees while serving approximately 70,000 customers while in the roles of District Superintendent and District Manager of Jackson, Mississippi. In 2003, my role expanded with my promotion to Vice President of Operations to include the southern operating region of Mississippi, providing service to approximately 130,000 customers. This included the development, execution and monitoring of capital and operations and maintenance ("O&M") budgets. I served in that role until the time of my promotion to my current position in May 2012.

Within the industry, I have served on the Southern Gas Association's ("SGA") Distribution Operation and Engineering Committee and the American Gas Association's ("AGA") Managing Committee. I currently serve as Chair of the SGA Pipeline Safety Council and I am a member of the AGA Board Safety Committee.

Q. WHAT ARE YOUR DUTIES IN YOUR CURRENT ROLE?

A. In my position as Vice President, Pipeline Safety I provide strategic direction and plan oversight for pipeline safety and compliance, employee safety, and physical security activities for our eight-state operation. I monitor the effectiveness of enterprise pipeline safety activities and seek opportunities for continuous improvement. I monitor federal and state pipeline safety activities as well as external incident investigations, and work with industry associations and regulators on pipeline safety activities.

I work with our operating divisions to ensure we meet or exceed compliance, operational, and jurisdictional standards, and I oversee our written procedures, plans and policies.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE COMMISSION?

A. No, not in Kentucky, but I submitted testimony before the Colorado Public Utilities Commission in 2015 in Proceeding No. 15AL-0299G and 2017 in Proceeding No. 17AL-0429G. I have also submitted testimony before the State Corporation Commission of Kansas in Docket Nos. 16-ATMG-079-RTS and 15-GIMG-343-GIG, as well as the Mississippi Public Service Commission in Docket No. GC-123-0081-00.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My rebuttal testimony addresses Mr. Kollen's assumption that the current funding for pipeline replacement is adequate to maintain the safety and reliability of the gas system and to meet recently enacted regulatory standards. My testimony has three purposes: (1) to describe the federal and state regulations governing pipeline safety and Atmos Energy's federally-mandated Distribution Integrity Management Program ("DIMP"); (2) to provide background information regarding Atmos Energy's prior requests for approval of investments in the integrity of the Company's system and the corresponding mechanisms to recover those investments; and (3) to explain why, from a policy perspective, continuing the Company's accelerated replacement of aging infrastructure is in the public interest. In addition to my testimony, Mr. Gregory Smith provides in his direct and rebuttal testimony an overview of the benefits that have been derived to date from the Company's investment in its Kentucky gas system by describing the work Atmos

Energy has completed as well as those that the Company plans to complete with future capital investment. Further, Mr. Martin explains in his direct testimony why the Company is requesting continuation of its forecasted capital investment and how customers in Kentucky will benefit from the program. Also, Mr. Waller in his direct and rebuttal testimony describes the recovery calculations and the effects of regulatory lag and explains how Atmos Energy allocates capital to accommodate the work necessary to continue the replacing infrastructure at a reasonable cost.

Q. ARE YOU PROVIDING ANY EXHIBITS IN THIS PROCEEDING?

A. Yes. I am providing the following Attachments:

- Exhibit JSM-R-1 is a letter from the Pipeline and Hazardous Materials Safety Administration ("PHMSA") to the National Association of Regulatory Utility Commissioners ("NARUC") dated December 19, 2011, and the White Paper on State Pipeline Infrastructure Replacement Programs.
- Exhibit JSM-R-2 is the Federal Energy Regulatory Commission ("FERC") Policy Statement entitled "Cost Recovery Mechanisms for Modernization of Natural Gas Facilities."
- Exhibit JSM-R-3 is the resolution adopted by the NARUC on July 24, 2013.
- Exhibit JSM-R-4 is AGA's Commitment to Enhancing Safety.
- Exhibit JSM-R-5 is United States Secretary of Transportation Secretary La Hood's Call to Action.
- Exhibit JSM-R-6 is United States Secretary of Transportation Secretary La Hood's March 28, 2011 letter to the states.

III. <u>ATMOS ENERGY'S SYSTEM INVESTMENT</u>

Q. WHAT IS ATMOS ENERGY'S MOST FUNDAMENTAL OBJECTIVE?

A. Atmos Energy's most fundamental objective is to provide safe and reliable gas service to all of its customers.

Q. PLEASE DESCRIBE ATMOS ENERGY'S COMMITMENT TO SAFETY.

A. Throughout the Atmos Energy system, our employees are responsible for approximately 76,000 miles of natural gas pipelines, serving about three million natural gas distribution customers in more than 1,400 communities of varying sizes in eight states. For each mile of pipe we maintain and for every community we serve, ensuring the safety and reliability of our gas transmission and distribution infrastructure stands as our Company's core commitment.

Q. WHY IS ATMOS ENERGY'S COMMITMENT TO SAFETY A CORE VALUE?

A. Atmos Energy's acute focus on safety and reliability stems from an awareness of the implications of the Company's actions for the safety of our customers, communities, and employees. Our commitment to safety and reliability permeates throughout our culture. We have worked and continue to work with regulators, industry associations, and other stakeholders to take proactive measures to strengthen safety in Kentucky and our industry.

Additionally, against the backdrop of natural gas incidents in other parts of the country, Atmos Energy is compelled to continually seek and assess opportunities to improve upon the safety of our operations in an effort to reduce, wherever feasible, the potential for system integrity threats.

Q. IS THE COMPANY'S ONLY GOAL TO PROVIDE SAFE AND RELIABLE SERVICE?

A. No, we must be fiscally responsible as well. Under well-established principles of utility regulation, utilities have the duty to provide customers with safe and reliable utility service at reasonable rates and in turn utility shareholders are allowed the opportunity to earn a fair rate of return on their investments. However, in balancing these competing considerations, it is critical that neither Atmos Energy nor this Commission allow the goal of providing low-cost service to jeopardize the undertaking of initiatives to maintain a safe and reliable system.

Q. IS ATMOS ENERGY'S KENTUCKY PIPELINE SYSTEM IN JEOPARDY?

A. No. Atmos Energy's natural gas pipeline system in Kentucky is not in imminent danger of catastrophic failure. However, as pipe ages, the likelihood of pipeline failure increases, thereby also increasing the likelihood of an occurrence of pipeline failure that rises to the level of catastrophic. For this reason, delaying pipe replacement until there is an imminent threat to public safety is obviously not good public policy.

Q. IS THE ATMOS ENERGY PIPELINE SYSTEM IN KENTUCKY SAFE?

A. Yes. Atmos Energy is very proud that, overall, our system has proven to be safe and reliable. While no one can guarantee there will never be an incident, we can and do monitor and inspect our system, identify risks, and implement remedies when appropriate. However, past success is not a guarantee of future safety and Atmos Energy must remain vigilant in monitoring, inspecting, maintaining, and improving the system. Failure to do so will inevitably lead to a less safe system.

Q. CAN ATMOS ENERGY CONTINUE TO PROVIDE SAFE AND RELIABLE SERVICE IN KENTUCKY?

A. Yes. By being proactive with our maintenance, monitoring, and continuing the accelerated replacement efforts currently ongoing, Atmos Energy can minimize the risks of incidents. We are continuing to focus on maintaining and improving our safety and reliability record. At the same time, the natural gas utility industry is being driven to be even more proactive in identifying and mitigating risks. Atmos Energy's goal is to work with our regulators to continue a safety program that best serves the interests of our customers, the communities in which they live, and the Kentucky public. The Company's accelerated replacement efforts are a critical component of Atmos Energy's ability to achieve that goal.

Q. WHY IS THE COMPANY'S CAPITAL INVESTMENT IN INFRASTRUCTURE CRITICAL TO ATMOS ENERGY'S COMMITMENT OF MAINTAINING A SAFE AND RELIABLE SYSTEM?

A. Atmos Energy's accelerated replacement of aging infrastructure is critical to the Company's ability to comply with federal pipeline safety regulations and directives and maintain an effective pipe replacement program. Under the federal regulatory requirements discussed in more detail below, Atmos Energy must regularly inspect its system and proactively identify risks. Part of this proactive identification of risks involves acknowledging and investigating the known risks identified through the experience of the broader natural gas utility industry, not merely those identified only through inspections of the Company's system. Once those risks are identified, Atmos Energy must be able to fund a systematic program designed to mitigate or, where possible, eliminate those risks, something the Attorney General fails to understand.

Q. WHY IS THE CONTINUATION OF THE COMPANY'S ACCELERATED REPLACEMENT OF AGING INFRASTRUCTURE ON ITS SYSTEM VITALLY IMPORTANT?

A. Atmos Energy does not restrict capital expenditures that are necessary to address safety considerations and make certain that identified risks are mitigated. However, the Commission's approval of forward-looking capital recovery facilitates a regulatory environment where safety concerns are able to receive their appropriate priority. As is discussed in more detail in Mr. Waller's direct and rebuttal testimony, such a regulatory environment is necessary to the utility's long-term ability to continue to attract and invest capital to mitigate risks.

Q. HAVE OTHER JURISDICTIONS IN WHICH ATMOS ENERGY OPERATES ALSO CREATED SUCH A REGULATORY ENVIRONMENT?

A. Yes. Texas has enacted policy measures that mandate that the Company replace a certain percentage of high relative risk assets on an annual basis and provided methods for the Company to recover that investment. Similarly, Louisiana, Mississippi, Tennessee, Virginia and Colorado have also enacted similar policy measures to mitigate risks by permitting recovery of infrastructure investment on an annual basis.

Q. HAS ATMOS ENERGY HISTORICALLY REPLACED PIPE AS PART OF ITS NORMAL OPERATIONS?

A. Yes. The assessment, rehabilitation and replacement of aging pipelines has been a normal part of the utility business; however, the Company has focused more on these activities as we continue to comply with the changed regulatory framework that governs the way we respond to and mitigate risk. The Commission has acknowledged the changed regulatory framework and has stated: "To the extent that the pipeline eligible for recovery poses a safety risk to the utility's customers, service areas, and employees, the Commission has proven itself to be in favor of accelerated replacement."[1]

In this way, federal regulations and directives have necessitated the systematic and proactive assessment and replacement of pipelines. In turn, this systematic and proactive approach now requires the commitment of capital investment at higher levels than have been previously included in our rate structure. This is a nationwide phenomenon and is not limited to either Atmos Energy or the Commonwealth of Kentucky.

Q. DESCRIBE THE ONGOING LEVEL OF REPLACEMENT FOR MAINS AND SERVICE LINES FOR THE COMPANY'S OVERALL SYSTEM.

A. From Fiscal Year 2012 through 2018, Atmos Energy has replaced approximately 3,500 miles of distribution and transmission pipelines. Over the next five years, we expect to replace 5,000-6,000 miles of distribution and transmission pipelines. In

[1] *ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES AND TARIFF MODIFICATIONS*, Case No. 2017-00349, Order at 39 (Ky. PSC May 3, 2018) at 39.

addition, the Company is currently replacing approximately 50,000 steel service lines annually across its service territories. Mr. Smith provides in his direct and rebuttal testimony an overview of the replacement projects undertaken by the Company in Kentucky.

Q. HOW WOULD YOU DESCRIBE THE KENTUCKY REGULATORY ENVIRONMENT AS IT RELATES TO SAFETY?

A. It appears clear that the Commission understands the vital importance of having a regulatory structure in place for utilities to mitigate pipeline safety risks. As mentioned previously, the Commission in Atmos Energy's last rate case reiterated "[t]o the extent that the pipeline eligible for recovery poses a safety risk to the utility's customers, service areas, and employees, the Commission has proven itself to be in favor of accelerated replacement." Company witness Greg Smith discusses in his direct and rebuttal testimony in a more detail the continued need for accelerated replacement of Atmos Energy's Kentucky system. In addition, the Commission has also recently noted that risk and the need for pipe replacement for aged infrastructure is not bare steel specific. In its Final Order in Case No. 2018-00086, the Commission commented specifically on Aldyl-A replacement:

> *The Commission is aware of the risk associated with Aldyl-A pipe. As Delta states in its application, Aldyl-A is subject to slow crack growth that leads to eventual rupture of the pipe. Furthermore, Aldyl-A has been the subject of several PHMSA bulletins, the most recent of which is attached hereto as Appendix B. Due to the significant amount of pre-1983 Aldyl-A pipe that exists in the Delta system, the Commission finds that the Aldyl-A pipe should be replaced in a 15-year time frame. As of the date of this Order, the newest of the Aldyl-A pipe on Delta's system is at least 35 years old. At the conclusion of Delta's proposed PRP, the newest of the Aldyl-A pipe will be at least 50 years old. Given that Aldyl-A pipe was*

> *installed on Delta's system as early as 1965, and some has already been in service nearly 55 years, the Commission finds that now is an appropriate time to plan for the replacement of Aldyl-A pipe. The Commission expects Delta to continue to prioritize its PRP to replace pipe based on risk, and pipe in high-consequence areas, whether it be bare steel or Aldyl-A pipe.*[2]

Company witness Greg Smith discusses in greater detail the Aldyl-A pipe that exists on Atmos Energy's system in his rebuttal testimony as one reason for Atmos Energy's targeted capital expenditures beyond bare steel replacement.

IV. ATMOS ENERGY'S PIPELINE REPLACEMENT IS IN THE PUBLIC INTEREST

Q. IS ATMOS ENERGY'S PIPELINE REPLACEMENT IN THE PUBLIC INTEREST?

A. Yes. Inherent in the federal regulations, the integrity rules, and the associated directives, is the requirement that pipeline operators do what is reasonably necessary to ensure public safety. The assessment, rehabilitation and proactive replacement of aging infrastructure are all essential to enhancing the safety and integrity of the system. In light of the regulatory developments discussed previously, the replacement projects are reasonable and necessary to ensure the continued safe and reliable operation of our system. Promoting safety and investing in the integrity of our system in a systematic manner is squarely in the public interest.

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[2] *Electronic Adjustment of the Pipe Replacement Program Rider of Delta Natural Gas Company, Inc.*, Case No. 2018-00086, *Order* at p. 3-4 (Ky. PSC August 21, 2018).

Q. DO FEDERAL REGULATORS AGREE THAT RATE RECOVERY MECHANISMS ENCOURAGING PIPLINE REPLACEMENT ARE IN THE PUBLIC INTEREST?

A. Yes. In December of 2011, in connection with the publication of a White Paper on State Pipeline Infrastructure Replacement Programs sponsored by the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA"), the PHMSA Administrator specifically highlighted the public interest in infrastructure replacement programs in a letter to the President of the National Association of Regulatory Utility Commissioners ("NARUC"). The White Paper then offered the following conclusion:

> "[Pipeline infrastructure replacement] programs play a vital role in protecting the public by ensuring the prompt rehabilitation, repair, or replacement of high-risk gas distribution infrastructure."[3]

Even though the Company still has a Pipeline Replacement Program ("PRP") Rider for bare steel in Kentucky, the recent order by the Commission in Case No. 2017-00349 requiring the PRP to be on a historic test period goes against industry trends encouraging a proactive approach to accelerated replacement, and also incurs regulatory lag on pipeline replacement investments more fully explained by Company witnesses Mr. Waller and Mr. Martin.

[3] Attachment JSM-R-1, White Paper on State Infrastructure Replacement Programs at 17.

Q. HAS THE FEDERAL ENERGY REGULATORY COMMISSION ("FERC") ADDRESSED THIS ISSUE?

A. Yes. On April 16, 2015, FERC issued a Policy Statement addressing cost recovery mechanisms for modernization of interstate natural gas facilities in FERC Docket No. PL15-1-000. The Policy Statement states that FERC has established a policy allowing interstate natural gas pipelines to seek recovery of certain capital expenditures made to replace infrastructure through a surcharge mechanism. On page 1 of its Policy Statement, FERC stated clearly that its intent is to "provide greater certainty regarding the ability of interstate natural gas pipelines to recover the costs of modernizing their facilities and infrastructure to enhance the efficient and safe operations of their systems."

The FERC's Policy Statement outlined the standards it will require interstate pipelines to satisfy in order to establish alternate ratemaking mechanisms such as surcharges or trackers to allow them to recover the costs of replacing obsolete infrastructure and thereby enhance the efficient and safe operations of their pipeline systems. Columbia Gas Transmission, a FERC-regulated pipeline that operates in Kentucky, has such a mechanism and has used it to improve its pipeline system dramatically over the past several years. The Company's decision to file for capital recovery on a forward-looking basis, rather than a historic test period, is consistent with FERC's Policy Statement as can be more fully discussed by Company witness Greg Waller. A copy of FERC's Policy Statement is attached to my testimony as Exhibit JSM-R-2.

Q. DID FERC'S POLICY STATEMENT ADDRESS THE ISSUE OF SAFETY AS A DRIVER FOR THE NEED TO REPLACE AGING INFRASTRUCTURE?

A. Yes. In Paragraph 26 of the Policy Statement, FERC stated:

> "With regard to safety and reliability…recent pipeline accidents, including the September 2010 pipeline rupture in San Bruno, California, demonstrate the potential consequence of aging pipeline facilities that are not properly repaired, rehabilitated or replaced. OPS states that 59% of existing natural gas pipelines were built before 1970 and 69% of existing natural gas pipelines were built before 1980. DOE notes that more than half of the country's natural gas and gathering infrastructure is over 40 years old. As OPS points out, while aging pipelines are not inherently risky, older facilities have been exposed to more threats and were likely constructed without the benefit of today's safety standards or quality materials."

Q. HAS NARUC ALSO RECOGNIZED THE NEED FOR ACCELERATED INVESTMENT IN GAS INFRASTRUCTURE?

A. Yes. In response to PHMSA's letter, NARUC issued a resolution on July 24, 2013 encouraging state commissions to "consider adopting alternative rate recovery mechanisms as necessary to accelerate the modernization, replacement and expansion of the nation's natural gas pipeline systems."[4]

Q. IS CONTINUATION OF ATMOS ENERGY'S CAPITAL EXPENDITURES APPROPRIATE GIVEN THE CIRCUMSTANCES?

A. Yes. Natural gas pipeline safety and reliability are issues of state-wide concern, and Kentucky residents, regardless of where they reside, deserve to have natural gas systems that are safe and reliable.

[4] See Exhibit JSM-R-3 - NARUC Resolution dated July 24, 2013.

In addition to the integrity risks associated with aging infrastructure and continued degradation of pipeline materials, many of the Company's distribution systems traverse areas with greater populations than existed when the pipes were initially constructed, potentially resulting in an increased risk of injury and property damage should an incident occur. Addressing these issues and concerns directly results in a significant increase in the capital investment and O&M needed to comply with federal requirements.

V. PIPELINE SAFETY REGULATIONS

Q. IN YOUR POSITION, ARE YOU FAMILIAR WITH FEDERAL AND STATE REGULATIONS REGARDING PIPELINE SAFETY AND INTEGRITY?

A. Yes.

Q. IS ATMOS ENERGY SUBJECT TO THE PHMSA'S RULES AND REGULATIONS REGARDING GAS DISTRIBUTION PIPELINE SAFETY?

A. Yes. Atmos Energy is subject to the PHMSA rules and regulations as those are promulgated by the U.S. Department of Transportation ("DOT"). The Kentucky Public Service Commission is the agent for DOT safety enforcement.

Q. DO PIPELINE SAFETY REGULATIONS SPECIFY THE FULL EXTENT OF ACTIONS A PRUDENT OPERATOR IS EXPECTED TO UNDERTAKE WHEN OPERATING ITS SYSTEM?

A. No. The pipeline safety regulations, or code (including the federal code and complementary codes adopted by the states), were never intended to be all-inclusive. In other words, the federal code prescribes the minimum that should be done to construct, operate, and maintain a natural gas system. As described previously, inherent in the code and the integrity rules is the requirement that pipeline operators do what is reasonably necessary to maintain public safety.

Q HOW HAVE NATURAL GAS UTILITY INDUSTRY GROUPS RESPONDED WITH RESPECT TO NATURAL GAS PIPELINE OPERATORS' GOING BEYOND MINIMUM CODE?

A. Atmos Energy is an active member of the AGA and has provided input on the development of the AGA's "Commitment to Enhancing Safety" which was released in May 2012 and updated in February 2016.[5] The report was prepared at the request of federal and state officials having oversight of pipeline safety. Atmos Energy fully supports the Commitment to Enhancing Safety and is implementing actions that the report lays out as a part of our ongoing commitment to providing safe and reliable service to our Kentucky customers.

Q. PLEASE SUMMARIZE THE PHMSA REGULATIONS APPLICABLE TO ATMOS ENERGY IN KENTUCKY.

A. The PHMSA regulations applicable to our Kentucky operations are codified at Code of Federal Regulations ("CFR") Title 49 (Transportation), Part 192 (Transportation of Natural Gas and Other Gas by Pipeline: Minimum Federal Safety Standards). These regulations prescribe minimum safety requirements for pipeline facilities and the transportation of gas (Section 192.1); define "pipeline

[5] Exhibit JSM-R-4 is a copy of the AGA's Commitment to Enhancing Safety.

facilities" as "new and existing pipeline, rights-of-way, and any equipment, facility, or building used in the transportation of gas..." (Section 192.3); define the "transportation of gas" as "the gathering, transmission, or distribution of gas by pipeline or the storage of gas, in or affecting interstate or foreign commerce (Section 192.3); and define an "operator" as an entity that "engages in the transportation of gas" (Section 192.3). Atmos Energy is an "operator" under Part 192 of PHMSA's regulations.

Q. WHAT IS THE "PIPES ACT" AND HOW DID THAT IMPACT PIPELINE SAFETY REGULATIONS FOR DISTRIBUTION SYSTEMS?

A. In 2006, Congress passed the Pipeline Inspection, Protection, Enforcement and Safety Act ("PIPES Act"). Pursuant to the PIPES Act, in 2009 PHMSA published the Integrity Management Program for Gas Distribution Pipelines Rule (49 CFR Part 192, Subpart P) ("2009 Final Rule").

Q. AS A GENERAL MATTER, WHAT IS REQUIRED UNDER THE 2009 FINAL RULE?

A. The 2009 Final Rule requires each operator, including Atmos Energy, to create and maintain a written distribution pipeline safety and integrity management program or "DIMP." The integrity management approach is "designed to promote continuous improvement in pipeline safety by requiring operators to identify and invest in risk control measures <u>beyond core regulatory requirements</u>."[6] Indeed, the "basic principle underlying integrity management" is that "operators should

[6] Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines, 74 Fed. Reg. 63906 at 63906 (Dec. 4, 2009) (emphasis supplied) ("2009 Final Rule").

identify and understand the threats to their pipelines and apply their safety resources commensurate with the importance of each threat."[7]

Q. PLEASE FURTHER DESCRIBE A DIMP.

A. A DIMP specifies how the utility will identify, assess, prioritize, and evaluate risks to the integrity of distribution lines and the manner in which those risks will be mitigated or eliminated. As explained above, Atmos Energy is subject to the DIMP regulations and is required to have a DIMP in place. Additionally, Atmos Energy submits annual reports to the Commission, as is further required by the PHMSA and Commission's rules.

Q. WHY DID THE PHMSA PROMULGATE THE 2009 FINAL RULE?

A. The history behind the 2009 Final Rule, and the studies that lead up to it, are well discussed in the Notice of Proposed Rulemaking for the 2009 Final Rule.[8] In short, the 2009 Final Rule was the end result of the recognition by the gas distribution industry, elected officials, and state and federal regulators that the "integrity management" approach, already in place for transmission pipelines, should be extended to distribution pipelines. PHMSA recognized the special nature of distribution pipelines, and stated:

> "Incidents on distribution pipelines kill and injure more people than incidents on gas transmission pipelines. As noted above, nearly two million miles of distribution pipelines are in operation in the U.S., compared with approximately 300,000 miles of gas transmission pipelines. In addition, distribution pipelines are almost all located in populated areas. Large portions of gas transmission pipelines traverse rural areas where there are few people. Largely because of these differences, incidents on distribution pipelines in 2006

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[7] 2009 Final Rule, 74 Fed. Reg. at 63906.

[8] Notice of Proposed Rulemaking, 73 Fed. Reg. 36015.

> resulted in five times as many fatalities (16 vs. 3) and six times as many serious injuries (25 vs. 4) as those on gas transmission pipelines, even though the total number of incidents on each type of pipeline was about the same (141 vs. 134). Because of the much larger number of miles of distribution pipeline, the normalized rate of fatalities and injuries (i.e., the number per 100,000 miles) is similar for the two types of lines, with a slightly lower rate for distribution lines. As described further below, the trend in gas distribution incidents involving fatalities and serious injuries (those requiring hospitalization) was downward from 1990-2002. In the years since, however, the number has again started to increase."[9]

These appear to have been some of the PHMSA's core concerns in promulgating the 2009 Final Rule.

Q. DOES THE 2009 FINAL RULE PROVIDE ANY ADDITIONAL INFORMATION?

A. Yes, it does. PHMSA's 2009 Final Rule (74 Fed. Reg. 63906) notes:

> "PHMSA has considered these comments [regarding the necessity of the rule] but still considers it necessary to issue a rule requiring integrity management for distribution pipelines. While accidents may continue to occur, that does not mean that reasonable actions should not be taken to avoid those accidents that could be prevented. PHMSA concludes that the flexibility inherent in the rule, as modified in response to other comments (described below), adequately addresses concerns based on differences among distribution pipelines. PHMSA also concludes that the changes made in response to other comments will reduce implementation costs and that the rule will be cost-beneficial. PHMSA is working with State pipeline safety agencies to increase the level of Federal financial support provided for State programs. PHMSA notes that the vast majority of distribution pipeline operators and State regulators, and the associations that represent them, supported the proposed rule. The existing rules help assure an admirable safety level. Still, significant accidents continue to occur, if infrequently. Experience has shown that incidents are most often caused by a combination of circumstances. These circumstances represent risks for the pipeline involved, but may not affect other pipelines. It is thus not practical to create additional prescriptive requirements to

[9] Notice of Proposed Rulemaking, 73 Fed. Reg. 36015 at 36017.

address these pipeline-specific risks. This rule (as the integrity management requirements for other types of pipelines that preceded it) requires that operators evaluate their pipelines to identify the risks important to their circumstances and take appropriate actions to address those risks.

This… [integrity management ("IM")] regulation for distribution operators requires an operator to conduct a comprehensive evaluation of its system to better identify threats to the system, to implement additional measures to help prevent accidents from occurring and to mitigate the consequences if an accident does occur. IM provides for a more systematic and comprehensive approach to preventing failures. Accordingly, PHMSA considers this the most effective means to effect further reductions in the number of pipeline incidents. The regulatory analysis supporting this rule considers the improvement in safety that is expected to result and explicitly recognizes the current low frequency of serious accidents."

Q. DID THE RULEMAKING PROCESS PROVIDE ANY INSIGHT INTO THE STATES' ROLES IN DISTRIBUTION PIPELINE SAFETY MEASURES?

A. Yes. PHMSA emphasized the importance of oversight performed directly by the States. PHMSA stated specifically:

"States must implement the minimum standards established by PHMSA but have a variety of ways in which they can oversee distribution pipeline safety. They can simply mirror the Federal pipeline safety program; they can impose additional requirements, beyond the Federal minimum; they can engage in special oversight programs with individual operators or groups of operators; <u>or finally, they can provide incentives for safety improvements, often through their rate-setting authority</u>. (emphasis added)

It is appropriate that the principal actions for regulating distribution pipeline safety rest with the States. States need to balance safety and affordability. They need to ensure that the particular needs of their citizenry are fulfilled...."[10]

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[10] Notice of Proposed Rulemaking, 73 Fed. Reg. 36015 at 36017.

Q. HAVE FEDERAL REGULATORS PROVIDED ANY ADDITIONAL GUIDANCE ON PIPELINE INTEGRITY, SUBSEQUENT TO THE PASSAGE OF THE DIMP REGULATIONS?

A. Yes. After the passage of the 2009 Final Rule but prior to the August 2, 2011 deadline for gas distribution operators to develop their DIMPs, the DOT took further action. In response to fatal explosions caused by natural gas pipeline failures in Allentown, Pennsylvania and San Bruno, California, the Secretary of Transportation Ray LaHood issued a Call to Action.[11] That Call to Action sought to engage state partners, technical experts, and pipeline operators in identifying pipeline risks and repairing, rehabilitating, and replacing the highest risk infrastructure. Additionally, the Call to Action called on pipeline operators and owners to review their pipelines and quickly repair and replace sections in poor condition.

This was a significant action by DOT. It also served as an acknowledgment that rulemakings alone were not sufficient to mitigate risks and it would require collaborative actions by regulators and operators to accelerate the repair, rehabilitation and replacement of the nation's aging pipelines. While current infrastructure replacement programs and regulations are making enhanced safety improvements, in the opinion of the DOT they just quite simply are not making the necessary improvements at a fast enough rate.

[11] Exhibit JSM-R-5 is a copy of the Call to Action.

Q. PLEASE CONTINUE.

A. In the Call to Action, Secretary LaHood provided additional information on the 2009 Final Rule, which as I discussed above created the DIMP regulations. Secretary LaHood stated that the DIMP regulations:

> "require[] operators of local gas distribution pipelines to evaluate the risks on their pipeline systems to determine their fitness for service and take action to address those risks. <u>For older gas distribution systems, the appropriate mitigation measures could involve major pipe rehabilitation, repair, and replacement programs.</u> At a minimum, these measures are needed to requalify those systems as being fit for service. <u>While these measures may be costly, they are necessary to address the threat to human life, property, and the environment.</u>
>
> In addition to the many pipelines constructed with obsolete materials, there are also early vintage steel pipelines in high consequence areas that may pose risks because of inferior materials, poor construction practices, lack of maintenance or inadequate risk assessments performed by operators. The lack of basic information or incomplete records about these systems is also a contributing factor. The U.S. DOT is seeking to make sure these risks are identified, the pipelines are assessed accurately, and preventative steps are taken where they are needed."

Q. DID SECRETARY LaHOOD'S CALL TO ACTION SPECIFICALLY ADDRESS THE STATES?

A. Yes, it did. Exhibit JSM-R-6 is a copy of Secretary LaHood's March 28, 2011 letter to State Governors, which stated among other things:

> "We appreciate your State's partnership on pipeline safety inspection and enforcement. In 2009, the Pipeline and Hazardous Materials Safety Administration provided the majority of the funding for your pipeline safety program, trained your State's inspectors alongside our own, and worked with them to enforce your State pipeline safety laws.
>
> Now, we want to partner with you again to ensure that all pipeline companies in your State, both public and private, are correctly analyzing the risk to their pipeline systems and using the appropriate

> assessment technologies. Your pipeline safety staff can help make this happen. <u>We ask you to urge your staff to encourage companies and the State utility commission to accelerate pipeline repair, rehabilitation, and replacement programs for systems whose integrity cannot be positively confirmed.</u> This is one of the best ways to help protect your citizens from accidents like those in Allentown, Marshall, and San Bruno."

VI. ATMOS ENERGY'S IMPLEMENTATION

Q. HAVE THE FEDERAL AND STATE PIPELINE SAFETY CHANGES DISCUSSED PREVIOUSLY IMPACTED THE WAY THAT NATURAL GAS COMPANIES MONITOR AND MANAGE THE SAFETY OF THEIR DISTRIBUTION SYSTEMS?

A. Absolutely. The federal changes and the Call to Action have resulted in an increasingly proactive approach to pipeline safety.

Q. HOW HAVE THE CHANGES SPECIFICALLY IMPACTED ATMOS ENERGY?

A. Atmos Energy has implemented a more proactive approach to pipeline safety. Atmos Energy's intention is not only to repair identified leaks but also to proactively identify pipes where the risks of leaks developing are unacceptably high and to then design and implement a plan to mitigate those risks. As a result, Atmos Energy must invest capital into our system at a much higher annual rate than we have historically done to address safety and integrity issues identified through the risk assessment process. Mr. Smith's direct and rebuttal testimony clearly demonstrates that Atmos Energy's replacement work in Kentucky has had a direct and positive effect on Kentucky's system.

As I have noted, the previously accepted approach to integrity management is no longer sufficient. Prudent integrity management now requires operators to more proactively identify and invest in risk control measures beyond minimum requirements. Atmos Energy's proactive capital investment in a regulatory environment with reduced regulatory lag is an example of such a proactive measure. Through its proactive and accelerated replacement work, Atmos Energy is better able to mitigate system risks rather than simply reacting once an accident has occurred.

Q. IS THERE ANY REASON FOR ATMOS ENERGY TO CONTINUE REPLACING PIPE IN KENTUCKY?

A. Absolutely. Going forward, we must continue to focus on maintaining and improving our safety and reliability record in a manner consistent with the approach to pipeline safety which demands our industry be proactive in identifying and mitigating risks, in the collective interest of improving safety and reliability. There is no room for complacency or error. In that vein, Atmos Energy's accelerated replacement of infrastructure is an example of reasonable actions taken to avoid future accidents.

VII. <u>CONCLUSION</u>

Q. WHY IS ATMOS ENERGY ASKING THE COMMISSION TO CONTINUE ITS ACCELERATED REPLACEMENT WORK AT THIS TIME?

A. Integrity programs were intended to drive pipeline operators to better understand the threats to and the condition of their assets in order to repair or replace the pipeline proactively. In that regard, where Atmos Energy determines increased risks on our system, we must be able to carefully monitor the issues, devote additional resources, and accelerate work when needed. This includes the removal of materials prone to leaks and potential failure. These steps are necessary to allow Atmos Energy to monitor and inspect its system and renew pipe when needed, rather than doing so in a crisis mode.

The natural gas industry is undergoing dramatic changes in the way we approach safety and reliability and reexamining the way we evaluate what is the appropriate balance of safety and cost. Today our customers are reaping the benefits of low-cost and plentiful natural gas. At the same time, we must face the reality that our infrastructure is aging and expectations about safety and reliability are being raised in light of recent tragic incidents that have led to fatalities, injuries, and property damage. Given these factors, this rate case provides the Commission with an excellent opportunity to continue regulatory treatment designed to fund our investment in the safety and reliability of our natural gas infrastructure. In my view, the evidence presented should lead the Commission to a finding in this case that Atmos Energy's continued replacement of infrastructure to promote safety and reliability is in the public interest.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

U.S. Department
of Transportation

**Pipeline and Hazardous
Materials Safety
Administration**

Administrator

1200 New Jersey Avenue SE
Washington, DC 20590

DEC 19 [illegible]

Mr. Tony Clark
Chairman of the Board and President
National Association of Regulatory Utility Commissioners
1101 Vermont Avenue, NW
Suite 200
Washington, DC 20005

Ms. Collette Honorable
Chair, NARUC Pipeline Safety Task Force
National Association of Regulatory Utility Commissioners
1101 Vermont Avenue, NW
Suite 200
Washington, DC 20005

Dear Mr. Clark and Ms. Honorable:

As U.S. Department of Transportation (DOT) and the National Association of Regulatory Utility Commissioners (NARUC) continue to support efforts to accelerate the repair, rehabilitation, and replacement of high-risk infrastructure in pipeline systems, we appreciate the NARUC's continued diligence in promoting rate mechanisms that will encourage and will enable pipeline operators to take reasonable measures to repair, rehabilitate or replace high-risk gas pipeline infrastructure. We have prepared, and attached, a white paper on state pipeline infrastructure replacement programs in the hope that you will share it with your members as a resource for encouraging more States to adopt alternative or more flexible rate mechanisms that will facilitate the replacement or repair of high-risk pipelines.

As you know, the Pipeline and Hazardous Materials Safety Administration (PHMSA) has regulatory authority in regard to the safety of our nation's pipelines. PHMSA, however, does not have the authority to determine the routing, rates, or other terms and conditions of service for gas pipelines. The Federal Energy Regulatory Commission makes these determinations for interstate gas pipelines, and the State public utility commissions you represent typically do the same for intrastate gas pipelines. Most State commissions are also responsible for oversight of intrastate pipeline safety through certifications or agreements with PHMSA.

Many State public utility commissions have encouraged the timely repair, rehabilitation, and replacement of high-risk gas pipeline infrastructure through special rate mechanisms. Some legislatures have also provided their State public utility commissions with specific statutory authority to approve such programs for intrastate gas lines. A comprehensive list of these programs is available at http://opsweb.phmsa.dot.gov/pipelineforum/pipeline-systems/state-pipeline-system/state-replacement-programs/.

We believe that the timely repair, rehabilitation, and replacement of high-risk gas pipeline infrastructure are critical to ensuring public safety. A series of recent gas pipeline accidents, including the September 9, 2010 San Bruno, California accident, the January 19, 2011 Philadelphia, Pennsylvania accident, and the February 10, 2011 accident, show the terrible loss of life and property that can occur without adequate attention to the integrity of pipeline infrastructure.

PHMSA believes that an effective program for ensuring the timely rehabilitation, repair, or replacement of high-risk gas pipelines might have helped prevent these accidents. Accordingly, we recommend that State public utility commissions consider accelerating work on the following kinds of high-risk intrastate gas infrastructure in the future:

- Cast iron gas mains, which can be prone to failure as a result of graphitization or brittleness;
- Plastic pipe manufactured in the 1960s to the early 1980s, which is susceptible to premature failures as a result of brittle-like cracking;
- Mechanical couplings used for joining and pressure sealing pipe, which are prone to failure under certain conditions;
- Bare steel pipe without adequate corrosion control (i.e., cathodic protection or coating);
- Copper piping;
- Older pipe, if it is vulnerable to failure from time-dependent forces, such as corrosion, stress corrosion cracking, settlement, or cyclic fatigue factor; and
- Pipelines with inadequate construction records or assessment results to verify their integrity.

PHMSA requests your support in ensuring that State commissions implement effective programs for the timely repair, replacement, and rehabilitation of high-risk gas pipeline infrastructure.

I look forward to continuing to work with the NARUC on pipeline safety and welcome any thoughts that you have on the issues discussed in this letter. Please send your response to Jeffrey Wiese, Associate Administrator for Pipeline Safety, or to contact me if you have any questions or concerns.

Regards,

Cynthia L. Quarterman

Enclosure: White Paper

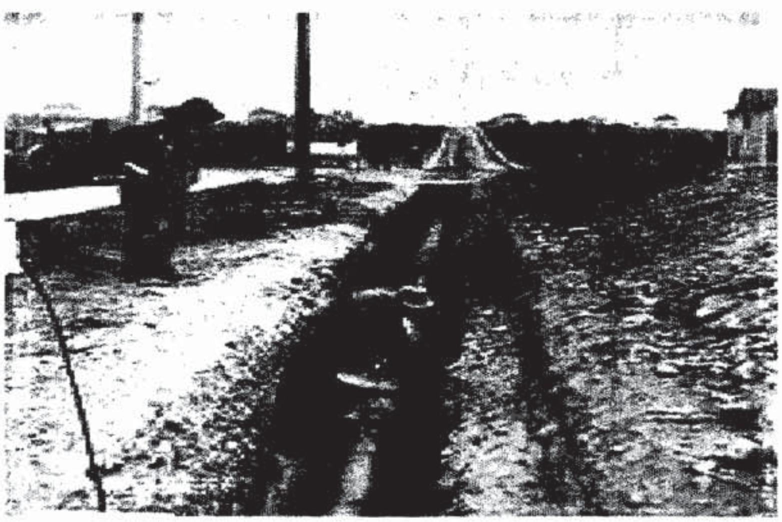
UNITED STATES DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

White Paper on State Pipeline Infrastructure Replacement Programs

Prepared for

National Association of Regulatory Commissioners

December 2011



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Introduction

Under the leadership of Transportation Secretary Ray LaHood and Administrator Cynthia Quarterman, the Pipeline and Hazardous Materials Safety Administration (PHMSA) has issued a Call to Action with the goal of accelerating the rehabilitation, repair, and replacement of high-risk pipeline infrastructure. This effort comes on the heels of several high profile pipeline accidents, including two recent gas distribution line explosions in Pennsylvania that resulted in multiple deaths.

As part of Secretary LaHood's Call to Action, PHMSA has prepared this white paper to urge State public utility commissions to expand the use of pipeline infrastructure replacement programs. It includes an overview of natural gas ratemaking, a discussion of the need to take prompt action to remediate high-risk pipeline infrastructure, and a description of the various State programs that are being used for that purpose.

Executive Summary

Public safety requires prompt action to repair, remediate, and replace high-risk gas pipeline infrastructure, including cast iron mains, certain vintages of plastic pipe and mechanical coupling installations, bare steel pipe without adequate corrosion control, and copper piping. Several recent gas pipeline accidents show the terrible consequences that can occur if such action is not taken.

The Federal Energy Regulatory Commission establishes rates for interstate natural gas pipeline service under the "just and reasonable" standard provided in the Natural Gas Act of 1938. State public utility commissions (and in some cases local authorities) establish rates for intrastate natural gas pipeline service. While based on State and local laws, those determinations are generally made on the basis of a formula that is similar to the "just and reasonable" standard.

Pipeline infrastructure replacement programs for gas distribution systems exist in nearly 30 States. Some State Public utility commissions have used their traditional ratemaking authority to approve these programs, the terms and conditions of which are established under a generally applicable statutory provision. Other State public utility commissions have specific authority to approve such programs. The terms, conditions, and cost recovery mechanisms of these programs vary by statute. Whether as part of the traditional ratemaking process or in a separate proceeding, PHMSA is encouraging the States to accelerate the remediation of high-risk gas pipeline infrastructure.

PHMSA intends to focus on this issue in implementing the new Gas Distribution Pipeline Integrity Management Program Rule and as part of the annual certification process for State pipeline safety programs. PHMSA is also willing to provide other assistance to State public utility commissions who are seeking to establish or improve programs for the repair, rehabilitation, and replacement of high-risk pipeline infrastructure.

I. General Ratemaking Principles

Federal Ratemaking

The Federal Energy Regulatory Commission (FERC) regulates the interstate sale and transportation of natural gas under the Natural Gas Act of 1938 (NGA). The NGA imposes a "just and reasonable" requirement on the rates charged for interstate pipeline services, a standard that requires FERC to consider both the interests of pipeline operators and ratepayers. FERC utilizes varying ratemaking methodologies to meet the "just and reasonable" standard, such as selective discounting, market-based rates, and negotiated rates. However, the underlying premise that ratemaking should be based on the cost of providing service remains a strong principle in rate-making proceedings. Accordingly, cost-of-service ratemaking is the primary method that FERC uses to establish rates.

Cost-of-service ratemaking bases rates on the cost of service and affords the pipeline a reasonable rate of return. The Cost-of-Service:

> Includes the product of the pipeline's Rate Base (which is the pipeline's investment) and the Overall Rate of Return, plus its Operation and Maintenance Expenses (O&M), Administrative and General Expenses (A&G), Depreciation Expense, Non-Income Taxes and Income Taxes, less Revenue Credits.

In this equation, the Rate Base captures the total amount invested in the pipeline and is used to calculate the permissible return on investment. The Overall Rate of Return is a product of the pipeline's capitalization ratio, the cost of debt, and the rate of return that is allowed on the pipeline's equity. Total cost-of-service captures the amount of rate revenue that a pipeline company must charge in order to maintain profitability and remain an attractive prospect for future investment.

FERC applies cost-of-service and other rate methodologies in rate proceedings to set initial rates for new or expanding pipelines, increase rates for existing pipelines, and require prospective changes to existing rates. Applications to establish new or expanded pipeline service must be approved by FERC and are required to meet a "public convenience and necessity" standard. In a certificate proceeding, FERC authorizes initial rates that remain in effect until a further rate proceeding is held. In a general Section 4 rate case, a pipeline files to increase rates and is required to prove that its proposal is "just and reasonable." Alternatively, in a Section 5 rate proceeding, FERC may require prospective rate changes, if it is determined that a pipeline's rates no longer meet the "just and reasonable" standard.[1]

State Ratemaking

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[1] Cost-of-Service Rates Manual, Federal Energy Regulatory Commission, June 1999.

State public utility commission (PUCs) regulate the intrastate sale of natural gas, which includes establishing rates for the end user. State PUCs evaluate ratemaking proposals according to a variety of legislative mandates, policy objectives, and consumer interests, but have traditionally set rates according to the "just and reasonable" standard. As articulated by the National Regulatory Research Institute, these rates share four general characteristics. First, rates are reflective of "an efficient or prudent utility" and, therefore, do not include those costs that a utility could eliminate without impairing efficiency or profitability. Second, rates incorporate the natural consequences of a utility's provision of service at different levels and to different classes of customers. Third, rates are set at a level that provides the utility with an acceptable return to ensure that it remains an attractive candidate for new capital investment. Lastly, the utility's provision of service should be nondiscriminatory. Within these general principles, the States use varying methods to establish rates, some of which are outlined below.

Rates for Investor-Owned Local Gas Distribution Companies

Local distribution companies are privately-owned utilities and are required to provide distribution of natural gas to any customer within its geographic franchise area upon reasonable request. These utilities own the natural gas being distributed for their "sales customers" and get paid a fee for the distribution service. Local distribution companies do not earn any money from the sale of the natural gas itself, whether the utility owns the natural gas or transports it on behalf of the customer. The companies simply pass the cost of the gas straight through to the customer. Customers who have purchased their natural gas from a third party supplier or market and wish the distribution company to transport the gas to their business or home, commonly referred to as "transportation customers," pay a fee for the transport of natural gas over the local distribution company's pipeline.

State PUCs regulate the rates, terms, and conditions of service for investor-owned natural gas distribution systems. Local agencies generally perform that regulatory function for publicly-owned distribution utilities. These State and local authorities are also responsible for ensuring that the operation of these utilities serves the public interest. In some cases, that may require prohibiting a utility from turning off a residential customer's gas service for nonpayment during cold weather, asking for safety-driven changes beyond those required by the Federal and State safety regulators, or requiring utilities to offer energy conservation programs.

Natural gas utilities are required to post the rates, terms, and other conditions of service with their State PUCs, and customers must pay the posted rates to obtain the applicable service. Utilities also have information on file with State PUCs on the current "purchased gas adjustment charge." These charges account for market-driven changes in the price the utility pays for the gas supplied to its customers.

Rates for Publicly-Owned Local Gas Utility Systems

Publicly-owned gas utility systems are non-profit enterprises that are owned by the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities. These utilities own the natural gas that is provided to their customers and charge a fee for the distribution service. Publicly-owned utilities also pass through and recover the cost of acquiring the natural gas that is distributed.

Unlike privately-owned pipeline systems, most State PUCs do not establish rates for publicly-owned gas distribution systems. That function is typically performed by a local body, like a city or county council or utility board. There is no requirement that the rate charged by the utility be based on the cost of service, and the utility may charge whatever rate is established by its governing body.

Rates for publicly-owned utilities do not include costs for return on investment or profit, and any necessary capital is raised by issuing bonds. Customers of municipal utilities pay the purchased gas adjustment charge for the amount of gas the utility distributes during the billing period. Rate changes must be approved by the city council or the utility board.

II. Need for Repair, Rehabilitation, and Replacement of High-Risk Gas Pipeline Infrastructure

The safety of natural gas distribution systems has improved significantly since the enactment of the Natural Gas Pipeline Safety Act of 1968, which provided DOT with the authority to establish safety standards for natural gas systems. A number of serious incidents in natural gas distribution systems, however, still occur each year, and many of those incidents are caused by failures of high-risk pipeline infrastructure. Thus, there is a need to improve pipeline safety by repairing, rehabilitating and replacing high risk pipe.

High-risk pipeline infrastructure is piping or equipment that is no longer fit for service. As discussed below, that lack of fitness can be the product of a variety of factors.

- Cast iron gas mains and service lines can be prone to failure as a result of graphitization or brittleness. The installation of cast iron pipe dates to the 1830s, and remained prevalent until the post-World War II period. Many major urban areas, including Philadelphia, PA; Boston, MA; Baltimore, MD; Washington, DC; Detroit, MI; Chicago, IL; and San Francisco, CA, still have cast iron pipe in their natural gas distribution systems.[2]

- Certain vintages of plastic pipe are susceptible to premature failures as a result of brittle-like cracking. In April 1998, the National Transportation Safety Board (NTSB) released a Special Investigation Report on Brittle-Like Cracking in Plastic Pipe for Gas Service. NTSB found that the long-term strength and resistance of plastic pipe to brittle-like cracking may have been overrated for much of the plastic pipe manufactured and installed from the 1960s through the early 1980s. The NTSB

[2] http://opsweb.phmsa.dot.gov/pipelineforum/reports-and-research/cast-iron-pipeline/

also found that any potential public safety hazards from these failures are likely to be limited to locations where stress intensification exists. In response to the NTSB report and subsequent investigations, PHMSA issued four advisory bulletins on the susceptibility of certain kinds of older plastic pipe to brittle-like cracking.[3]

- Mechanical coupling installations are devices that are used for the joining and pressure sealing of two pieces of pipe. These devices are prone to failure under certain conditions. In March 2008, PHMSA issued an Advisory Bulletin (ADB) on the use of mechanical couplings in natural gas distribution systems. The ADB noted that these devices are more likely to fail when there is inadequate restraint for the potential stresses on the two pipes, when the couplings are incorrectly installed or supported, or when components experience age-related deterioration. The ADB also noted that inadequate leak surveys can fail to detect a coupling in need of repair and lead to more serious incidents.[4]

- Pipelines lacking adequate construction records or assessment results to verify their integrity. In January 2011, PHMSA issued an ADB on the need to use traceable, verifiable, and complete records in establishing the maximum allowable operating pressures and developing and implementing integrity management programs for natural gas pipelines. The ADB responded to an NTSB recommendation, which resulted from its investigation of the September 2010 intrastate natural gas transmission line rupture in San Bruno, California, which is discussed below.

- Other kinds of pipe installations, including bare steel pipe without adequate corrosion control (i.e., cathodic protection or coating) and copper piping, are also more susceptible to failure.

- Age of pipe should be considered in determining whether pipeline infrastructure is vulnerable to failure from time-dependent forces, like corrosion, stress corrosion cracking, settlement, or cyclic fatigue.

Several recent gas pipeline accidents show the grave consequences that can occur if high-risk gas pipeline infrastructure is not properly repaired, rehabilitated, or replaced. For example,

- On September 9, 2010, an intrastate natural gas transmission line ruptured in San Bruno, California. The ensuing explosion and fire resulted in 8 fatalities, multiple injuries, and destroyed 38 homes. NTSB has released a final report on the cause of the accident and concluded that the failure was the result of an improperly-welded section of pipe that had been installed in 1956 and never subjected to hydrostatic pressure testing.

[3] 72 FR 51301.

[4] 73 FR 11695.

- On January 19, 2011, a natural gas explosion and fire in a natural gas distribution system killed one person and injured five others in Philadelphia, Pennsylvania. The cause of the accident remains under investigation, but preliminary reports indicate that the source of the gas leak was a 12-inch cast iron gas main installed in the 1920s.

- On February 10, 2011, another natural gas explosion and fire in a natural gas distribution system killed five people and destroyed several homes in Allentown, Pennsylvania. The cause of the accident remains under investigation, but preliminary reports indicate that the source of the gas leak was an 83-year-old, 12-inch cast iron gas main.

Recognizing that prompt action to replace these high-risk gas pipelines might have prevented each of these accidents, Transportation Secretary Ray LaHood issued a Call to Action in April 2009 encouraging the States to expand and accelerate the use of such programs.[5] Twenty-two States responded to the Secretary's initiative by providing PHMSA with information on their efforts to remediate high-risk pipeline infrastructure.

After reviewing that information and performing additional research, PHMSA decided to prepare the following overview of the State pipeline infrastructure replacement programs. PHMSA urges the appropriate regulatory authorities will use this information to accelerate their efforts to repair, rehabilitate, and replace high-risk gas pipeline infrastructure in their jurisdictions. In addition to the analysis provided below, a comprehensive list of all of these programs is included in Appendix I.

III. Using Traditional Ratemaking Authority to Establish Infrastructure Replacement Programs

Several state public utility commissions have used their traditional ratemaking authority to approve pipeline infrastructure replacement programs. The examples discussed below show how that authority can be used to ensure the timely repair, rehabilitation, and replacement of high-risk pipeline infrastructure without additional legislation.

New Jersey

Originally established in 1911 as the Department of Public Utilities, the mission of the New Jersey Board of Public Utilities (BPU) is "[t]o ensure the provision of safe, adequate and proper utility and regulated service at reasonable rates, while enhancing the quality of life for the citizens of New Jersey and performing these public duties with integrity, responsiveness and efficiency."[6] The Division of Energy is responsible for regulating the State's four natural gas

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[5] http://opsweb.phmsa.dot.gov/pipelineforum/

[6] http://www.nj.gov/bpu/about/index.html.

service providers: Elizabethtown Gas, New Jersey Natural Gas (NJNG), PSE&G, and South Jersey Gas.[7]

As part of then-Governor Jon Corzine's economic stimulus plan, BPU approved accelerated pipeline infrastructure replacement programs using its plenary authority to require or enable natural gas companies to provide safe, adequate, and proper service to its customer.[8] In a December 22, 2009 provisional order, BPU approved Elizabethtown Gas's petition to implement a Utility Enhancement Infrastructure Rider (i.e., a rate increase to allow for an accelerated recovery of the costs associated with performing certain gas-distribution infrastructure related projects). The list of qualifying projects included the replacement of 29 miles of 10- and 12-inch and 41.9 miles of 4-inch cast iron gas mains; the installation of 6 miles of 8-inch main and 20 miles of 12-inch main in certain locations. In a subsequent filing, Elizabethtown petitioned BPU to approve an additional rate increase to cover greater-than-anticipated costs for each of these projects.[9]

Likewise, in an April 29, 2009 order, BPU approved NJNG's petition to implement an Accelerated Infrastructure Investment Program (AIIP), i.e., a rate increase to allow for an accelerated recovery of the costs associated with performing 14 infrastructure projects. In a March 30, 2011, BPU approved NJNG's petition to add 9 additional projects to the AIIP. The total anticipated cost for these projects is approximately 130 million dollars.[10]

Kentucky

Created in 1934, the Kentucky Public Service Commission (KPSC) is a three member administrative body with authority to regulate investor-owned natural gas companies. KPSC does not regulate natural gas utilities subject to the control of cities or political subdivisions, or those served by the Tennessee Valley Authority.[11]

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[7] http://www.state.nj.us/bpu/index.shtml

[8] Specifically, § 48: 2-23 states:

The board may, after public hearing, upon notice, by order in writing, require any public utility to furnish safe, adequate and proper service, including furnishing and performance of service in a manner that tends to conserve and preserve the quality of the environment and prevent the pollution of the waters, land and air of this State, and including furnishing and performance of service in a manner which preserves and protects the water quality of a public water supply, and to maintain its property and equipment in such condition as to enable it to do so.

The board may, pending any such proceeding, require any public utility to continue to furnish service and to maintain its property and equipment in such condition as to enable it to do so.

[9] *See* http://www.elizabethtowngas.com/Universal/RatesandTariff/RegulatoryInformation.aspx

[10] *See* http://www.njng.com/regulatory/filings.asp

[11] http://psc.ky.gov/

In a January 31, 2002 order, KPSC approved a petition filed by Duke Energy Kentucky, Inc. (Duke) for approval of an Accelerated Main Replacement Program (AMRP) Rider, which was designed to allow Duke to reduce the time for replacing its cast iron and bare steel mains from 15 years to 10 years. The Kentucky Attorney General appealed that order, arguing that KPSC lacked the authority to approve such a program outside of the confines of a general rate case. The Kentucky Supreme Court later ruled that KPSC had the power to approve the AMRP Rider under its plenary authority to ensure that rates are "fair, just and reasonable."[12]

Indiana

Established in the early 20th century, the Indiana Regulatory Utility Commission (IRUC) is comprised of five Commissioners who are appointed by the Governor to staggered four-year terms. The Gas Division is responsible for regulating the rates and terms and conditions of service for intrastate gas utilities.[13]

IRUC uses a deferred accounting alternative to allow eligible infrastructure investment costs to be diverted to a special deferred account. In the next rate case, the costs are amortized, recovered in rates, and the balance in the special deferred account is either reduced or eliminated. Gas utilities must establish, through the ratemaking proceeding, that all infrastructure investment costs in such accounts are properly accounted for. The assets in these deferred accounts may accrue interest, which isamortized and recoverable. The amount and type of infrastructure costs may be limited and are subject to state approval.

IRUC has approved Vectren Corporation's program to target 90 miles of pipeline replacements per year, as part of a broader, 20-year effort to replace 1,700 miles of aging bare steel and cast iron mains in Indiana and Ohio.[14]

IV. Using Specific Ratemaking Authority to Establish Infrastructure Replacement Programs

Several states have provided their public utility commissions with specific statutory authority to approve pipeline infrastructure replacement programs. Some states, like Missouri, Kansas, and Nebraska, have enacted statutes with detailed eligibility requirements and cost-recovery formulas. Other states, like Ohio, have adopted statutes that provide their commissions with far more flexibility and discretion. Still other states, like Texas and Virginia, fall somewhere in between.

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[12] *Kentucky Public Service Commission v. Commonwealth of Kentucky*, 324 S.W.3d 373 (KY 2010).

[13] http://www.in.gov/iurc/

[14] *http://www.enengineering.com/pdf/p&gj4_05.pdf.*

Infrastructure Replacement Surcharge: Missouri, Kansas, and Nebraska

Missouri, Kansas, and Nebraska have adopted statutes that authorize the approval of infrastructure replacement surcharges. Local distribution companies are allowed to charge current customers for the cost of replacing existing infrastructure through the performance of certain projects. A specific formula is provided for determining the permissible amount of the surcharge; procedural requirements are also included to facilitate commission review and approval.

Missouri and Kansas

Established in 1913, the Missouri Public Service Commission (MPSC) regulates local gas distribution companies and is composed of five commissioners who are appointed by the governor.[15] Founded two decades later, the Kansas Corporation Commission (KCC) regulates natural gas companies and is composed of three commissioners who are appointed by the Governor for 4-year terms with the approval of the Senate.[16]

On July 9, 2003, the Missouri General Assembly enacted a statute allowing gas corporations to petition MPSC for approval of an infrastructure system replacement surcharge (ISRS) as of August 28, 2003. Using Missouri's ISRS statute as a model, the Kansas Legislature enacted the Gas Safety and Reliability Act (GSRA) three years later, on April 12, 2006. The GSRA provided that as of July 1, 2006, a natural gas public utility could petition the KCC to establish or change gas system reliability surcharge (GSRS) rate schedules.

These two statutes are similar in many respects and include provisions that define the kinds of gas utility projects which are eligible for a cost recovery surcharge, establish a formula for determining and limiting the amount of that surcharge, and prescribe the procedural requirements that must be met before a surcharge can be imposed.

Both statutes generally limit eligible infrastructure system replacements to gas utility plant projects that:

- Do not increase revenues by directly connecting the infrastructure replacement to new customers;
- Are in service and used and useful;
- Were not included in the gas corporation's rate base in its most recent general rate case; and
- Replace, or extend the useful life of an existing infrastructure.

The statutes also list the kinds of "gas utility plant projects" that are eligible for the surcharge:

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[15] http://psc.mo.gov/

[16] http://www.kcc.state.ks.us/index.htm

- Mains, valves, service lines, regulator stations, vaults, and other pipeline system components installed to comply with State or Federal safety requirements as replacements for existing facilities that are in deteriorated condition;

- Main relining projects, service line insertion projects, joint encapsulation projects, and other similar projects extending the useful life, or enhancing the integrity of pipeline system components for compliance with State or Federal safety requirements; and

- Facility relocations as a result of construction or improvement of a highway, road, street, public way, or other public work by or on behalf of the United States, the State (or political subdivision thereof), or another entity having the power of eminent domain provided that the costs related to such projects have not been reimbursed to the gas corporation.

The two statutes also prescribe a formula for determining the maximum amount and duration of the surcharge:

- MPSC and KCC cannot approve a surcharge that produces a total annualized surcharge revenue below the lesser of $1,000,000 or 1/2 percent of the gas company's base revenue level or exceeds 10 percent of the base revenue approved at the gas company's most recent general rate proceeding.

- A surcharge cannot be approved for a gas company that has not had a general rate proceeding decided or dismissed within a certain number of months (the past 36 months for Missouri and the past 60 months for Kansas), unless the gas company has filed for one or is the subject of a new proceeding.[17]

Finally, there are also procedural requirements that must be met to authorize the surcharge:

- Gas companies that petition MPSC or KCC for a surcharge must submit a proposed ISRS or GSRS and supporting documentation.

- MPSC and KCC must publish notice of that filing, and their respective staffs are required to confirm underlying costs and submit a report within 60 days.

- MPSC and KCC may hold a hearing on the petition but must issue an order that is effective no later than 120 days after the filing.

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[17] As originally enacted, the GSRA prohibited a utility from collecting a GSRS for any period exceeding 60 months unless a filing had been made or was subject to a new proceeding. However, on April 13, 2011, the Kansas Legislature amended the GSRA to allow the KCC, on motion from a natural gas public utility, to extend that 60-month deadline for up to 12 months.

- A gas company cannot effectuate a change in its rates more often than twice every 12 months.

Nebraska

The Nebraska Public Service Commission (NPSC) regulates the rates and quality of service for investor-owned natural gas public utilities and is composed of five elected commissioners who serve 6-year terms.[18] On August 30, 2009, the Nebraska legislature enacted a statute allowing a jurisdictional utility to file an application and proposed rate schedule with NPSC to establish or change "infrastructure system replacement cost recovery charge rate schedules." Through this process, utilities may request an adjustment of their rates to recover costs for eligible infrastructure system replacements. Nebraska's legislation is largely bifurcated: utilities are treated differently depending on whether or not their prior rate filings were subject to negotiation.

NPSC is specifically disallowed from approving rate schedules that produce total annualized infrastructure system cost recovery charge revenue either:

- Below the lesser of one million dollars or one-half percent of the utility's base revenue level, as approved by the commission in the most recent general rate proceeding; or

- Exceeding ten percent of the utility's base revenue level, as approved by the commission in the most recent general rate proceeding.

Furthermore, NPSC cannot approve any rate schedules for a utility that has not had a general rate proceeding decided or dismissed by order within the 60 months immediately preceding the application for a infrastructure system replacement cost recovery charge. Utilities cannot collect a recovery rate for a period exceeding 60 months after the initial approval, unless that utility has filed for or is the subject of a new general rate proceeding within the 60-month period. (The rate may be collected until the effective date of a new rate schedule established as a result of a new general rate proceeding or until the rate proceeding is otherwise decided or dismissed by issuance of a commission order without new rates being established).

Two processes exist for establishing or changing a rate schedule. If the utility's last general rate filing was not subject to negotiation, the utility must submit to NPSC:

- A list of eligible projects;

- A description of the projects;

- The location of the projects;

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[18] http://www.psc.state.ne.us/index.htm

- The purpose of the projects;
- The dates construction began and ended;
- The total expenses for each project at completion; and
- The extent to which such expenses are eligible for inclusion in the calculation of the infrastructure system replacement cost recovery charge.

After the public advocate conducts an examination of this information to verify the underlying costs, NPSC must require a report on this examination to be prepared and filed not later than 60 days after the application. NPSC must hold a hearing on the application and issue an order that is effective not later than 120 days after the application is filed (there is a good-cause 30-day extension). If NPSC finds that an application complies with the applicable requirements, an order is issued authorizing the utility to recover appropriate pretax revenue. Utilities may apply for a change in any infrastructure system replacement cost no more than once in any 12-month period.

If a utility's last general rate filing was subject to negotiation, it must submit to NPSC the schedules, supporting documentation, and a written notice for each city that will be affected by the charge. The notice must identify the cities that will be affected by the filing and copies must be provided to each such city. Affected cities have 30 days from that filing to adopt a resolution of intent to negotiate a charge rate with the utility. A copy of the resolution in support, or a resolution of rejection, of the offer to negotiate must be provided to the utility and NPSC within seven days of adoption.

If NPSC receives timely resolutions from cities that represent more than 50 percent of the ratepayers within the affected cities, to negotiate a recovery rate with the utility, the commission will certify the case for negotiation and will take no action until the negotiation period has expired. If agreement is reached, it must be put in writing and filed with the commission, which then must enter an order either approving or rejecting the rate within 30 days of the filing of the agreement. If agreement is not reached, the affected cities and the utility must submit all documentation within 14 days after the commission receives notice that the negotiations have failed. A hearing must be held not later than 35 days after the receipt of this report. If the commission receives resolutions from cities representing more than 50 percent of ratepayers that expressly reject negotiations, the rate review proceeds immediately.

Interim Rate Adjustment: Texas and Virginia

<u>Texas</u>

Established in 1891, the Texas Railroad Commission (TRC) has primary regulatory authority over various aspects of the oil and natural gas industry. The Gas Services Division regulates the day-to-day activities of approximately 200 natural gas utilities and is responsible for ensuring that a continuous, safe supply of natural gas is available to local consumers at the lowest, reasonable price. TRC has exclusive authority over the rates and terms of service for gas utilities in unincorporated areas and original jurisdiction over utilities at a city gate. TRC is composed of three members who are elected to serve 6-year terms.[19]

On May 16, 2003, the Texas Legislature enacted the Gas Reliability Infrastructure Program (GRIP) statute, which allows gas utilities to recover a return on capital expenditures made during the interim period between general rate cases.[20] Specifically, a gas utility may file a tariff or rate schedule with TRC providing for an interim rate adjustment within two years of the utility's last general rate case. That tariff or rate schedule must be filed at least 60 days before the proposed implementation date of the new rates. During that 60-day period, implementation of the new rates may be suspended by the TRC or an affected municipality for up to 45 days.

The allowable amount of the interim rate adjustment is based on values associated with the utility's return on investment, depreciation expenses, ad valorem taxes, revenue-related taxes, and incremental federal income taxes. The reasonableness and prudence of the investments recovered by an interim rate adjustment is subject to review in the utility's next general rate case. Until the TRC issues a final order approving the interim rate adjustment in that rate case, all amounts collected under the tariff or rate schedule before the filing of that rate case are subject to refund (including with interest, if appropriate). Any utility that implements an interim rate adjustment is required to file a general rate case no later than 180 days after the fifth anniversary of the date its interim rate became effective. The regulatory authority itself may also initiate a rate case at any time to review the reasonableness of the utility's rates.

It should also be noted that TRC has issued regulations mandating the removal, rehabilitation, or replacement of gas distribution pipeline facilities as part of their state pipeline safety program.[21] That includes requirements for the removal of compression couplings and, more recently, for the submission of a written risk-based program, by August 1, 2011, for the removal or replacement of all other distribution facilities.

Virginia

Established in 1902, the Virginia State Corporation Commission (VSCC) is composed of three commissioners who are elected by the General Assembly for 6-year terms. Its Division of Energy Regulation is responsible for providing assistance in regulating investor-owned natural gas utilities.[22]

On April 11, 2010, the SAVE Act (Steps to Advance Virginia's Energy Plan) was enacted, authorizing certain natural gas utilities to petition the State Corporation Commission

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[19] http://www.rrc.state.tx.us/

[20] Tex. Util.Code Ann. § 104.301.

[21] http://info.sos.state.tx.us/pls/pub/readtac$ext.ViewTAC?tac_view=5&ti=16&pt=1&ch=8&sch=C&rl=Y

[22] http://www.scc.virginia.gov/pue/index.aspx

(SCC) for a separate rider ("SAVE rider"), allowing for the recovery of certain costs associated with eligible infrastructure replacement projects. While utilities are still required to apply for the SAVE rider, the statute places restrictions on the VSCC approval process, ostensibly to wall off this process from traditional ratemaking.

Under the Act, an eligible "natural gas utility" is any investor-owned public service company that furnishes natural gas service to the public. Natural gas utilities may apply for "eligible infrastructure replacement" projects that:

- Enhance safety or reliability by reducing system integrity risks associated with customer outages, corrosion, equipment failures, material failures, natural forces, or other outside force damage;
- Do not increase revenues by directly connecting the infrastructure replacement to new customers;
- Reduce or have the potential to avoid greenhouse gas emissions; and
- Are not included in the natural gas utility's rate base in its most recent rate case or in the rate base filed with a performance based regulation plan.

Specifically, eligible "natural gas utility facility replacement projects" are intended to replace storage, peak shaving, transmission or distribution facilities used in the delivery of natural gas, or supplemental or substitute forms of gas sources by a natural gas utility. The act specifically delineates recoverable costs, including return on investment, depreciation, property taxes, and carrying costs of the eligible infrastructure replacement projects.

In order to qualify for the SAVE rider, utilities must file a petition with VSCC to establish a plan, which must include a completion timeline, a schedule of cost recovery, and a certification that the plan is "prudent and reasonable." Prior to approval, VSCC must provide notice and an opportunity for a hearing on the plan. SAVE plans must be approved or denied within 180 days; in the case of a denial, VSCC must specifically detail the reasons for the denial and the utility may refile, without prejudice, an amended plan within 60 days, at which point the Commission has an additional 60 days to approve or deny. VSCC is specifically prohibited from requiring the filing of rate case schedules in conjunction with the consideration of a SAVE plan. In addition, no other revenue requirement or ratemaking issues may be examined in conjunction with the consideration of an application filed pursuant to the SAVE Act.

At the end of each 12-month period that a SAVE rider is in effect, the utility must reconcile the difference between the eligible replacement costs and the amounts recovered under the SAVE rider. This reconciliation provides the basis for an adjustment to the SAVE rider, which VSCC must approve or deny within 90 days, whether it is an additional recovery or a refund. Finally, the Act states that this rider is in addition to all other costs that a utility is permitted to recover and cannot be considered as an offset to other VSCC-approved cost of service or revenue requirements. In addition, the rider cannot be included in the computation of a performance based regulation plan revenue-sharing mechanism.

In summary, the Virginia SAVE Act:

- Uses a rider for the recovery of certain eligible infrastructure costs;
- Uses a statutorily prescribed process that is separated from the ratemaking process;
- Includes an amendment process to incorporate increased project costs, but also requires refunds;
- Requires approval or denial within specific timeframe; and
- Restricts VSCC from considering any costs that the utilities are already allowed to recover in the consideration of whether a utility should be able to recover infrastructure costs.

Alternative Rate Plan: Ohio

Established in 1913, the Public Utilities Commission of Ohio (PUCO) regulates various public utilities in Ohio, including more than two dozen natural gas companies. Those companies provide gas service to more than 3 million users and operate a network of approximately 54,000 miles of regulated distribution lines. PUCO is composed of 5 commissioners who are appointed by the Governor for 5 year terms.[23]

Ohio Chapter 4901: 1-19 governs the filing and consideration of an alternative rate case by a natural gas company. Alternative rate plans may include automatic adjustments based on a specified index or changes in a specified cost. In its "alternative rate plan filing," the applicant must notify the commission and the consumer services department of its intent to file at least 30 days prior to the expected date of filing. The application (sample is included in rule appendix) must include the proposed rates, a summary of the proposed plan, a comparison of the typical "before" and "after" customer bill, and any waiver requests. In addition, the applicant must fully justify any proposal to deviate from the traditional rate of return regulation, including the rationale for the alternative plan, including "how it better matches actual experience of performance of the company in terms of costs and quality of service to its regulated customers."

PUCO may grant alternative rate regulation on the basis of this application. However, PUCO may subsequently determine that the natural gas company is not in substantial compliance with state policy, or on the motion of an adversely affected party, abrogate any order when (1) the commission determines that the findings are no longer valid and that modification or abrogation is in the public interest; and (2) the modification or abrogation is not made more than eight years after the effective date of the order, unless the affected natural gas company consents.

California

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[23] http://www.puco.ohio.gov/puco/

The California Public Utilities Commission (CPUC) is responsible for regulating intrastate natural gas pipelines in the State of California, except for municipal gas systems.[24] CPUC is composed of five commissioners who are appointed by the Governor.

On October 7, 2011, the Governor approved a package of pipeline safety bills with several new mandates for gas pipeline operators and CPUC. The relevant provisions include:

- Requiring operators of intrastate gas transmission lines to prepare and submit to CPUC a plan for pressure testing each line segment and to replace each segment that is not tested. Plans must include a timeline for completing all testing and replacements as soon as practicable with interim safety measures during implementation. Where warranted, segments must also be capable of accommodating inline inspection devices.

- Requiring gas pipeline operators to submit to CPUC for approval a plan for the safe and reliable operation of their gas pipeline facilities. Plans must be consistent with Federal pipeline safety laws and must address specific criteria, including: minimizing hazards and systemic risks; identifying safety-related systems that may be deployed; patrolling and inspecting for leaks; responding to reports of leaks; determining MAOP; ensuring qualified and adequately-sized workforce; and meeting applicable pipeline safety standards.

- Requiring gas pipeline operators to report to CPUC twice per year on the strategic planning and decisionmaking approach that is used to determine and rank pipeline safety, integrity, reliability, operations and maintenance activities, and inspections.

- Establishing that is the policy of the State and CPUC for each gas pipeline operator to place safety as its top priority. CPUC must take reasonable and appropriate action to carry out this policy, including through ratemaking.

- Requiring gas pipeline operators who recover expenses for integrity management program and related pipeline maintenance and repairs to have a balancing account, with any unspent money being returned to ratepayers at the end of each rate cycle.

In a June 2011 order, CPUC had previously used its general authority to require operators of intrastate natural gas transmission lines to submit comprehensive pressure testing implementation plans. The purpose of these plans is to achieve the orderly and cost effective replacement or testing of all natural gas transmission lines in the State. The plans permit the use of alternatives that achieve the same standard of safety, but must include a prioritized schedule based on risk assessment and maintaining service reliability, as well as cost estimates with proposed ratemaking. The plans also address the retrofitting of pipelines to accommodate the use of in-line inspection tools and, where appropriate, automated or remotely controlled shut off valves.

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[24] CA PUB UTIL §§ 2101 *et seq.*, 4351-61, 4451-64.

V. CONCLUSIONS

Nearly 30 State public utility commissions have established pipeline infrastructure replacement programs as part of the ratemaking process. These programs play a vital role in protecting the public by ensuring the prompt rehabilitation, repair, or replacement of high-risk gas distribution infrastructure.

Several state public utility commissions, including those in New Jersey, Kentucky, and Indiana, have used their traditional ratemaking authority to approve such programs. Other States, like Missouri, Kansas, and Nebraska, have provided their public utility commissions with specific statutory authority to approve pipeline infrastructure replacement programs based on detailed eligibility requirements and cost-recovery formulas. Ohio has a statute in place that provides its commission with far more flexibility and discretion. California recently enacted a statutory scheme requiring the implementation of a comprehensive program for pressure testing and replacement of gas pipelines.

Whether as part of the traditional ratemaking process or in a separate proceeding, PHMSA urges State public utility commissions to accelerate the repair, rehabilitation, and replacement of high-risk pipeline infrastructure. The recent pipeline accidents in San Bruno, Philadelphia, and Allentown show the tremendous cost in terms of fatalities, injuries, and property damage that can result in the absence of such action.

PHMSA is focused on this issue in implementing its integrity management requirements for natural gas transmission and distribution lines and as part of the state certification process. PHMSA is willing to provide assistance to State public utility commissions who are seeking to establish or improve programs for the repair, rehabilitation, and replacement of high risk pipeline infrastructure. Such assistance could include offering testimony at legislative hearings or in state proceedings, providing technical expertise in identifying high-risk pipeline infrastructure, and ensuring that state pipeline safety regulators are effectively implementing the integrity management requirements for natural gas transmission and distribution lines.

Appendix I:

Additional Information on State Pipeline Infrastructure Replacement Programs

Hyperlinks Confirmed as of Date of Publication and Available for Use in Electronic Version Only

Alabama

STATE AUTHORITY: Alabama Public Service Commission

PROGRAM: Rate Stabilization and Equalization Plan

PARTICIPANTS: Mobile Gas

Alabama Gas

Arkansas

STATE AUTHORITY: Arkansas Public Service Commission

PROGRAM: Main Replacement Program Rider

PARTICIPANTS: CenterPoint Energy

California

STATE AUTHORITY: California Public Utilities Commission

PROGRAM: Comprehensive Implementation Plan

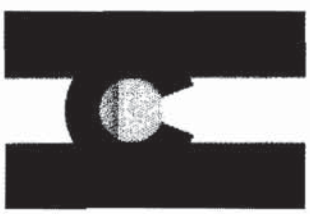
PARTICIPANT: San Diego Gas and Electric

PROGRAM: Pipeline Safety Enhancement Plan

PARTICIPANTS: Southern California Gas

Pacific Gas & Electric

Colorado



STATE AUTHORITY: Colorado Public Service Commission

PROGRAM: Pending

PARTICIPANT: Colorado Public Service Company

District of Columbia

STATE AUTHORITY: District of Columbia Public Service Commission

PROGRAM: Pending

PARTICIPANT: Washington Gas

Georgia

STATE AUTHORITY: Georgia Public Service Commission

PROGRAM: Pipeline Replacement Program

PARTICIPANT: Atlanta Gas Light

PROGRAM: Pipeline Replacement Surcharge

PARTICIPANT: Atmos Energy

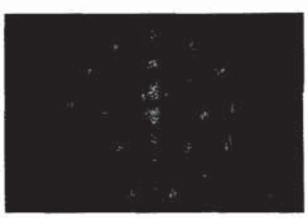
Illinois

STATE AUTHORITY: Illinois Commerce Commission

PROGRAM: Infrastructure Cost Recovery Rider

PARTICIPANT: Integrys Peoples Gas

Indiana



STATE AUTHORITY: Indiana Utility Regulatory Commission, Gas Division

PROGRAM: Pipeline Safety Adjustment

PARTICIPANT: Vectren Energy Delivery of Indiana, Inc.

Vectren South – SICEGO

Kansas

STATE AUTHORITY: Kansas Corporation Commission

PROGRAM: Accelerated Pipeline Replacement Rider

PARTICIPANT: Black Hills Energy

PROGRAM: Gas System Reliability Surcharge Rider

PARTICIPANT: Kansas Gas Service

Atmos Energy

LAWS: Gas Safety and Reliability Policy Act

Kentucky

STATE AUTHORITY: Kentucky Public Service Commission

PROGRAM: Accelerated Main Replacement Program Rider

PARTICIPANT: Columbia Gas Kentucky

PROGRAM: Pipeline Replacement Program

PARTICIPANT: Delta Natural Gas

PROGRAM: Accelerated Main Replacement Program

PARTICIPANT: Duke Energy Kentucky

PROGRAM: Pipeline Replacement Program Rider

PARTICIPANT: Atmos Energy

LAWS: KRS 278.509

Louisiana

STATE AUTHORITY: Louisiana Public Service Commission

PROGRAM: Rate Stabilization Tariffs

PARTICIPANTS: Atmos Energy – LA

Entergy

CenterPoint Energy

Maryland

STATE AUTHORITY: Maryland Public Service Commission

PROGRAM: Pending

PARTICIPANTS: Washington Gas

Massachusetts

STATE AUTHORITY: Massachusetts Department of Public Utilities, Pipeline Engineering and Safety Division

PROGRAM: Targeted Infrastructure Reinvestment Factor

PARTICIPANTS: Columbia Gas Massachusetts

National Grid Massachusetts

New England Gas

PROGRAM: Pending

PARTICIPATNT: Fitchburg Gas and Electric

Michigan

STATE AUTHORITY: Michigan Public Service Commission

PROGRAM: Main Replacement Program Rider

PARTICIPANT: SEMCO Energy

Mississippi

STATE AUTHORITY: Mississippi Public Service Commission

PROGRAM: Rate Stabilization Tariffs

PARTICIPANTS: Atmos Energy – MS

CenterPoint Energy

Missouri

STATE AUTHORITY: Missouri Public Service Commission

PROGRAM: Infrastructure System Replacement Surcharge

PARTICIPANTS: Ameren Missouri

Laclede Gas

Missouri Gas Energy

Atmos Energy - MO

LAWS: MO ST 393.1009 *et seq.*

Nebraska

STATE AUTHORITY: Nebraska Public Service Commission

PROGRAM: Infrastructure System Replacement Cost Recovery Charge

PARTICIPANT: Black Hills Energy

LAWS: NE ST 66-1865

NE ST 66-1866

NE ST 66-1867

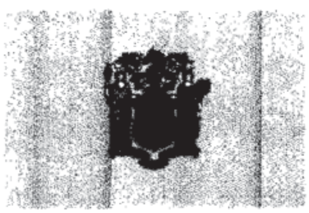
New Hampshire

STATE AUTHORITY: New Hampshire Public Utilities Commission

PROGRAM: Cast Iron Bare Steel Replacement Program

PARTICIPANT: National Grid Energy North

New Jersey



STATE AUTHORITY: New Jersey Board of Public Utilities

PROGRAM: Utility Enhancement Infrastructure Rider

PARTICIPANT: Elizabethtown Gas

PROGRAM: Accelerated Infrastructure Investment Program

PARTICIPANT: New Jersey Natural Gas

PROGRAM: Capital Adjustment Charge

PARTICIPANT: Public Service Electric and Gas

PROGRAM: Capital Investment Recovery Tracker

PARTICIPANT: South Jersey Gas

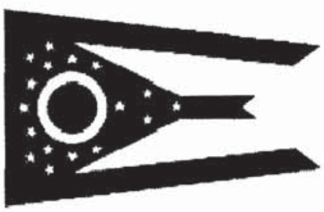
New York

STATE AUTHORITY: New York State Public Service Commission

PROGRAM: LIMITED INFRASTRUCTURE REPLACEMENT

PARTICIPANTS: National Grid Long Island, Niagara Mohawk, and NYC
Corning Natural Gas

Ohio



STATE AUTHORITY: Ohio Public Utility Commission

PROGRAM: Infrastructure Replacement Program

PARTICIPANTS: Columbia Gas Ohio

PROGRAM: Pipeline Infrastructure Replacement Cost Recovery Charge

PARTICIPANT: Dominion East Ohio

PROGRAM: Accelerated Main Replacement Program Rider

PARTICIPANT: Duke Energy Ohio

PROGRAM: Distribution Replacement Rider

PARTICIPANT: Vectren Energy Delivery of Ohio, Inc.

Oklahoma

STATE AUTHORITY: Oklahoma Corporation Commission

PROGRAM: Rate Stabilization Tariffs

PARTICIPANTS: Oklahoma Natural Gas

CenterPoint Energy

Oregon

STATE AUTHORITY: Oregon Public Utility Commission

PROGRAM: Replacement Projects

PARTICIPANT: Avista Corp

Rhode Island

STATE AUTHORITY: Rhode Island Public Utilities Commission

PROGRAM: Capital Expenditure Tracker Factor, Accelerated Replacement Program

PARTICIPANT: National Grid Narragansett Gas

South Carolina

STATE AUTHORITY: South Carolina Office of Regulatory Staff

PROGRAM: Rate Stabilization Tariff

PARTICIPANTS: Piedmont Natural Gas

South Carolina Electric and Gas

Texas

STATE AUTHORITY: Texas Railroad Commission

PROGRAM: Gas Reliability Infrastructure Program

PARTICIPANTS: CenterPoint Energy

Atmos Energy – TX

Texas Gas Service

PROGRAM: Rate Stabilization Tariffs

PARTICIPANTS: Atmos Energy – TX

CenterPoint Energy

LAWS: Tex. Util.Code § 104.301

Utah

STATE AUTHORITY: Utah Public Service Commission

PROGRAM: Infrastructure Rate Adjustment Tracker

PARTICIPANT: Questar Gas

Virginia

STATE AUTHORITY: Virginia State Corporation Commission

PROGRAM: Pending

PARTICIPANT: Washington Gas

LAWS: SAVE Act

151 FERC ¶ 61,047
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

[Docket No. PL15-1-000]

Cost Recovery Mechanisms for Modernization of Natural Gas Facilities

(Issued April 16, 2015)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Policy statement.

SUMMARY: In this Policy Statement, the Commission provides greater certainty regarding the ability of interstate natural gas pipelines to recover the costs of modernizing their facilities and infrastructure to enhance the efficient and safe operation of their systems. The Policy Statement explains the standards the Commission will require interstate natural gas pipelines to satisfy in order to establish simplified mechanisms, such as trackers or surcharges, to recover certain costs associated with replacing old and inefficient compressors and leak-prone pipes and performing other infrastructure improvements and upgrades to enhance the efficient and safe operation of their pipelines.

DATE: This Policy Statement will become effective October 1, 2015.

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Docket No. PL15-1-000

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SUPPLEMENTARY INFORMATION:

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Cost Recovery Mechanisms for Modernization of Natural Gas Facilities | Docket No. PL15-1-000

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151 FERC ¶ 61,047
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Philip D. Moeller, Cheryl A. LaFleur,
Tony Clark, and Colette D. Honorable.

Cost Recovery Mechanisms for Modernization of Natural Gas Facilities — Docket No. PL15-1-000

POLICY STATEMENT

(Issued April 16, 2015)

1. On November 20, 2014, the Commission issued a Proposed Policy Statement and sought comments regarding potential mechanisms for interstate natural gas pipelines to use to recover the costs of modernizing their facilities and infrastructure to enhance the efficient and safe operation of their systems.[1] The Commission proposed standards that interstate natural gas pipelines would be required to satisfy to establish simplified mechanisms, such as trackers or surcharges, to recover such costs. Historically, the Commission has required interstate natural gas pipelines to design their transportation rates based on projected units of service. Recently, however, governmental safety and environmental initiatives have raised the probability that interstate natural gas pipelines will soon face increased costs to enhance the safety and reliability of their systems. The Commission issued the Proposed Policy Statement in an effort to address these potential

[1] *Cost Recovery Mechanisms for Modernization of Natural Gas Facilities*, Proposed Policy Statement, 104 FERC ¶ 61,147 (2014) (Proposed Policy Statement).

costs and to ensure that existing Commission ratemaking policies do not unnecessarily inhibit interstate natural gas pipelines' ability to expedite needed or required upgrades and improvements, such as replacing old and inefficient compressors and leak-prone pipelines.

2. After review of the comments on the Proposed Policy Statement, the Commission has determined to establish a policy allowing interstate natural gas pipelines to seek to recover certain capital expenditures made to modernize system infrastructure through a surcharge mechanism, subject to conditions intended to ensure that the resulting rates are just and reasonable and protect natural gas consumers from excessive costs. The Commission recognizes, as many commenters note, that permitting pipelines to recover these expenditures through a surcharge or tracker departs from the requirement that interstate natural gas pipelines design their transportation rates based on projected units of service. We find on balance, however, that consideration of such mechanisms is justified if they are properly designed to limit a pipeline's recovery of such costs to those shown to modernize the pipeline's system infrastructure in a manner that enhances system safety, reliability and regulatory compliance, and are subject to conditions that ensure that the resulting rates are just and reasonable and protect natural gas consumers from excessive costs. Accordingly, we are adopting this Policy Statement to provide guidance and a framework as to how the Commission will evaluate pipeline proposals for recovery of infrastructure modernization costs. The Policy Statement adopts the five guiding principles from the Proposed Policy Statement as the standards a pipeline would have to satisfy for the Commission to approve a proposed modernization cost tracker or

surcharge. Those criteria are (1) Review of Existing Base Rates; (2) Defined Eligible Costs; (3) Avoidance of Cost Shifting; (4) Periodic Review of the Surcharge and Base Rates; and (5) Shipper Support.

3. Below we review the background that led to the development of the Proposed Policy Statement and this Policy Statement, summarize the comments on the Proposed Policy Statement, and discuss the applicability of the Policy Statement in general, and of the five conditions under the new Policy Statement, in light of those comments. As discussed below, the Commission intends that the standards a pipeline must satisfy to implement a cost modernization tracker or surcharge to be sufficiently flexible so as not to require any specific form of compliance but to allow pipelines and their customers to reach reasonable accommodations based on the specific circumstances of their systems. The Commission will thus evaluate any proposal for a modernization cost surcharge against those five standards on a case-by-case basis.

I. Background

A. Safety and Environmental Initiatives

4. As we noted in the Proposed Policy Statement, there have been several recent legislative actions, and resulting regulatory initiatives, to address natural gas pipeline infrastructure safety and reliability. In 2012, Congress passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011.[2] That act includes requirements for

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[2] Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, 49 U.S.C.S. 60101 (2012) (Pipeline Safety Act).

the United States Department of Transportation (DOT) to take various actions to reduce the risk of future pipeline failures. Among other things, the Pipeline Safety Act requires the DOT to (1) consider expansion and strengthening of its integrity management regulations, (2) consider requiring automatic shut-off valves on new pipeline construction, (3) require pipelines to reconfirm their Maximum Allowable Operating Pressures, and (4) conduct surveys to measure progress in plans for safe management and replacement of cast iron pipelines.

5. The Pipeline and Hazardous Materials Safety Administration (PHMSA) is in the process of implementing a multi-year Pipeline Safety Reform Initiative to comply with the Pipeline Safety Act's mandate to enhance the agency's ability to reduce the risk of future pipeline failures.[3] Prior to the Pipeline Safety Act's enactment, on August 25, 2011, PHMSA published an Advance Notice of Proposed Rulemaking (ANOPR) titled "Pipeline Safety: Safety of Gas Transmission Pipelines," which asked all stakeholders whether PHMSA should modify its existing integrity management and other pipeline safety regulations for interstate natural gas pipelines.[4] The ANOPR requested public comment on a range of topics related to current industry practices, the effects of

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[3] Written Statement of Cynthia Quarterman, Administrator, PHSMA, before the U.S. House of Representatives, Committee on Transportation and Infrastructure, Subcommittee on Railroads, Pipelines, and Hazardous Materials (May 20, 2014), *available at* http://transportation.house.gov/uploadedfiles/2014-05-20-quarterman.pdf (Quarterman Testimony) at 3.

[4] *Pipeline Safety: Safety of Gas Transmission Pipelines*, (RIN: 2137-AE72), 76 FR 53,086 (August 25, 2011).

enhanced regulations on safety and cost, and the best method to implement proposed regulations. For example, PHMSA sought comments on shut-off valves and remote controlled shut-off valves. In addition, PHMSA held a public leak detection and valve workshop on March 28, 2012.

6. Also as part of the ANOPR process, PHSMA is considering expanding the definition of a High Consequence Area (HCA) so that more miles of pipeline may become subject to integrity management requirements.[5] PHMSA is also considering potential new rules related to repair criteria, including applying the integrity management repair criteria to non-HCAs; reassessing the repair criteria in areas where the population has grown since the pipeline was constructed; requiring methods to validate in-line inspection tool performance and qualifications of personnel; and implementing risk tiering such that repairs in an HCA have priority over repairs in a non-HCA. PHMSA held a Class Location Methodology workshop on April 16, 2014. Based on the comments from the ANOPR and the workshop, PHMSA "has started drafting a report to Congress on this issue."[6]

7. PHMSA is also considering changes to its requirements that pipelines perform baseline and periodic assessments of pipeline segments in an HCA through one or a

[5] An HCA is a location which is defined in the pipeline safety regulations as an area where pipeline releases have greater consequences to the safety, health and environment. Basically, these are areas with greater population density.

[6] Quarterman Testimony at 10.

combination of in-line inspection, pressure testing, direct assessment of external and internal corrosion, or other technology demonstrated to accurately assess the condition of a pipe. In June 2013, as updated in September 2013, PHMSA issued a flow chart reflecting its draft Integrity Verification Process for natural gas pipelines.[7] To this end, PHMSA seeks information as to what anomalies have been detected using the various assessment methods, and proposes to include criteria in the regulations that would require more rigorous corrosion control.

8. As we further noted in the Proposed Policy Statement, in addition to pipeline safety issues, there have been growing concerns about the emissions of greenhouse gases (GHG) in the production and transportation of natural gas. On April 15, 2014, the United States Environmental Protection Agency (EPA) issued a series of technical white papers, for which it has requested input from peer reviewers and the public, to determine how to best pursue reductions of emissions from, inter alia, natural gas compressors.[8] The EPA Compressor White Paper discusses the most prevalent types of compressors (reciprocating and centrifugal) and compressor emission data. As relevant to this Policy Statement, the EPA lays out several "mitigation options for reciprocating compressors involve[ing] techniques that limit the leaking of natural gas past the piston rod packing,

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[7] 78 FR 56,268 (Sept. 12, 2013).

[8] See EPA, *Oil and Natural Gas Air Pollution Standards, White Papers on Methane and VOC Emission* (Apr. 15, 2014), *availabl*e at http://www.epa.gov/airquality/oilandgas/whitepapers.html

including replacement of the compressor rod packing, replacement of the piston rod, and the refitting or realignment of the piston rod."[9] The EPA also describes several mitigation options for centrifugal compressors to limit the leaking of natural gas "across the rotating shaft using a mechanical dry seal, or capture the gas and route it to a useful process or to a combustion device."[10] If the EPA's white papers result in the agency imposing mitigation requirements on natural gas pipelines, the cost of such controls could be significant.[11]

9. In 2009, the EPA published a rule for mandatory reporting of GHG from sources that, in general, emit 25,000 metric tons or more of carbon dioxide equivalent per year in the United States.[12] This initiative, commonly referred to as the Greenhouse Gas Reporting Program (GHGRP), collects greenhouse gas data from facilities that conduct Petroleum and Natural Gas Systems activities, including production, processing, transportation and distribution of natural gas. Moreover, on November 14, 2014, the

[9] EPA Compressor White Paper at 29.

[10] *Id.* at 29-42.

[11] For example, the Interstate Natural Gas Association of America (INGAA) comments that one of its member companies "reported capital costs of $865,000 for replacement of a wet seal" on a centrifugal compressor. *See* INGAA Comments on EPA Compressor White Paper at 13 (filed June 16, 2014). INGAA also commented on the EPA's Leaks White Paper and noted that many factors could affect leak repair costs and that "the cost of the repair may far exceed the benefit of eliminating a small leak." *See* INGAA Comments on EPA Leaks White Paper at 12-13 (filed June 16, 2014).

[12] Mandatory Reporting of Greenhouse Gases Rule, 74 FR 56,260 (Oct. 30, 2009). *See also* 40 CFR Pt. 98 (2014).

EPA issued a prepublication version of a final rule revising the Petroleum and Natural Gas Systems source category (Subpart W) and the General Provisions (Subpart A) of the GHGRP.[13] The final rule, which was effective January 1, 2015, imposes new requirements for the natural gas industry to monitor methane emissions and report them annually. On that same day, the EPA issued a prepublication version of a proposed rule to add calculation methods and reporting requirements for greenhouse gas emissions, as relevant here, from blow downs of natural gas transmission pipelines between compressor stations. The EPA also proposed confidentiality determinations for new data elements contained in the proposed amendments.[14]

10. As we recognized in the Proposed Policy Statement, one likely result of the Pipeline Safety Act and PHMSA's rulemaking proceedings is that interstate natural gas pipelines will soon face new safety standards requiring significant capital costs to enhance the safety and reliability of their systems. Moreover, pursuant to EPA's initiatives, pipelines may in the future face increased environmental monitoring and

[13] Greenhouse Gas Reporting Rule: 2014 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems, Docket Nos. EPA-HQ-OAR-2011-0512 and FR:-9918-95-OAR (Nov. 14, 2014).

[14] *See* Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determination for Petroleum and Natural Gas Systems, Docket ID No. EPA-HQ-OAR-2014-0831 (issued Nov. 14. 2014).

compliance costs, as well as potentially having to replace or repair existing natural gas compressors or other facilities.[15]

B. Existing Policy

11. The Commission's regulations generally require that interstate natural gas pipelines design their open access natural gas transportation rates to recover their costs based on projected units of service.[16] This requirement means that the pipeline is at risk for under-recovery of its costs between rate cases but may retain any over-recovery. As the Commission explained in Order No. 436, this requirement gives the pipeline an incentive both to (1) "minimize costs in order to provide services at the lowest reasonable costs consistent with reliable long-term service"[17] and (2) "provide the maximum amount of service to the public."[18]

12. Before the Pipeline Safety Act, the Commission held that capital costs incurred to comply with the requirements of pipeline safety legislation or with environmental

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[15] On July 29, 2014, the Department of Energy (DOE) announced steps to help modernize natural gas infrastructure. Moreover, on July 31, 2014, Secretary of Energy Ernest Moniz sent a letter to the Chairman of the Commission recommending the Commission explore efforts to provide greater certainty for cost recovery for new investments in modernization of natural gas transmission infrastructure as part of the FERC's work to ensure just and reasonable natural gas pipeline transportation rates.

[16] 18 CFR 284.10(c)(2) (2014).

[17] *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 436, FERC Stats. & Regs., Regulations Preambles 1982-1985 ¶ 30,665, at 31,534 (1985).

[18] *Id.* at 31,537.

regulations should not be included in surcharges,[19] except in the context of an uncontested settlement.[20] Noting that pipelines commonly incur capital costs in response to regulatory requirements intended to benefit the public interest, the Commission stated that recovering those costs in a tracking mechanism was contrary to the requirement to design rates based on estimated units of service because the use of cost-trackers undercuts the referenced incentives by guaranteeing the pipeline a set revenue recovery.

13. As we stated in the Proposed Policy Statement, however, the Commission recently approved, as part of a contested settlement, a tracker mechanism to recover substantial pipeline modernization costs that Columbia Gas Transmission, LLC (Columbia Gas) demonstrated were necessary to ensure the safety and reliability of its pipeline system.[21] The Columbia Gas settlement outlined significant operational and safety issues resulting from the age and condition of Columbia Gas' system and the corresponding inability to

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[19] *See Granite State Gas Transmission, Inc.*, 132 FERC ¶ 61,089, at P 11 (2010) (*Granite State*); *Florida Gas Transmission Co.*, 105 FERC ¶ 61,171, at PP 47-48 (2003) (*Florida Gas*).

[20] *See e.g., Granite State Gas Transmission, Inc.*, 136 FERC ¶ 61,153 (2011); *Florida Gas Transmission Co.,* 109 FERC ¶ 61,320 (2004). In 2012, the Commission again rejected a protested proposal that would allow a pipeline to recover regulatory safety costs through a tracker, but noted that PHSMA was in the early stages of developing regulations to implement the Pipeline Safety Act, and that the Commission would consider the need for further action as PHMSA's implementation process moved forward. *CenterPoint Energy – Mississippi River Transmission, LLC*, 140 FERC ¶ 61,253, at P 65 (2012) (*MRT*).

[21] *Columbia Gas Transmission, LLC*, 142 FERC ¶ 61,062 (2013) (*Columbia Gas*).

monitor and maintain the system using efficient modern techniques.[22] The Commission found that approving the settlement would facilitate Columbia Gas' ability to make substantial capital investments necessary to correct significant infrastructure problems, and thus provide more reliable service while minimizing public safety concerns.

14. The Commission's determination in *Columbia Gas* thus established general parameters for pipelines to consider when seeking recovery of pipeline investments for modernization costs related to improving system safety and reliability. The tracker approved in that case was designed to recover pipeline modernization capital costs of up to $300 million annually over a five year period. The Commission found that Columbia Gas' settlement included numerous positive characteristics that distinguished its cost tracking mechanism from those the Commission had previously rejected and that work to maintain the pipeline's incentives for innovation and efficiency. The key aspects of the settlement upon which the Commission relied to approve the tracker included the following.

15. First, Columbia Gas worked collaboratively with its customers to ensure that its existing base rates, to which the tracker would be added, were updated to be just and

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[22] Columbia Gas stated in that proceeding that over fifty percent of its regulated pipeline system was over 50 years old, that a significant portion of its system contained dangerous bare steel pipeline, that many of its compressors were also outdated, that many of its control systems were running on obsolete platforms, and that it was only able to inspect a small percentage of its system using modern in-line inspection tools.

reasonable. This included a reduction in Columbia Gas' base rates and a refund to its customers.

16. Second, the settlement specifically delineated and limited the amount of capital costs that may go into the cost recovery mechanism. Moreover, the eligible facilities for which costs would be recovered through that mechanism were specified by pipeline segment and compressor station. Further, the pipeline agreed to spend $100 million in annual capital costs as part of its ordinary system maintenance during the initial term of the tracker, which would not be recovered through the tracker. The Commission found that these provisions should assure that the projects whose costs are recovered through the tracker go beyond the regular capital maintenance expenditures the pipeline would make in the ordinary course of business and are critical to assuring the safe and reliable operation of Columbia Gas' system.

17. Third, the Commission found that a critically important factor to its approval of the settlement was the pipeline's agreement to a billing determinant floor for calculating the cost recovery mechanism, together with an agreement to impute the revenue it would achieve by charging the maximum rate for service at the level of the billing determinant floor before it trues up any cost underrcoveries. The Commission found these provisions should alleviate its historic concern that surcharges, which guarantee cost recovery, diminish a pipeline's incentive to be efficient and to maximize the service provided to the public. The Commission also found that these provisions protect the pipeline's shippers from significant cost shifts if the pipeline loses shippers or must provide increased discounts to retain business.

18. Fourth, the surcharge was temporary and would terminate automatically on a date certain unless the parties agreed to extend it and the Commission approved the extension. Finally, the tracker was broadly supported by the pipeline's customers.

C. <u>Proposed Policy Statement</u>

19. In the Proposed Policy Statement, the Commission found that the ultimate implementation of the recent initiatives described above, to improve natural gas infrastructure safety and reliability and to address environmental issues related to the operation of natural gas pipelines, is likely to lead to the need for interstate natural gas pipelines to make significant capital investments to modernize their systems. The Commission stated that in light of these developments, the Commission has a duty to ensure that interstate natural gas pipelines are able to recover the costs of these system upgrades in a just and reasonable manner that does not undercut their incentives to provide service in an efficient manner and protects ratepayers from unreasonable cost shifts.

20. Accordingly, the Commission proposed to establish a policy outlining the analytical framework for evaluating pipeline proposals for special rate mechanisms to recover infrastructure modernization costs necessary for the efficient and safe operation of the pipeline's system and compliance with new regulations. The Commission proposed to base the policy on the guiding principles established in *Columbia Gas.* Pursuant to the Proposed Policy Statement, a pipeline proposal for a cost recovery tracker to recover pipeline modernization costs would need to satisfy five standards:

(1) **Review of Existing Rates** - the pipeline's base rates must have been recently reviewed, either by means of an NGA general section 4 rate proceeding or through a collaborative effort between the pipeline and its customers; (2) **Eligible Costs** – the eligible costs must be limited to one-time capital costs incurred to modify the pipeline's existing system to comply with safety or environmental regulations issued by PHMSA, EPA, or other federal or state government agencies, and other capital costs shown to be necessary for the safe or efficient operation of the pipeline, and the pipeline must specifically identify each capital investment to be recovered by the surcharge; (3) **Avoidance of Cost Shifting** – the pipeline must design the proposed surcharge in a manner that will protect the pipeline's captive customers from cost shifts if the pipeline loses shippers or must offer increased discounts to retain business; (4) **Periodic Review of the Surcharge and Base Rates** – the pipeline must include some method to allow a periodic review of whether the surcharge and the pipeline's base rates remain just and reasonable; and (5) **Shipper Support** – the pipeline must work collaboratively with shippers to seek shipper support for any surcharge proposal.

21. The Commission sought comments on the Proposed Policy Statement in general and on the five standards noted above. We also sought comments on several related issues, including whether if the Commission were to implement the instant modernization cost recovery policy, it should revise its policy on reservation charge crediting.[23]

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[23] Other questions included whether the costs of modifications to compressors for the purpose of waste heat recovery should be eligible for recovery under a modernization

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D. Comments

22. The Commission received a variety of comments in response to the Proposed Policy Statement.[24] Generally, interstate pipelines and other natural gas facility owners and operators favor the proposed policy, commenting that the criteria for collecting modernization costs through a surcharge should be more flexible than contemplated in the Proposed Policy Statement. Shippers varied in supporting or opposing the proposal, with LDCs conditionally supporting it provided that surcharges are tailored to the individual circumstances of the pipeline, and are designed so as not to impose unreasonable cost burdens or risks on natural gas customers. Some marketers also favored a program allowing the implementation of surcharges for modernization costs. Other shippers, however, including industrials, municipals and supply end entities, oppose the proposed policy statement. Producers are especially opposed to the recovery of any modernization costs through a surcharge mechanism, claiming that to allow such

surcharge, whether there are any capital costs associated with the expansion of the pipeline's existing capacity or its extension to serve new markets that may reasonably be included in the surcharge as necessary one-time capital expenditures to comply with safety and environmental regulations, whether capital costs incurred to minimize pipeline facility emissions be considered for inclusion in the surcharge, even if those costs are not expressly required to comply with environmental regulations, whether non-capital maintenance costs associated with environmentally sound operation of a compressor be considered for inclusion in the surcharge, and under what circumstances should the Commission permit a pipeline to include in the tracking mechanism the costs of additional projects not identified in the pipeline's original filing to establish the tracking mechanism?

[24] See Appendix for a list of those entities and persons that filed comments and/or reply comments to the Proposed Policy Statement.

recovery is contrary to the NGA and longstanding Commission policy. The individuals filing comments also oppose the Proposed Policy Statement for varying reasons.

23. Numerous entities from a wide spectrum of industry interests filed in favor of the Proposed Policy Statement, supporting properly limited tracker or surcharge mechanisms to recover modernization costs.[25] Some advocate granting pipelines added flexibility to comply with the five standards necessary to establish such trackers.[26] Others filing in favor of the Commission's proposed policy state that pipeline cost recovery mechanisms must be tailored to the individual circumstances of the pipeline, and be designed so as not to impose unreasonable cost burdens or risks on natural gas customers.[27] Various pipeline customers generally support the development of simplified mechanisms for the recovery of costs of modernizing pipeline assets to enhance safety and reliability subject to conditions, commenting that the costs to be recovered should be limited to capital

[25] Those commenting in favor include the DOE; PHMSA; the Interstate Natural Gas Association of America (INGAA); Kinder Morgan Interstate Pipelines (Kinder Morgan); Southern Star Central Gas Pipeline, Inc. (Southern Star); Boardwalk Pipeline Partners, LP (Boardwalk); American Midstream (AlaTenn), LLC (American Midstream); the American Gas Association (AGA); the North Carolina Public Utility Commission (NCUC); the Kansas Corporation Commission (KCC); the Michigan Public Service Commission (Michigan PSC); the Tennessee Valley Authority (TVA); and the Environmental Defense Fund, the Conservation Law Foundation, and Sustainable FERC Project (collectively Environmental Commenters).

[26] *See, e.g.*, INGAA Comments at 2, Boardwalk Comments at 4, Kinder Morgan Comments at 5.

[27] *See, e.g.*, AGA Comments at 1 Laclede Comments at 1.

improvements for safety purposes and for compliance with environmental regulations.[28] Others state that modernization cost recovery trackers should include safeguards to ensure that pipelines are not permitted to pass through costs while evading shipper protections traditionally afforded by NGA section 4 rate review.[29] Others support the Proposed Policy Statement as a method for enhancing certainty and the ability of interstate pipelines to recover costs for augmenting the efficient and safe operation of their respective systems.[30]

24. In contrast to the pipelines' and other comments in support of the proposed policy, other commenters, particularly those representing producers, marketers, municipal gas companies, and industrial users of natural gas, expressed strong opposition to the recovery of modernization costs through a tracker.[31] Opponents' claims that additional

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[28] Xcel Energy Services (XES) Comments at 2; Wisconsin Electric and Wisconsin Gas Comments at 4.

[29] Calpine Corporation (Calpine) Comments at 1.

[30] Environmental Commenters Comments at 3-5.

[31] Those filing comments opposing the Proposed Policy Statement include the Natural Gas Supply Association (NGSA), Industrial Energy Consumers of America (IECA), the American Forest and Paper Association (AF&PA), Process Gas Consumers (PGC), the American Public Gas Association (APGA), the Independent Petroleum Association of America (IPAA), Indicated Shippers (Anadarko Energy Services Company, Apache Corporation, BP Energy Company, Chevron U.S.A. Inc., ConocoPhillips Company, Cross Timbers Energy Services, Inc., Direct Energy Business, LLC, ExxonMobil Gas & Power Marketing Company, a division of Exxon Mobil Corporation, Fieldwood Energy LLC, Hess Corporation, Marathon Oil Company, Noble Energy, Inc., Occidental Energy Marketing, Inc., Shell Energy North America (US), L.P., SWEPI LP, and WPX Energy Marketing, LLC), the El Paso Municipal Customer Group (EPMCG), Western Tennessee

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cost-recovery guarantees to incentivize compliance with mandatory environmental and safety laws is misplaced, and that cost trackers are inconsistent with section 284.10(c)(2) of the Commission's regulations, which requires that transportation rates be based on estimated units of service so that the pipeline is at risk for cost under-recovery.[32] Opponents also claim that a cost modernization surcharge would be contrary to longstanding Commission policy and precedent, noting that the Commission has consistently rejected maintenance, compliance, and safety cost trackers, because they guarantee cost recovery without taking into account the benefits of cost reductions in other areas and/or increases in throughput affecting base rate revenues.[33] Those opposing the Proposed Policy Statement further claim that the five standards do not provide the consumer protections afforded under section 4 of the Natural Gas Act (NGA), and that the record lacks a showing that pipelines cannot recover such costs though NGA section

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Municipal Group, the Jackson Energy Authority, City of Jackson, Tennessee, and Kentucky Cities (together, Cities), Independent Oil & Gas Association of West Virginia, Inc. (IOGA), the Municipal Defense Group (MDG), Deep Gulf Energy LP (Deep Gulf), Energy XXI (Bermuda) Ltd. (Energy XXI), EPL Oil & Gas, Inc. (EPL), and M21K, LLC (M21K) (collectively Energy XXI), and Helis Oil & Gas, LLC (Helis) and Walter Oil & Gas Corporation (Walter).

[32] *See, e.g.*, NGSA Comments at 3.

[33] NGSA Comments at 10-11, APGA Comments at 2-4, Indicated Shippers Comments at 5-18 .

4 rate cases.[34] Opponents also claim that the Proposed Policy Statement is premature, because PHMSA and the EPA have not yet issued new regulations.[35]

II. Discussion

A. Adoption of Policy Statement

25. After reviewing the comments filed on the Proposed Policy Statement, the Commission has determined to establish a policy allowing interstate natural gas pipelines to seek to recover certain capital expenditures made to modernize system infrastructure in a manner that enhances system reliability, safety and regulatory compliance through a surcharge mechanism, subject to conditions intended to ensure that the resulting rates are just and reasonable and protect natural gas consumers from excessive costs. While we recognize that allowing pipelines to recover these expenditures through a surcharge or tracker departs from the requirement that interstate natural gas pipelines design their transportation rates based on projected units of service, we find on balance that consideration of such mechanisms is justified in order to provide an enhanced opportunity to recover the substantial capital costs some pipelines are likely to incur to replace aging, unsafe and leak-prone facilities. The Policy Statement provides a framework for how the Commission will evaluate pipeline proposals for recovery of

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[34] APGA Comments at 2-4, NGSA Comments at 7-8.

[35] NGSA Comments at 8-9.

infrastructure modernization costs, and guidance as to how it will evaluate such proposals in accordance with the five adopted standards.

26. As the comments in support of the Commission's Proposed Policy Statement indicate, establishment of a policy to permit enhanced recovery of modernization costs is in the public interest and necessary to address concerns regarding the safety of the Nation's natural gas infrastructure and the safe operation of natural gas pipelines, as well as environmental issues related to emissions. With regard to safety and reliability, as OPS comments, recent pipeline accidents, including the September 2010 pipeline rupture in San Bruno, California, demonstrate the potential consequence of aging pipeline facilities that are not properly repaired, rehabilitated or replaced. OPS states that 59 percent of existing natural gas pipelines were built before 1970 and 69 percent of existing natural gas pipelines were built before 1980. DOE notes that more than half of the country's natural gas transmission and gathering infrastructure is over 40 years old. As OPS points out, while aging pipelines are not inherently risky, older facilities have been exposed to more threats and were likely constructed without the benefit of today's safety standards or quality materials.

27. To address these concerns, Congress passed the Pipeline Safety Act mandating that DOT take various actions to improve the safety of interstate natural gas pipelines, including requiring testing to verify natural gas pipelines' maximum allowable operating pressure, considering expansion and strengthening of its integrity management regulations, and considering requiring automatic shut-off valves on new pipeline construction. The need to address pipeline safety is also supported by OPS' comments

that multiple recommendations from the National Transportation Safety Board and the General Accounting Office reinforce the need to ensure that the Nation's pipeline infrastructure is sound and reliable. The DOE states in its comments that the Commission's proposal is "aligned with goals of DOE's Initiative to Help Modernize Natural Gas Transmission and Distribution Infrastructure as well as government-wide efforts to improve pipeline safety and enhance the resilience of our nation's critical infrastructure.[36] DOE asserts that offering streamlined cost recovery options will provide an overdue incentive for pipelines to invest in new equipment and upgrades that will improve safety, boost energy efficiency and reduce emissions.

28. In addition to pipeline safety issues, there have been growing concerns about the emissions of GHG in the production and transportation of natural gas. As we noted in the Proposed Policy Statement, in 2014, the EPA issued a series of technical white papers to determine how to best pursue reductions of emissions from, inter alia, natural gas compressors. The EPA Compressor White Paper lays out several "mitigation options for reciprocating compressors and centrifugal compressors to limit the leaking of natural gas…."[37] Further, in 2009, the EPA published its rule for mandatory reporting of greenhouse gas emissions. The resulting GHGRP collects greenhouse gas data from facilities that conduct Petroleum and Natural Gas Systems activities, including

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[36] DOE Comments at 1.

[37] EPA *Oil and Natural Gas Sector Compressors (Apr. 2014) at* 29, available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415compressors.pdf at 29.

production, processing, transportation and distribution of natural gas. Moreover, the EPA issued a final rule effective January 1, 2015, imposing new requirements for the natural gas industry to monitor methane emissions and report them annually.

29. Further, the use of natural gas as a fuel for compressors adds to the amount of carbon dioxide emissions.[38] DOE also estimates that over 110 Bcf of natural gas is lost annually through routing venting and equipment leaks. DOE states that a streamlined cost recovery mechanism such as that proposed here for voluntary emissions reductions can benefit pipelines and their customers. According to DOE, infrastructure improvements that will increase compressor efficiency and reduce venting and leaking of methane emissions will also result in product conservation and thus cost savings.[39]

30. The safety and reliability of the nation's natural gas infrastructure, and the operation of those facilities in an efficient manner that minimizes environmental impact, are issues of public interest, and the development of mechanisms to encourage investments in infrastructure improvements and upgrades to enhance the efficient and safe operation of natural gas pipeline furthers that interest. As we recognized in the Proposed Policy Statement, one likely result of the recent regulatory safety and environmental initiatives is that interstate natural gas pipelines will face increased costs

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[38] See DOE Comments at 4, stating that EIA estimates that 728 billion cubic feet (Bcf) of natural gas was used as fuel by compressor stations operating at natural gas transmission and storage facilities in the United States in 2012, resulting in 39 million metric tons of CO2 emissions.

[39] DOE Comments at 5.

related to those rules and programs. Notably, while the opponents of the policy assert its implementation is premature because the amount of those costs is still unknown, they do not dispute that pipelines are likely to incur substantial costs to address these issues. In light of the referenced regulatory developments, the Commission has a duty to ensure that interstate natural gas pipelines are able to recover the costs of these required system upgrades in a just and reasonable manner that does not undercut their incentives to provide service in an efficient manner and also protects ratepayers from unreasonable cost shifts.

31. In an effort to ensure that consumers are protected against potential effects of any modernization cost trackers or surcharges, the Final Policy adopts the five guiding principles proposed in the Proposed Policy Statement as the standards a pipeline would have to satisfy for the Commission to approve a proposed modernization cost tracker or surcharge. Those standards are (1) a requirement for a review of the pipeline's existing base rates by means of an NGA general section 4 rate proceeding, a cost and revenue study, or through a collaborative effort between the pipeline and its customers; (2) a requirement that the costs eligible for recovery through the tracker or surcharge must generally be limited to one-time capital costs incurred to modify the pipeline's existing system to comply with safety or environmental regulations or other federal or state government agencies, or other capital costs shown to be necessary for the safe, reliable, and/or efficient operation of the pipeline, and the pipeline must specifically identify each

projects' costs or capital investment to be recovered by the surcharge;[40] (3) a prohibition against cost shifting, requiring that the pipeline design any proposed surcharge in a manner that will protect the pipeline's captive customers from cost shifts if the pipeline loses shippers or must offer increased discounts to retain business; (4) a requirement that the pipeline must include some method to allow a periodic review of whether the surcharge and the pipeline's base rates remain just and reasonable; and (5) a requirement that the pipeline work collaboratively with shippers to seek shipper support for any surcharge proposal. These standards will act as protections against pipelines unilaterally recovering costs through a tracker that do qualify as the type intended to meet the goals of the policy. They will also require any pipeline seeking a modernization cost tracker to demonstrate to the Commission and its customers that its current base rates are just and reasonable, and provide flexibility for the parties to pursue options to reach agreement on processes to ensure that those rates and the surcharge rate remain just and reasonable. They will also prevent shifting of additional costs to captive customers.

32. Opponents of the proposed policy argue that adopting the Proposed Policy Statement would be contrary to the NGA, longstanding Commission policy and rate regulation principles, and that the Commission has neither justified this departure from current policy nor demonstrated why it is necessary. NGSA, Indicated Shippers, the IPAA and others argue that the NGA requires that pipelines be afforded an "opportunity"

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[40] As discussed below, the Commission may consider pipeline proposals to include certain limited non-capital maintenance costs in a modernization cost tracker.

to recover their reasonable costs but that trackers guarantee cost recovery in violation of that principle.[41] They assert this guaranteed cost recovery, absent any accounting of cost savings, is the reason Commission has for years disfavored cost recovery trackers, because it eliminates the pipeline's risk and correspondingly any incentive for the pipeline to be efficient and to provide effective service. They note that the Commission's rejections of such mechanisms include proposals addressing circumstances very similar to those that would be covered under the new policy, and that the Commission itself has stated that it has only approved the use of trackers that were agreed to in settlements.[42] They further claim that there has been no change in the law or the rationale underlying the Commission's longstanding position that would warrant the policy modification proposed.

33. As we stated above, the Commission acknowledges that the policy adopted in this Policy Statement departs from the general rate policy in our regulations that interstate natural gas pipelines design their transportation rates based on projected units of service. We disagree, however, that there have been no changes that may result in tracker mechanisms being just and reasonable in certain circumstances and subject to appropriate controls.[43] As discussed above, the increased concerns with pipeline safety reflected in

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[41] *See, e.g.*, NGSA Comments at 10, Indicated Shippers' Comments at 3.

[42] *See, e.g.*, Indicated Shippers' Comments at 5– 11, and cases cited therein.

[43] Proposed Policy Statement, PP 18-20.

the Pipeline Safety Act, together with the recent DOE, PHMSA, and EPA initiatives to improve natural gas infrastructure safety and reliability and to address environmental issues will result in certain increased capital and compliance costs for pipelines. In light of these developments the Commission has a duty to ensure that interstate natural gas pipelines are able to recover the reasonable cost of these system upgrades in a just and reasonable manner that does not undercut their incentives to provide service in an efficient manner and protects ratepayers from unreasonable cost shifts.

34. We also disagree with commenters' contentions that allowing modernization cost trackers will eliminate the pipeline's risk of cost under-recovery and thereby reduce pipelines' incentives to be efficient and to provide effective service, contrary to goals of our general policy of requiring that rates be based on projected units of service. As discussed in more detail below, the costs included in a modernization cost tracker will generally be limited to one-time capital costs to improve the safe, reliable, and/or efficient operation of the pipeline. Thus, pipelines will continue to recover all other costs in their base rates pursuant to the Commission's ordinary ratemaking policies. Therefore, pipelines will continue to be at risk between rate cases for recovery of their operating and maintenance (O&M) costs, the overall return on non-modernization capital costs, the depreciation allowance related to those costs, and all other costs included in their base rates.[44] This will give pipelines an incentive to operate their systems as efficiently as

[44] This fact distinguishes surcharges that may be approved under the Policy Statement from *ANR Pipeline Co.*, 70 FERC ¶ 61,143 (1995), where we rejected ANR's

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possible, consistent with Commission policy. Moreover, the pipelines will have the burden of showing that all costs included in a modernization cost tracker are prudent and consistent with the Commission's eligibility standards for including costs in such a tracker. This will give the Commission and all interested parties an opportunity to review whether the subject capital investments are prudent and required for the safe and efficient operation of the pipeline.

35. Several commenters, including Indicated Shippers, contend that the Proposed Policy Statement is contrary to Commission precedent prohibiting tracker mechanisms for regulatory obligations, and discuss a number of cases where we had rejected pipeline proposals for regulatory compliance cost trackers.[45] As noted above, the Commission does not disagree that we have previously rejected proposed tariff provisions that would establish trackers to recover costs not wholly dissimilar to those contemplated by the Policy Statement. None of those proposals, however, included conditions and safeguards to protect shippers and consumers of the sort that the *Columbia* settlement did, and which we adopt here as conditions for a modernization cost tracker.

36. As we noted in our order approving Columbia Gas' surcharge, Columbia Gas' proposal contained numerous benefits and protections agreed to with its shippers that

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proposed base rate cost- of-service tracker, which sought to recover all of the pipeline's cost of service, as contrary to our regulations.

[45] *See*, *e.g.*, Indicated Shippers' Comments at 5– 11.

distinguished it from our orders rejecting tracker proposals.[46] Notably the development of Columbia Gas' tracker for costs to make necessary improvements and upgrades to its system began with Columbia Gas and its shippers engaging in a collaborative effort to review Columbia Gas' current base rates, leading to Columbia Gas' agreement to make significant reductions to its base rates and to provide refunds to its shippers.[47] Further the settlement identified by pipeline segment and compressor station, the specific Eligible Facilities for which costs may be recovered, and limited the amount of capital costs and expenses for each such project.[48] It also established a billing determinant floor for calculating the surcharge imputing the revenue it would achieve by charging the maximum rate for service at the level of billing determinant floor before it trues up any cost under-recoveries.[49] Further, Columbia Gas' tracker is temporary, and terminates by

[46] *Columbia Gas*, 142 FERC ¶ 61,062 at PP 22-27.

[47] *Id.* P 22.

[48] We noted that this distinguished *Columbia Gas* from the surcharge mechanisms we rejected in *Florida Gas*, 105 FERC ¶ 61,171 at PP 47-48 and *MRT*, 140 FERC ¶ 61,253, which contained only general definitions of what type of costs would be eligible for recovery, leaving the pipeline considerable discretion as to what projects it would subsequently propose to include in the surcharge and creating the potential for significant disputes concerning the eligibility of particular projects.

[49] As we also noted, the surcharge mechanisms proposed in *Florida Gas*, *MRT*, and *Granite State Gas Transmission, Inc.*, 132 FERC ¶ 61,089 (2011), did not include a comparable mechanism to protect captive customers from significant cost shifts. The surcharges proposed in the other cases cited by Indicated Shippers as examples of the Commission's policy against surcharges and trackers, including *ANR Pipeline Company*, 70 FERC ¶ 61,143, and *El Paso Natural Gas Co.*, 112 FERC ¶ 61,150 (2005), also did not contain the safeguards or customer protections included in the Columbia Gas

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its terms subject to extension requiring the consent of all parties, and thus will not become a permanent part of Columbia Gas' rates. Finally, the tracker settlement was supported or not opposed by virtually all of Columbia Gas' shippers.

37. The Commission's approval of any modernization cost tracker or surcharge will require a showing by the pipeline of the same types or benefits that distinguished Columbia Gas' tracker from those we had rejected, and thus comments that the Policy Statement would represent a complete reversal of Commission policy are exaggerated. This Policy Statement does not provide pipelines with any ability to establish a modernization surcharge other than in the manner and with the same protections Commission has already approved in *Columbia Gas*. The analysis to be performed under this Policy Statement will be substantially similar to that undertaken to find that Columbia Gas' modernization cost recovery mechanism was just and reasonable and benefitted all interested parties. It will be incumbent on a pipeline requesting a modernization cost tracker to demonstrate that its proposal includes the types of benefits that the Commission found maintained the pipeline's incentives for innovation and

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settlement and implemented for the Final Policy. Similarly, the greenhouse gas cost recovery mechanism we rejected as premature in *Southern Natural Gas Co.*, 127 FERC ¶ 61,003 (2009), did not provide safeguards of the type required by this Policy Statement. Likewise, our rejection in *Tennessee Gas Pipeline Co., LLC* and *Kinetica Energy Express, LLC*, 143 FERC ¶ 61,196 (2013) of a proposed hurricane surcharge that we found to be overly broad because it sought to recover costs outside those caused by hurricanes, storms or other natural disasters, did not include any of the referenced protections. *Id.* P 225.

efficiency, and distinguished Columbia Gas' modernization cost tracking mechanism from those the Commission had previously rejected.

38. Further, the requirements that a pipeline proposing a tracker mechanism must establish that its base rates are just and reasonable and that there be provision for a periodic review of surcharge and base rates should alleviate concerns that the Final Policy will result in pipelines not filing NGA section 4 rate proceedings and thus being insulated from rate review. APGA points to examples of interstate pipelines having not filed NGA section 4 rate cases in over a decade and asserts that pipelines generally file rate cases very infrequently, thus depriving customers of an opportunity to review all the pipeline's rates for lengthy periods. However, the fact that a pipeline desiring a modernization cost surcharge must establish that its existing base rates are just and reasonable should increase customer opportunities to obtain review of all the pipeline's rates. As discussed in more detail below, if a pipeline's shippers protest a filing to establish a modernization cost tracker on the ground that the pipeline has not shown that its base rates are just and reasonable, the Commission will establish appropriate procedures to enable it to make a finding, based on substantial evidence, whether the base rates are just and reasonable. Moreover, while offsetting decreases in cost items will not be reflected in rates during the time between the effective date of the surcharge and the first periodic review, that periodic review will provide an opportunity for any offsetting cost reductions to be reflected in rates in order to assure that the base rates and any continued surcharge are just and reasonable.

39. Accordingly, given the heightened sensitivity to pipeline safety and environmental related concerns, and based on the benefits realized from the *Columbia Gas* settlement, which enabled the pipeline to efficiently make necessary upgrades and repairs to maintain the safety and reliability of its system while ensuring that its shippers were protected against cost shifts and other potential pitfalls commonly associated with trackers, the Commission has determined to modify its policy to permit the use of a tracker mechanism in the limited circumstances provided for under the Policy Statement, which will inure to the public interest.

40. As noted, several commenters advocate that the Commission's modernization cost recovery policy contain narrowly drawn conditions and require strict adherence to those conditions to obtain approval for such a mechanism. As many others comment, however, the Policy Statement will be most effective and efficient if designed according to flexible parameters that will allow for accommodation of the particular circumstances of each pipeline's circumstances. Maintaining a transparent policy with flexible standards will best allow pipelines and their customers to negotiate just and reasonable, and potentially mutually agreeable, cost recovery mechanisms to address the individual safety, reliability, regulatory compliance and other infrastructure issues facing that pipeline. For example, while we will require that any pipeline seeking a modernization cost tracker demonstrate that its existing base rates are just and reasonable, as some commenters point out, there may not be a need in all circumstances for a pipeline to file and litigate an NGA section 4 rate proceeding to make such a showing. There may be less costly and less time consuming alternatives. As we stated in the Proposed Policy Statement, the

Commission proposed the new policy to "ensure that existing Commission ratemaking policies do not unnecessarily inhibit interstate natural gas pipelines' ability to expedite needed or required upgrades and improvements."[50] Thus, while we are imposing specific conditions on the approval of any proposed modernization cost tracker, leaving the parameters of those conditions reasonably flexible will be more productive in addressing needed and required system upgrades in a timely manner. Further, consistent with this approach, the Commission will be able to evaluate any proposals in the context of the specific facts relevant to the particular pipeline system at issue.

41. Accordingly, the Commission finds that modification of our previous policy is warranted to allow for consideration of pipeline proposals for modernization cost tracking mechanisms as a way for pipelines to recover those costs in a timely manner while maintaining the safe and efficient operation of pipeline systems. As we discuss more fully below, however, the Commission's approval of any such mechanism will be subject to the Commission's scrutiny of the proposal and its evaluation of the stated conditions, which will work to protect the pipeline's customers and ratepayers against potential adverse effects of any tracker. That analysis will be on a case-by-case basis, and thus will take into account the specific circumstances of the individual pipeline and its customers. Any shippers opposing the pipeline's proposal will have a full opportunity to express their position on specific aspects of the proposed mechanism at

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[50] Proposed Policy Statement at P 9.

that time, and the pipeline will need to engage in a collaborative effort to garner significant shipper support before the Commission will approve a tracker proposal.

42. Opponent commenters also claim that there is no need for the Proposed Policy Statement because there are sufficient longstanding procedural options and mechanisms in place to achieve the Commission's cost recovery goals in this initiative, including NGA rate cases and the Commission's settlement process. Again, the Commission does not dispute that there are existing procedures that provide pipelines an opportunity to recover their just and reasonable costs. The instant Policy Statement, however, is meant to address imminent and foreseeable developments related to the safety and reliability of the natural gas interstate pipeline system. Thus, we find it warranted in the limited circumstances under which the Commission would approve a modernization cost surcharge, to allow recovery through a tracker of those costs expended to replace old and inefficient compressors and leak-prone pipes and performing other infrastructure upgrades and improvements to enhance efficient and safe operation of their pipeline systems.

43. We disagree with comments that the Policy Statement is premature because the regulatory initiatives prompting the new policy are not yet finalized, and thus the projected increased costs are unknown and speculative. Although the commenters are correct that the regulatory initiatives that are the impetus for the Final Policy are not final, there is little debate that some form of them will be in place eventually, and that they will result in increased costs to pipelines. It will take pipelines a significant amount of time to review and analyze their systems to determine if there are portions that need immediate

attention, and whether the projects they identify in their review are of the sort that would be eligible for a cost modernization tracker. It is reasonable for the Commission to establish this policy in advance of the final initiatives to provide guidance to the industry as to how the Commission will analyze pipeline's proposals to address these questions. Further, this Policy Statement will be beneficial to those pipelines that decide to take a proactive approach to ensuring system safety and reliability by conducting system and rate reviews prior to governmental mandates requiring them to do so. [51]

B. Standards for Modernization Cost Trackers or Surcharges

44. As discussed, this Policy Statement permits pipelines to seek Commission approval of modernization cost trackers or surcharges to recover costs associated with performing infrastructure upgrades and replacements in a manner that will enhance the efficient and safe operation of their pipelines. The Commission's evaluation and approval of any proposed modernization cost tracker will require the proposing pipeline to satisfy the five standards from the Proposed Policy Statement. We discuss the application of those standards under the Policy Statement below.

1. Review of Existing Rates

45. Under the first standard proposed by Commission, a pipeline proposing a tracker mechanism must establish that the base rates to which any surcharges would be added are

[51] For the same reasons, we decline to adopt NGSA's suggestion in its reply comments that we defer issuing this Policy Statement until after PHMSA and EPA issue final regulations.

just and reasonable and reflect the pipeline's current costs and revenues as of the date of the initial approval of the tracker mechanism. The Commission proposed that the pipeline could do this in various ways, including (1) making a new NGA general section 4 rate filing, (2) filing a cost and revenue study in the form specified in section 154.313 of the Commission's regulations showing that its existing rates are just and reasonable, or (3) through a collaborative effort between the pipeline and its customers. The Commission sought input on these or other acceptable approaches for pipelines to demonstrate that existing base rates are just and reasonable.

a. Comments

46. Some commenters suggested that the Commission require pipelines to file an NGA section 4 rate case as part of any proposed capital cost tracker. IPAA and the NGSA argue that adoption of a capital cost tracker must require a comprehensive review of the pipeline's base rates and cost of service through an NGA general section 4 rate filing with hearing procedures that include discovery and the Commission's Office of Administrative Litigation staff. TVA states that it feels strongly that any such review would be best accomplished through the thorough and objective analysis of a section 4 rate filing. PEG argues that pipelines should be required to restate all of their rates under NGA section 4 within three years prior to a surcharge. Laclede also argues that a cost and revenue study is not a reasonable substitute for an NGA section 4 filing.

47. The NYPSC, the NCUC and the KCC agree that a pipeline's base rates must be reviewed through a full NGA general section 4 rate proceeding or through a collaborative effort between the pipeline and its customers, and oppose allowing pipelines to only file a

cost and revenue study. Cities and Municipals commented that the collaborative effort standard should be abandoned in favor of a clear standard based on a section 4 general rate case where all the pipeline's costs can be reviewed. Others comment that the pipeline's rates should have been reviewed and approved within a certain time-frame (3 or 4 years) prior to the implementation of a surcharge, and that the Commission should require pipelines with such surcharges to file rate cases on a regular basis (every 3 years).

48. Others comment, however, that a full NGA section 4 rate case review would be too cumbersome for the purpose of efficiently implementing appropriate cost modernization surcharges. INGAA argues that the Commission should remain open to alternative approaches to justifying existing base rates. Recognizing that rate cases, cost and revenue studies and recent rate settlements are all appropriate methods for determining that existing base rates are just and reasonable, INGAA asserts that these are not the only circumstances in which relevant rates may be reviewed and approved by the Commission, and that the Commission should remain open to other possibilities. For example, INGAA argues that the Commission should allow a pipeline to introduce a cost recovery mechanism when such a proposal is broadly supported by shippers, regardless of whether the settlement addresses other rate issues, or when the pipeline has an upcoming obligation to file a general NGA section 4 rate filing, a cost and revenue study, or restatement or re-justification of its rates as the result of a settlement provision. INGAA further states that a recent review of a pipeline's base rates may be irrelevant to the analysis of a cost tracker when all, or the vast majority, of a pipeline's shippers have entered into long-term negotiated rate agreements accepted by the Commission. INGAA

asserts that a cost recovery mechanism also may be appropriate when the Commission recently has reviewed and approved a pipeline's base rates in an NGA section 7 proceeding to ensure that new pipelines are not placed at a disadvantage.

49. Calpine recommends the review of a pipeline's base rates occur through an informal collaborative process and not a general section 4 rate case. APGA argues that permitting the rate review to occur through a new NGA general section 4 rate filing or a cost and revenue study, as opposed to requiring a pre-negotiated base rate settlement, would eliminate the benefit of the *Columbia Gas* case, namely negotiations among the pipeline and its customers regarding substantial rate reductions and refunds, which led to agreement on a just and reasonable rate level. XES suggests having pipelines file a cost and revenue study because it would allow pipeline to file an 'unadjusted' report so that current costs and revenues may be determined. The Environmental Commenters express concern that requiring a general section 4 rate filing as a prerequisite could be inapposite to the regulatory efficiency purposes of a cost tracker.

50. American Midstream requests that the Commission clarify that to be eligible for the special cost recovery mechanism through a limited section 4 filing, pipelines or at least small pipelines like American Midstream need only demonstrate that they are not recovering their reasonable costs under their existing recourse rates, and will not be required to file testimony specifically supporting and explaining each of the schedules required by section 154.313 of the Commission's regulations.

b. **Determination**

51. Under this Policy Statement, any pipeline seeking a modernization cost recovery tracker must demonstrate that its current base rates to which the surcharge would be added are just and reasonable. This is necessary to ensure that the overall rate produced by the addition of the surcharge to the base rate is just and reasonable, and does not reflect any cost over-recoveries that may have been occurring under the preexisting base rates.

52. In the Proposed Policy Statement, we stated that the pipeline could demonstrate its base rates are just and reasonable by filing a NGA section 4 general rate proceeding, a cost and revenue study in the form specified in section 154.313 of the Commission's regulations, or through some other collaborative effort between the pipeline and its customers. In applying the Final Policy we decline to require that such rate review be conducted only through an NGA section 4 rate proceeding. The type of rate review necessary to determine whether a pipeline's existing rates are just and reasonable is likely to vary from pipeline to pipeline. For example, it may be possible for some pipelines to demonstrate that their existing base rates are under-recovering their full cost of service and that a section 4 rate filing would likely lead to an increase in their base rates through a showing short of filing an NGA section 4 rate proceeding. Therefore, we remain open to considering alternative approaches for a pipeline to justify its existing rates.

53. We note, however, that any pipeline seeking a modernization cost surcharge will need to satisfy the Commission that its current base rates are no higher than a just and reasonable level. To that end, we encourage any pipeline seeking approval of a

modernization cost tracker to engage in a full exchange of information with its customers to facilitate that process. If a voluntary exchange of information fails to satisfy interested parties that a pipeline's base rates are just and reasonable, the Commission will establish appropriate procedures to enable resolution of any issues of material fact raised with respect to the justness and reasonableness of the pipeline's base rates based upon substantial evidence on the record. In this regard, the Commission notes that, if the pipeline files a contested settlement concerning its base rates, the Commission would consider whether to approve the settlement pursuant to the approaches discussed in *Trailblazer Pipeline Co.*[52]

2. Defined Eligible Costs

54. In the Proposed Policy Statement, we stated that to qualify as "eligible costs" for recovery under a cost modernization tracker, costs must be limited to one-time capital costs incurred to modify the pipeline's existing system or to comply with safety or environmental regulations issued by PHMSA, EPA, or other federal or state government agencies, and other capital costs shown to be necessary for the safe or efficient operation of the pipeline. The Commission also recognized that interstate natural gas pipelines routinely make capital investments related to system maintenance in the ordinary course of business, and the Commission stated that such routine capital costs could not be included in a cost modernization tracker.

[52] 87 FERC ¶ 61,110, at 61,438-41 (1999). *See e.g.*, *Texas Gas Transmission, LLC*, 126 FERC ¶ 61, 235 (2009); *Devon Power LLC*, 117 FERC ¶ 61,133 (2006).

55. The Commission also proposed to require that each pipeline specifically identify each capital investment to be recovered by the surcharge, the facilities to be upgraded or installed by those projects, and an upper limit on the capital costs related to each project to be included in the surcharge. The Commission stated that this would allow an upfront determination that the costs are eligible for recovery through the tracker and avoid later disputes about which costs or facilities qualify for such recovery.

56. The Commission also asked several questions concerning what costs should be eligible for recovery in a tracker.

a. Comments

57. The majority of commenters agree that proponents of a modernization cost recovery tracking mechanism should specify the costs and identity of projects to be recovered pursuant to any such mechanism and limit the recovery of those costs. AGA argues that pipelines should be required to clearly specify the investments which will be recovered through the tracking mechanism, and that shippers should have the ability to challenge the inclusion of projects or costs as part of the collaborative process. Several commenters, including NGSA, IOGA, XES, and Environmental Commenters note that facilities eligible for cost recovery under a capital cost tracker should be limited to modification of the pipeline's existing system for reliability, safety, or environmental compliance, and that there be a strict distinction between such facilities and maintaining the pipeline system in the ordinary course of business. NGSA argues that eligible tracked costs for recovery in a surcharge should be strictly limited to one-time capital costs related solely to compliance with the incremental requirements of future PHMSA and

EPA regulations, as opposed to the inclusion of ordinary capital maintenance costs. EPMCG states the Proposed Policy fails to explain how the Commission could distinguish between such normal expenditures and those "necessary to address, safety, efficiency or similar concerns." Southern Companies suggests using an Eligible Facilities Plan, comparable to that used in the *Columbia Gas* settlement.

58. Wisconsin Electric and Wisconsin Gas suggest that pipelines be required to specify the regulation that resulted in the requirement to construct each project and to either file for approval of each project under the NGA section7(c) certificate application process or in the event that a section 7(c) certificate application is not required, then provide all information about the project in a manner similar to a section 7(c) application. Wisconsin Electric and Wisconsin Gas also suggest the Commission establish clear criteria for an "eligible modernization project" and create a clear distinction between routine maintenance projects versus modernization projects undertaken to comply with safety and/or environmental regulations.

59. Those opposed to the Policy Statement in general advocate strict limits on the "eligibility" of modernization costs that can be recovered through a surcharge. The AF&PA for example, opposes recovery of modernization costs through a surcharge and states that the costs the pipeline seeks to recover through the tracker/surcharge must be one time capital costs incurred to comply with safety or environment regulation issued by a governmental entity and such costs are necessary for the safe or efficient operations of the pipeline. AF&PA states to the extent that the Commission allows trackers, the Commission should only permit trackers related to costs that are specifically tied to laws

that have already been enacted or regulations that are currently effective. AF&PA comments that the pipeline should be required to demonstrate that the costs are incremental to the costs imposed under existing laws and regulations. Laclede, who also opposes the Proposed Policy Statement, echoes the notion that modernization costs should only be recoverable through rate trackers if the costs are tied to new safety or health requirements. Additionally, the Industrial Energy Consumers of America (IECA) opposes surcharges and trackers as a way for pipeline companies to recover regulatory safety and environmental costs, arguing that it should be a requirement for pipeline companies to file a new tariff that includes regulatory costs. IECA recommends strict guidelines as to what costs pertain to eligible facilities for special cost recovery.

60. Several commenters stated that the Commission needs to ensure that pipelines do not recover costs related to the safe and efficient operation of their systems that they should have already been spending. NCUC states that pipelines should not be provided incentives to make the investments it already should have made. Calpine also states pipelines should already be complying with safety and reliability requirements imposed by existing regulations and should not be incented to recover such costs through a modernization cost mechanism. PEG opposes the Commission's involvement in the mandates of other agencies such as EPA and PHMSA. According to PEG, "it is presumptuous of the Commission to describe such expenditures as being in 'advancement of the public interest' when first, the public interest is yet to be defined by regulatory

action and second, such actions are outside of the Commission's purview."[53] PEG fails to see any reason to provide an incentive for pipelines to take actions that they must take under penalty of law.

61. Other commenters found the Commission's proposal with regard to eligible facilities too restrictive, and stated that costs should not be limited to "one-time, capital costs." INGAA argues that limiting the tracker mechanism only to capital costs is an unnecessary limitation on the type of costs that should be eligible for inclusion into the tracker mechanism, and urge expansion of the scope of the definition of eligible facilities. WBI Energy likewise comments that a one-time capital cost limitation may preclude a pipeline from recovering non-routine non-capital expenses which were prudently incurred to address system safety or efficiency. WBI Energy thus argues the final policy should be flexible enough to address each pipeline's situation.

62. Boardwalk states that the policy should be flexible so that if as a result of the modification process a pipeline discovers other actions that need to be taken in order for a pipeline to be in compliance with the new PHMSA rules, the costs of those activities may be included in the tracker. Boardwalk states the Commission should provide clear and rational guidance as to categories of costs eligible for inclusion in the tracker. Columbia Gas argues that the Commission should allow pipelines and shippers to include the cost of projects intended to increase the reliability or safety of existing facilities, including

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[53] PEG Comments at 7.

those facilities not necessarily impacted by regulations, provided that pipelines make a clear showing of net benefits to its stakeholders. Columbia Gas suggests such potential benefits may include improved safety, reduced emissions, increased efficiency or reliability, reduced costs, improved fuel, or reduced lost-and-unaccounted-for quantities.

b. Determination

63. Consistent with the Proposed Policy Statement, costs proposed to be recovered through a modernization cost surcharge (Eligible Costs) should generally be limited to (1) one-time capital costs incurred to modify or replace existing facilities on the pipeline's system to comply with safety or environmental regulations issued by PHMSA, EPA, or other federal or state government agencies, or (2) other one-time capital costs shown to be necessary for the safe or efficient operation of the pipeline.[54] The Commission does not intend that capital costs the pipeline incurs as part of its ordinary, recurring system maintenance requirements should be eligible for inclusion in a modernization cost tracker. The Commission is modifying its rate policies to permit modernization cost trackers primarily for the purpose of allowing pipelines to recover capital costs incurred to upgrade the older parts of their systems (1) to comply with new, more stringent regulatory requirements and/or (2) take advantage of new technologies

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[54] In the Proposed Policy Statement, at P 23, the Commission proposed to define eligible costs as "one-time capital costs to *modify* the pipeline's existing system . . ." (emphasis supplied). Some commenters have interpreted our use of the word "modify" to exclude the costs of facility replacement projects from eligibility. We clarify that capital costs to replace existing facilities, such as old compressors that do not comply with new EPA emission requirements, are eligible for inclusion in a modernization cost tracker.

that reasonably increase safety and/or efficiency, such as reductions in methane leaks, system modifications to allow the use of advanced in-line inspection tools in lieu of hydrostatic testing, or replacement of old compressors with newer more energy efficient ones.[55]

64. By contrast, the Commission believes that pipelines should continue to recover in their base rates ordinary capital costs of the type they routinely incur as part of their regular system maintenance. The Commission recognizes the potential difficulty in distinguishing between ordinary capital costs for system maintenance, which should be excluded from a modernization cost tracker, and capital costs for system upgrades, which are reasonably included in such a tracker. In order to address this concern, the parties may, as INGAA and others suggest,[56] consider including in a modernization cost tracker a mechanism for ensuring that a representative level of ordinary system maintenance capital costs are excluded from the tracker. For example, the Columbia Gas settlement includes a provision that Columbia Gas will continue to make capital expenditures of $100 million annually for system maintenance and those expenditures will not be included in its modernization cost tracker. If Columbia Gas spends less than that amount in any year, the difference must be used to reduce the plant investment included in the

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[55] *See, e.g.*, INGAA Comments at 13.

[56] INGAA reply comments at 18-19. Environmental Commenters at 12-13.

modernization cost tracker.[57] In developing such a mechanism, the parties could use the pipeline's recent history of capital expenditures incurred for routine maintenance as a basis for determining a representative level of ordinary system maintenance capital costs to be excluded from the modernization cost tracker.

65. Some commenters have suggested that the Commission should permit certain non-capital expenses to be included in a modernization cost tracker, if they are non-routine and required by regulation or a voluntary program adopted by a pipeline as a best practice.[58] Commenters cite as examples the costs of in-line inspections by running smart tools through various pipeline segments or programs to detect and repair leaks on parts of the system most prone to leaks. To the extent such testing uncovers the need to incur one-time capital costs that satisfy the eligibility standards described above, such capital costs could be included in the modernization cost tracker. However, the Commission is reluctant to permit non-capital testing costs of the type described by the commenters to be recovered through a modernization cost tracker. The cost of service reflected in a pipeline's existing base rates presumably includes a projection of the pipeline's recurring costs of routine testing as part of the pipeline's O&M costs. The testing described by the commenters would appear to be a best practice for pipeline maintenance that the Commission would expect pipelines to conduct on an ongoing basis.

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[57] Section 7.3 of the Columbia Gas settlement.

[58] *See*, *e.g.*, INGAA Comments at 5-7, AGA Comments at 7.

As such it would appear difficult to distinguish any particular type of testing from the testing whose costs are already included in the O&M costs reflected in the pipeline's base rates. Therefore, while the Commission will not impose a blanket prohibition on the inclusion of such non-capital costs in a modernization cost tracker, particularly where supported by the pipeline's shippers, any proposal to include such non-capital costs in the tracker would need to demonstrate that such non-capital costs are special non-recurring costs not reflected in the O&M costs included in the pipeline's base rates and are directly related to the modernization projects whose costs are included in the modernization cost tracker. Furthermore, when determining whether a cost is a capital or non-capital cost, a pipeline's determination must be consistent with the Commission's accounting regulations and precedent.[59]

66. Some commenters also suggest that the Commission should allow eligible costs to include a portion of the capital costs incurred in a pipeline expansion project, if the project not only expands the pipeline's system but also modifies or replaces existing facilities to comply with safety or environmental regulations or make other improvements necessary for the safe and efficient operation of the pipeline.[60] The Commission

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[59] *See, e.g.*, 18 CFR pt. 201 (2014); *see also*, *Jurisdictional Public Utilities and Licensees Natural Gas Companies, and Oil Pipeline Companies, order on accounting for pipeline assessment costs*, 111 FERC ¶ 61,501 (2005).

[60] *See, e.g.*, INGAA Comments at 11-12, Columbia Gas Comments at 14-16, Berkshire Hathaway Comments at 11, Wisconsin Electric and Wisconsin Gas Comments at 9,

recognizes that some expansion projects may include modifications to a pipeline's existing system that would be eligible for recovery in a modernization cost tracker if not done in conjunction with an expansion. In such circumstances, the Commission will consider reasonable proposals for a method of cost allocation between the expansion project and the modifications eligible for inclusion in such a tracker.[61]

67. Some commenters state that the costs of modifications to compressors for the purpose of waste heat recovery should be eligible for recovery under a modernization surcharge subject to conditions,[62] while others oppose the inclusion of such costs because they assert that investments in modifications of compressors for purpose of waste heat recovery are discretionary and within control of the pipeline and should thus be subject to the normal rate review process.[63] According to the DOE, expanded use of waste heat recovery by natural gas compressors could be beneficial to overall system efficiency, and while there is a general lack of good information on the scale of heat losses from many sectors of the economy, research published in 2008 and 2009 found substantial opportunities for additional waste heat recovery investment at natural gas compressor stations. Accordingly, the Commission will consider proposals for recovery of such costs

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[61] The *Columbia Gas* settlement includes such a provision at section 7.5 of that settlement.

[62] *See*, *e.g.*, DOE Comments at 3, Wisconsin Electric and Wisconsin Gas Comments at 8, Michigan PSC Comments at 15.

[63] *See*, *e.g.*, PGC Comments at 17-18, NGSA Comments at 18-19, KCC Comments at 12.

in a modernization cost tracker proposal, subject to the standards of this Policy Statement.

68. The Commission rejects the proposals of some commenters that eligible costs be limited to those costs which the pipeline demonstrates are specifically tied to laws that have already been enacted or regulations that are currently effective. The Commission sees no reason for pipelines to wait to make needed improvements to their systems until a regulation is adopted requiring them to do so. In fact, the Department of Transportation has encouraged pipeline operators to undertake voluntary initiatives to improve pipeline safety.[64] Permitting pipelines to recover in a modernization cost tracker the costs of voluntary initiatives to improve safety, as well as minimize methane emissions, will help encourage such initiatives and thereby benefit the public. Accordingly, the Commission finds that all prudent one-time capital costs that satisfy the eligibility requirements may be included in a cost modernization tracker, regardless of whether PHMSA, EPA or some other government agency has adopted a regulation requiring the incurrence of the cost.

69. In the Proposed Policy Statement, the Commission proposed to require a pipeline proposing a modernization cost tracker to identify each capital investment to be recovered by the surcharge, the facilities to be upgraded or installed by those projects, and an upper limit on the capital costs related to each project to be included in the

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[64] United States Department of Transportation Call to Action to Improve the Safety of the Nation's Energy Pipeline System (Apr. 2011), *available at* http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/110404%20Action%20Plan%20Executive%20Version%20_2.pdf.

surcharge. INGAA requests that the Commission permit pipelines either to propose a list of eligible projects or a list of categories of future projects that would be considered eligible for recovery. Other commenters also contend that, even if the pipeline includes an upfront list of specific projects to be included in the modernization cost tracker, the Commission should permit subsequent modifications, additions, or subtractions to the listed projects. They state that this is necessary so that the tracking mechanism can adapt to changing circumstances including newly adopted regulations.

70. The Commission expects that, before the pipeline makes a tariff filing with the Commission proposing a modernization cost tracking mechanism, it will conduct a comprehensive review of its existing system to determine what capital investments it believes are needed to ensure the safe and efficient operation of its system, based on the information available to it at the time of the review. Such a review should be comparable to the comprehensive review conducted by Columbia Gas before it submitted its Settlement. The Commission continues to find that the pipeline must include in its filing a description of the facilities which its review of its system has identified as needing upgrading and/or replacement, together an upper limit on the capital costs projected to be spent and a schedule for completing the projects. This detailed information will allow for a more transparent and upfront determination of the project costs that are eligible for recovery through the tracker so as to avoid later disputes on which facilities qualify, than any description of general categories of eligible costs could. This requirement will also help ensure that normal capital or other expenditures to maintain the pipeline's system in the ordinary course of business are not eligible for recovery through a surcharge

mechanism. Consistent with this requirement, the filing should also include the accounting controls and procedures that the pipeline will use to ensure that only identified eligible costs are included in the tracker.

71. At the same time, however, the Commission recognizes the need for flexibility to make changes in the projects whose costs will be included in the tracker, after the modernization cost tracking mechanism is adopted. For example, the pipeline may discover unanticipated problems with certain facilities during the course of its modernization activities or may discover more effective solutions to existing problems. Also, changes in its shippers' utilization of its system may cause certain projects to become more critical to the safe and efficient operation of the pipeline than originally anticipated. Therefore, the Commission will be open to considering proposals to include in a modernization cost tracker a mechanism pursuant to which the parties could later modify the list of eligible projects, or the schedule for those projects, or the cost limits, based on changing priorities and other reasons.[65] The Commission also recognizes that pipelines may wish to begin modernizing their systems before PHMSA, EPA, and other Federal or state agencies complete their various ongoing regulatory initiatives. Therefore, the Commission will be open to considering proposals to add new projects to a tracking mechanism which may be required by new regulations adopted after the initial approval of the tracking mechanism or for other reasons.

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[65] *See* section 7.2 of the Columbia Gas Settlement setting forth such a mechanism.

3. Avoidance of Cost Shifting

72. The Proposed Policy Statement contemplated that a pipeline must design any proposed surcharge in a manner that will protect the pipeline's captive customers from costs shifts if the pipeline loses shippers or must offer increased discounts to retain business. The Commission suggested that one method of accomplishing this would be to establish a billing determinant floor requiring the pipeline to design the surcharge based on the greater of its actual billing determinants or the floor.

a. Comments

73. Virtually all commenters favored the avoidance of cost shifts to the pipeline's captive customers that may result from the implementation of a cost modernization surcharge. AGA, for example, supports the need to ensure that existing shippers are protected from substantial cost shifts, and comments that pipelines should be required, in consultation with their shippers, to develop appropriate measures to protect customers from cost shifts.

74. Those opposed to the Proposed Policy Statement, however, claim that the very implementation of cost modernization tracker necessarily shifts costs. MDG, for example, states that trackers shift costs to captive customers due to discounting and lost business without taking into account offsetting cost reductions, and thus even the best implementation of the Proposed Policy Statement would raise rates to captive customers unfairly. MDG claims that a billing floor will not alleviate the inherent cost shift in a policy that allows the recovery of one set of costs absent a review of all the pipeline's costs and revenues. MDG suggests that to the extent substantial pipeline capital costs are

recovered through a tracker there should be a reduction in that pipeline's return on equity to reflect the pipeline's reduced risk. The NYPSC similarly claims that while requiring a billing determinant floor for a surcharge does allow some risk to remain with the pipeline, a tracker mechanism still reduces a pipeline's risk and transfers it to shippers.

75. While NGSA, APGA, and IPAA oppose the modernization surcharge tracker, if surcharges are allowed they all support the requirement that pipelines must design the surcharge in a manner that will protect the pipeline's shippers from significant cost shifts. IPAA, NGSA, and KCC contend that at a minimum, any modernization surcharge tracker must provide for a minimum level of billing determinants to design the surcharge as in *Columbia Gas*. NGSA adds that any surcharge should apply to all throughput in the facilities and under the rate schedules impacted by the surcharge-related costs, so that an agreed upon floor on the billing determinants should be greater than the firm billing determinants (so as to include interruptible throughput, for example). AF&PA agrees that interruptible shippers should share the costs incurred through trackers to the extent that they are related to safety and environmental compliance, as these costs are not related only to firm service. IECA states costs recovered through a tracker should be limited to no more than 5 percent of the costs recovered through the pipeline's tariff.

76. AF&PA submits that if the Commission implements the Proposed Policy Statement, the policy should spread the costs as widely as possible because environmental and safety costs are incurred for all shippers. AF&PA cautions, however, that a shipper that has released certain capacity should not bear any new costs related to that capacity and recovered through the tracker.

77. NGSA argues that if shippers are already paying for eligible costs in negotiated contracts, or existing negotiated contracts prohibit recovery of these costs, they should not be subject to the modernization surcharge.

b. **Determination**

78. The third standard for approval of a cost modernization tracker adopted by the Policy Statement is that the pipeline must design any proposed surcharge in a manner that will protect the pipeline's captive customers from cost shifts if the pipeline loses shippers or must offer increased discounts to retain business beyond those reflected in their base rates.

79. As we stated in the Proposed Policy Statement, our regulations require that a pipeline's rates recover its costs based on projected units of service,[66] thereby putting the pipeline at risk for any cost under-recovery between rate cases, incentivizing the pipeline to minimize costs and maximize service. Recovery of costs approved for inclusion in a tracker, however, would be guaranteed, thereby reducing the pipeline's incentives. Moreover, a tracker mechanism can shift costs to the pipeline's captive customers. If a pipeline recovering costs through a tracker or surcharge loses shippers or must offer increased discounts to retain business, a tracker mechanism may shift the amounts previously paid by those shippers directly and automatically to the pipeline's remaining shippers. This direct cost shifting is one of the reasons the Commission has generally

[66] 18 CFR 284.10(c)(2) (2014).

disfavored trackers, namely that the cost shifting described would occur without consideration of any offsetting items that would generally be considered in a section 4 rate proceeding, and which the pipeline would normally need to justify to recover.[67]

80. Thus, as a prerequisite to the Commission allowing such a tracker, the Commission will require that the pipeline design the surcharge in a manner that will protect its shippers from cost shifts and impose on the pipeline some risk of under-recovery. As we noted in the Proposed Policy Statement, one method to accomplish this would be that adopted by Columbia Gas, namely that the pipeline agree to a billing determinant floor such that the pipeline must design the surcharge on the greater of its actual billing determinants or the established floor, and impute the revenue it would achieve by charging the maximum rate for those determinants. While the Commission found this to be a just and reasonable approach to preventing cost shifts in *Columbia Gas*, we remain open under the Final Policy to considering alternative methods of protecting the pipeline's existing customers from cost shifts if the pipeline loses customers or has to offer increased discounts of its rates to retain business during the period the modernization cost tracker is in effect.

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[67] For example, in order to recover costs associated with discounted rates the pipeline may have offered to certain shippers, the pipeline must demonstrate that the discount was required to meet competition. *Policy for Selective Discounting by Natural Gas Pipelines*, 113 FERC ¶ 61,173 (2005). In the case of a tracker, no such showing is required by the pipeline to recover the covered costs from its remaining customers.

81. The Commission believes that issues concerning how a modernization cost surcharge should be allocated among a pipeline's services and what billing determinants should be used to design the surcharge are best addressed on a case-by-case basis when each pipeline files to establish a modernization cost tracking mechanism. However, as a general matter, the Commission believes that it would be reasonable for the billing determinants used to design the surcharge to reflect a discount adjustment comparable to any discount adjustment reflected in the pipeline's base rates. Otherwise, a pipeline's modernization cost tracking mechanism would be designed in a manner that would likely lead to the pipeline under-recovering its prudently incurred modernization costs. That would be contrary to the Commission's goal of encouraging pipelines to expedite needed safety and environmental upgrades. The Commission's concern about protecting the pipeline's existing customers from cost shifts relates to cost shifts that would occur if a pipeline were permitted to true up any modernization cost under-recoveries resulting from the loss of customers after its modernization cost tracker goes into effect or a need to offer increased rate discounts to retain business after that date.[68]

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[68] The Commission notes that section 154.109(c) of the Commission's regulations (18 CFR 154.109 (2014)), requires that the pipeline's tariff contain a statement of the order in which the pipeline discounts its rates and charges. Therefore, pipelines with modernization cost surcharges will have to revise their statements of the order in which they discount rates to include the modernization cost surcharge. Treating that surcharge as the last rate component discounted would minimize the need for truing up any under-recoveries due to discounting. *See Natural Gas Pipeline Co. of America*, 70 FERC ¶ 61,317 (1995).

82. Finally, with respect to the issue of the pipeline's ability to impose a modernization cost surcharge on discounted or negotiated rate shippers, that is a contractual issue between the pipeline and its discounted or negotiated rate shippers. If a particular shipper's discount or negotiated rate agreement with the pipeline permits the pipeline to add the surcharge to the agreed-upon discounted or negotiated rate, the pipeline will be permitted to do so.[69] Otherwise, the pipeline may not impose the surcharge on a discounted or negotiated rate shipper.

4. Periodic Review of the Surcharge

83. In the Proposed Policy Statement, the Commission proposed that pipelines be required to include in a modernization cost recovery mechanism some method to allow a periodic review of whether the surcharge and the pipeline's base rates remain just and reasonable. As an example of such a method, the Commission cited the *Columbia Gas* settlement, in which the pipeline agreed to make the surcharge a temporary part of its rates (the surcharge expires automatically after five years), and included a requirement that the pipeline make a new NGA section 4 filing if it wants to continue the surcharge. However, the Commission stated it was open to other methods.

a. Comments

84. Virtually all commenters, including AGA, INGAA, NGSA, APGA, PGC, IPAA, Southern, KCC, and TVA support the proposed standard requiring a pipeline proposing a

[69] *See, e.g.*, *Sea Robin Pipeline Co., LLC*, Opinion No. 516-A, 143 FERC ¶ 61,129, at PP 85-213 (2013).

modernization cost tracker to include a method to allow a periodic rate review of the surcharge. While participants generally agreed such a condition was necessary, the recommended method and frequency of review differed.

85. Numerous commenters advocate requiring a pipeline with a cost modernization tracker to periodically file a full NGA section 4 rate case. NGSA for example, commented that a pipeline should have to file a rate case with its application for a tracker and every five years thereafter. IECA and Cities agree that a minimum 5 year rate case filing obligation is warranted. KCC and PGC espouse refresher requirements of 3 to 5 years, with a condition the pipeline not file to change rates for at least 3 years after implementation of a tracker. IPAA also supports the requirement for a full rate case refresher, and MDG suggests a rate case filing as a condition of extending any tracker beyond its initial term. Calpine commented that any surcharge have a minimum 3 year initial term that is subject to extension and renegotiation. Several commenters also advocated annual filings for pipelines to justify the projects for which costs were collected and to true-up such costs.

86. Opponents of the Proposed Policy Statement commented that a periodic review methodology was critical, though still not sufficient to justify the use of trackers. They strongly advocate a requirement that the review methodology involve a full blown NGA section 4 rate case. APGA would add the requirement that, if during the period that a surcharge mechanism is in effect, an NGA section 5 complaint is initiated against the pipeline, then the pipeline must agree to make refunds retroactive to the date of the complaint to the extent its rates are determined to be unjust and unreasonable. The

NYPSC and TVA comment that the periodic review should ensure that the surcharge does not produce earnings above authorized rates of return.

b. **Determination**

87. In this Policy Statement, the Commission adopts a policy of requiring the pipeline to include some method for a periodic review of whether the surcharge and the pipeline's base rates remain just and reasonable. Potential methods for satisfying this standard may include making the surcharge temporary and/or requiring the pipeline to file an NGA section 4 rate case to the extent it wants to extend the surcharge beyond the initial temporary term. Because we intend the Policy Statement to be flexible enough to meet the particular circumstances of each pipeline's system, we will not require that a pipeline seeking approval of a cost modernization tracker propose to file a full NGA section 4 rate case with some specified regularity and remain open to other reasonable means of accomplishing this goal.

88. Similar to the review of the pipeline's existing base rates at the beginning of the tracker proposal analysis, during the periodic review the pipeline will have to provide sufficient information to satisfy the Commission that both its base rates and the surcharge amount remain just and reasonable if the surcharge is to continue. If shippers raise any issues of material fact with respect to the continued justness and reasonableness of the pipeline's base rates or the surcharge, the Commission will establish appropriate procedures to enable resolution of those issues based upon substantial evidence on the record.

89. If a modernization cost tracking mechanism is terminated before the pipeline has fully recovered the costs included in that mechanism, the pipeline may reasonably propose in a subsequent general section 4 rate case to include the unrecovered costs in its base rates. For example, if eligible costs have been treated as rate base items in the modernization cost tracker, the undepreciated portion of those costs as of the time of the NGA section 4 rate filing could be included in the rate base used to calculate the pipeline's proposed base rates in the same manner as any other investment made between rate cases, unless the pipeline's modernization cost tracker mechanism includes some other provision concerning the treatment of unrecovered costs upon termination of the mechanism.

5. Shipper Support

90. The fifth condition proposed for a cost recovery surcharge was that the pipeline must work collaboratively with shippers to seek shipper support for any such proposal.

a. Comments

91. The vast majority of commenters support this condition but differ on the degree of shipper support the pipeline must have. On one end, INGAA suggests that the Commission could approve a proposed surcharge mechanism that it deems just and reasonable even if it lacks shipper support at the outset. NGSA and APGA, on the other hand, comment that pipeline should have the support of shippers representing 90 percent of the firm billing determinants. AGA comments that while unanimity should not be required, any approved modernization cost recovery tracking mechanism should be

established through a robust, ongoing, collaborative process between the pipeline and its shippers that has widespread shipper support.

92. IECA is more pessimistic and contends that it is completely unrealistic for any pipeline to collaborate and work with its shippers. The KCC supports collaboration among the pipeline and its shippers but comments that the condition should be expanded to include support of "interested parties," including state public utility commissions.

b. Determination

93. The fifth standard for an acceptable cost modernization surcharge adopted in this Policy Statement is that the pipeline must work collaboratively with shippers and other interested parties to seek support for any such proposal. As part of this collaborative process, pipelines should meet with their customers and other interested parties to seek resolution of as many issues as possible before submitting a modernization cost recovery proposal to the Commission. At such meetings, pipelines should share with their customers the results of their review of their systems concerning what system upgrades and improvements are necessary for the safe and efficient operations of their systems. Pipelines should also be responsive to customer requests for specific cost and revenue information necessary to determine whether their existing base rates are just and reasonable. Additionally, pipelines should provide customers and interested parties an opportunity to comment on draft tariff language setting forth their proposed modernization cost recovery mechanism.

94. As we noted in the Proposed Policy Statement, however, while we strongly encourage the pipeline to attempt to garner support for its proposal from all interested

parties, we do not intend to require unanimity of shipper support before approving a cost modernization surcharge. Nor will we establish any minimum level of shipper support required before a pipeline's proposal can be accepted. This Policy Statement will provide pipelines and their customers wide latitude to reach agreements incorporating remedies for a variety of system safety, reliability and/or efficiency issues. Despite comments that mutual collaboration is futile or impractical, the *Columbia Gas* settlement is evidence that a system-wide collaboration between a pipeline and its customers can work to produce a reasonable modernization cost recovery mechanism that benefits all sides. The Commission continues to favor settlements, and notes that the negotiation of a modernization cost tracker to address critical infrastructure issues is exactly the type of issue that lends itself to pipeline customer negotiation and agreement because it will benefit all involved. However, if a pipeline satisfies its burden under NGA section 4 to show that its proposed modernization cost recovery mechanism is just and reasonable, including showing that its proposal is consistent with the guidance herein, the Commission may accept that proposal, even if some parties oppose it.

C. Additional Questions on Which the Commission Sought Comments

95. The Commission also sought comments on several additional issues, including: accelerated amortization, reservation charge crediting, and any other factors or issues commenters believed should be included in the Policy Statement as a prerequisite for approving a modernization cost recovery mechanism.

1. Accelerated Amortization

96. In the Proposed Policy Statement, the Commission pointed out that the capital costs included in the modernization cost tracking mechanism approved in *Columbia Gas* are treated as rate base items, and thus Columbia Gas is allowed to recover a return on equity on the portion of those costs financed by equity. Consistent with the rate base treatment of those costs, they are depreciated over the life of Columbia Gas' system.[70] The Commission requested comments on whether pipelines should also be allowed to use accelerated amortization methodologies, akin to that approved by the Commission for hurricane repair cost trackers,[71] to recover the costs of any facilities installed pursuant to a modernization cost recovery mechanism. The Commission stated that under such a methodology the costs would not be included in the pipeline's rate base, and the pipeline would not recover any return on equity with respect to the costs financed by equity. Instead, the pipeline would only be allowed to recover the interest necessary to compensate it for the time value of money.

a. Comments

97. The Commission received a range of comments on this issue. Wisconsin Electric and Wisconsin Gas support using an accelerated amortization of costs of facilities

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[70] *Columbia Gas*, 142 FERC ¶ 61,062 at P 9.

[71] *See, e.g.*, *Sea Robin Pipeline Co., LLC*, Opinion No. 516, 137 FERC ¶ 61,201, at PP 16-65 (2011), *reh'g den,* Opinion No. 516-A, 143 FERC ¶ 61,129 at PP 17-80.

installed pursuant to eligible modernization projects.[72] IECA also supports accelerated amortization for safety and environmental compliance costs but argues for the amortization to be set at a rate that would require the pipeline to come back for a rate case in five years.[73] NGSA argues that accelerated amortization, with carrying costs, over a specified term, is the most appropriate rate design structure for recovering all approved costs under a tracker, with the length of any amortization period determined on a case-by-case basis, dependent upon the level of costs.[74] NGSA argues that it is not appropriate for the pipeline to earn a rate of return and taxes on these types of tracked expenditures because these would be incremental costs, with guaranteed cost recovery (i.e., no risk on the pipeline) under the tracker.[75]

98. NCUC opposes the proposal on the grounds that the accelerated amortization allowed for storm damage repair costs would be inappropriate for modernization costs, because accelerated amortization would raise intergenerational cross –subsidization issues and could magnify rate shock. Similarly, Laclede opposes recovery of capital

[72] Wisconsin Electric and Wisconsin Gas Comments at 14.

[73] IECA Comments at 21.

[74] NGSA Comments at 12-13, 24.

[75] NGSA Comments at 24.

costs through accelerated amortization methodologies, and argues that any costs not recovered through tracker rates should be rolled into rate base.[76]

99. CAPP recommends that the consultative process by which individual pipelines formulate their respective proposals include the opportunity for stakeholders to evaluate the preferred accelerated amortization methodology.[77] Calpine also does not object to allowing pipelines and their shippers to consider accelerated amortization methodologies as part of their modernization surcharge negotiations.[78] Columbia Gas states the Commission should consider permitting pipelines to use accelerated amortization methodologies but allow pipelines and their customers the discretion to negotiate the appropriate method of amortization, which should include the possibility of earning a reasonable return.[79] INGAA requests that the Commission provide each pipeline that

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[76] Laclede Comments at 20. See also PGC Comments at 19-20 (PGC opposes accelerated amortization for modernization upgrades, contending that it will only give pipelines additional latitude to increase their profits.).

[77] CAPP Comments at 9. *See also* KCC Comments at 24, 27 (KCC does not oppose extension of the use of accelerated amortization methodologies for recovering approved costs under a modernization cost tracker if the costs subject to accelerated amortization are not included in rate base, and a pipeline is not able to recover any return on equity for costs financed by equity).

[78] Calpine Comments at 30.

[79] Columbia Gas Comments at 34. *See also* APGA comments at 22 (to the extent the Commission permits pipelines to implement the modernization cost tracker, customers of the requesting pipeline should make the decision as to whether rate base treatment or some sort of reasonable amortization period works best for them under the circumstances).

proposes a modernization cost tracker the ability to propose either accelerated amortization methodologies or depreciation over the life of the facilities, because each pipeline faces different competitive circumstances.[80]

b. **Determination**

100. The Commission agrees with the commenters who suggested that pipelines should be allowed to negotiate with their customers concerning whether modernization costs should be treated as (1) a rate base item to be depreciated over the life of the pipeline with the pipeline recovering a return on equity on the portion of those costs financed by equity together with associated income taxes or (2) a non-rate base item to be amortized over a shorter period with the pipeline recovering the interest necessary to compensate it for the time value of money but no return on equity or associated income taxes. These two cost recovery options have varying advantages and disadvantages. For example, rate base treatment is likely to lead to a lower per unit daily or monthly surcharge, because it spreads the pipeline's recovery of the costs over a substantially longer period. Such lower per unit rates should help mitigate any rate shock. However, over the long run, rate base treatment is likely to be more expensive for shippers, because the surcharge will be in effect for a longer period and the return on the equity portion of the rate base will be greater than the interest rate on the costs being amortized.[81] In light of these varying

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[80] INGAA Comments at 19-20.

[81] *See* Opinion No. 516-A, 143 FERC ¶ 61,129 at PP 35-56.

advantages and disadvantages, the Commission will permit pipelines and their shippers to negotiate which recovery method is appropriate for each pipeline, based upon the circumstances of its system.

2. Reservation Charge Crediting

101. The Commission requires pipelines to provide full reservation charge credits for outages of primary firm service caused by non-*force majeure* events, where the outage occurred due to circumstances within the pipeline's control, including planned or scheduled maintenance.[82] The Commission also requires the pipeline to provide partial reservation charge credits during *force majeure* outages, so as to share the risk of an event for which neither party is responsible.[83] Partial credits may be provided pursuant to: (1) the No-Profit method under which the pipeline gives credits equal to its return on equity and income taxes starting on Day 1; or (2) the Safe Harbor method under which the pipeline provides full credits after a short grace period when no credit is due

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[82] *See, e.g.*, *Tennessee Gas Pipeline Co.*, Opinion No. 406, 76 FERC ¶ 61,022 (1996), *order on reh'g*, Opinion No. 406-A, 80 FERC ¶ 61,070 (1997), *as clarified by*, *Rockies Express Pipeline LLC*, 116 FERC ¶ 61,272, at P 63 (2006) (*Rockies Express I*), and *North Baja Pipeline, LLC*, 109 FERC ¶ 61,159 (2004), *reh'g denied*, 111 FERC ¶ 61,101 (2005), *aff'd*, *North Baja Pipeline, LLC v. FERC*, 483 F.3d 819 (D.C. Cir. 2007) (*North Baja v. FERC*).

[83] The Commission has defined *force majeure* outages as events that are both unexpected and uncontrollable. Opinion No. 406, 76 FERC at 61,088. *North Baja v. FERC*, 483 F.3d at 823.

(i.e., 10 days or less).[84] The Commission permits pipelines to reflect the recurring cost of providing reservation charge credits during non-*force majeure* events in their rates.[85]

102. In the Proposed Policy Statement, the Commission stated that the pipelines' performance of facility upgrades and replacements required by recent legislative and other actions to address pipeline efficiency, safety, and environmental concerns may result in disruption of primary firm service. The Commission also cited recent Commission orders clarifying that one-time outages of primary firm service, if necessary to comply with government orders, may be treated as *force majeure* outages, for which only partial reservation charge credits are required.[86] The Commission requested comments on whether it should make any adjustments to its current reservation charge crediting policy in light of the Proposed Policy Statement.[87]

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[84] The Commission has also stated that pipelines may use some other method that achieves equitable sharing reasonably equivalent to the two specified methods.

[85] *See, e.g., Northern Natural Gas Co.*, 137 FERC ¶ 61,202, at P 36 (2011), *order on reh'g and compliance*, 141 FERC ¶ 61,221, at PP 45-50 (2012) (*Northern*). The Commission has stated this could be accomplished by a reduction in the billing determinants used to design a pipeline's rates or by including the cost of the full reservation charge credits as an item in the pipeline's cost of service. *Gulf South Pipeline Co., LP*, 144 FERC ¶ 61,215, at P 34 (2013) (*Gulf South*).

[86] *See, e.g., TransColorado Gas Transmission Co. LLC*, 144 FERC ¶ 61,175 (2013) (*TransColorado*); *Gulf South*, 144 FERC ¶ 61,215.

[87] Proposed Policy Statement at P 34.

a. Comments

103. The pipeline industry generally advocated that the Commission modify its policy requiring pipelines to pay reservation charge credits starting on Day One for disruption of primary firm service required by either voluntary or mandatory system improvements eligible for surcharge cost recovery. They contend that the pipeline modernization programs under consideration are not representative of pipeline mismanagement and are significantly different than conducting routine maintenance, [88] and thus the Commission should not impose any reservation charge crediting requirement or at least treat any resulting outages as *force majeure* events requiring only partial reservation charge credits. INGAA also argued that the Commission should explicitly provide that costs to comply with other statutory and regulatory requirements, such as hydrostatic testing to confirm maximum pressure levels, are not subject to reservation charge credits.[89] INGAA also argues, however, that to the extent that a pipeline must pay reservation charge credits for a service outage required by a system improvement eligible for surcharge cost recovery, it should be permitted to recover such crediting costs through the modernization cost recovery tracker.[90] Columbia Gas urges the Commission to extend its

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[88] INGAA Comments at 15-18.

[89] INGAA Comments at 18.

[90] INGAA Comments at 18-19. KM Comments at 8 (agreeing with INGAA that reservation charge crediting not apply for interruptions of firm service when pipelines are performing either voluntary or mandatory maintenance to improve safe and efficient operations.).

policy of granting partial reservation charge credits to outages due to construction of eligible modernization projects.[91]

104. Shippers and various state commissions encourage the Commission to require pipelines with modernization cost trackers to provide full reservation charge credits during periods that the pipeline must interrupt primary firm service to replace or install eligible facilities under the provisions of the modernization tracker.[92] NCUC states that full reservation charge credits will provide pipelines a stronger incentive to schedule any necessary construction or modification of facilities required to comply with any new regulations in an efficient manner.[93] Likewise, while PGC, APGA, IPAA, and NGSA oppose the implementation of modernization cost trackers, they request that to the extent the Commission chooses to allow their implementation, it modify its reservation charge crediting policy to require pipelines with modernization cost trackers to provide full

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[91] Columbia Gas Comments at 36. Boardwalk suggests the Commission should modify its current reservation charge crediting policy to allow for a more equitable balancing of the risks between pipelines and their customers for service disruptions caused by testing, repair or replacement activities taken to comply with the new PHMSA rules. (Boardwalk Comments at 24.).

[92] Michigan PSC Comments at 20. IECA and American Midstream do not support changes to the existing reservation charge credits. IECA Comments at 21; American Midstream Comments at 8.

[93] NCUC Comments at 34.

reservation charge credits to firm customers during any period that the pipeline must interrupt primary firm service to replace or install eligible facilities.[94]

b. Determination

105. The Commission's current reservation charge crediting policies require pipelines to provide some level of reservation charge credits whenever the pipeline is unable to schedule reserved primary firm service because of a government action. The level of credits to be provided turns on whether the government action is considered a *force majeure* event.[95]

106. The Commission has defined *force majeure* outages as events that are both "unexpected and uncontrollable." In *TransColorado*[96] and *Gulf South*,[97] the Commission clarified the basic distinction as to whether outages resulting from governmental actions are *force majeure* or non-*force majeure* events. The Commission found that outages necessitated by compliance with government standards concerning the regular, periodic maintenance activities a pipeline must perform in the ordinary course of business to ensure the safe operation of the pipeline, including PHMSA's integrity management

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[94] PGC Comments at 20, APGA Comments at 22, IPAA Comments at 3, 26-27, NGSA Comments at 13, 25.

[95] *Tennessee Gas Pipeline Co., L.L.C.*, 139 FERC ¶ 61,050, at PP 80-82 (2012). *Texas Eastern Transmission, LP*, 149 FERC ¶ 61,143, at PP 121-123 (2014).

[96] *TransColorado,* 144 FERC ¶ 61,175 at PP 35-43.

[97] *Gulf South*, 144 FERC ¶ 61, 215 at PP 31-34.

regulations, are non-*force majeure* events requiring full reservation credits. Outages resulting from one-time, non-recurring government requirements, including special, one-time testing requirements after a pipeline failure, are *force majeure* events requiring only partial crediting.

107. In *Gulf South*, the Commission explained that this distinction is reasonable for two reasons. First, the pipeline is likely to have greater discretion as to when it performs regular, periodic maintenance on particular pipeline segments than when the government orders special one-time testing, for example after a pipeline failure. Thus, regular, periodic maintenance required by government regulation may be considered reasonably within the control of the pipeline and expected, in contrast to one-time, non-recurring government requirements, which the pipeline may have to implement within a short timeframe. Second, the recurring costs of regular, periodic maintenance performed in the ordinary course of business may be included in a pipeline's rates in a general NGA section 4 rate case, whereas one-time, non-recurring costs are generally not eligible for inclusion in a pipeline's rates in a section 4 rate case. The Commission explained that because the full crediting policy is premised on the ability of the pipeline to recover the costs associated with that policy through its rates, it follows that eligibility for such cost recovery is an important factor in distinguishing between the types of government testing and maintenance requirements that trigger the full crediting requirement and those that

only trigger a partial crediting requirement.[98] Thus, under *TransColorado* and *Gulf South*, outages resulting from one-time non-recurring government requirements that (1) are not part of the pipeline's routine, periodic maintenance programs and (2) provide the pipeline little discretion as to when the outage occurs, qualify as *force majeure* events.

108. Against this background, we recognize that facility upgrade and replacement projects whose costs would be eligible for recovery under a modernization tracker do not lend themselves easily to the governmental action *force majeure*/non-*force majeure* distinction described above. On the one hand, such projects do not constitute routine periodic maintenance of the type for which the Commission requires full reservation charge credits; in fact, the Commission has held that such routine maintenance costs are not eligible for inclusion in a modernization cost tracker. Moreover, because each project constitutes a one-time, non-recurring event, any reservation charge credits provided by the pipeline would not be a recurring cost eligible for recovery in a pipeline's NGA section 4 general rate case. On the other hand, pipelines will likely have considerable discretion as to the timing of when they perform each project, with projects likely to be scheduled and performed over a multi-year period. Therefore, the projects are not unexpected in the sense ordinarily required for treatment as a *force majeure* event.

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[98] *Texas Eastern*, 149 FERC ¶ 61,143 at P 123.

109. In these circumstances, the Commission believes the issue of reservation charge credits for projects included in a modernization cost tracker is best addressed, at least initially, on a case-by-case basis in each proceeding in which a pipeline proposes such a tracker. In its filing to establish a tracker, the pipeline should state the extent to which it anticipates that any particular project will disrupt primary firm service, explain why it expects it will not be able to continue to provide firm service, and describe what arrangements the pipeline intends to make to mitigate the disruption or provide alternative methods of providing service. To the extent a pipeline incurs costs to make temporary alternative arrangements to provide service while a project is under construction, such as through temporary line bypasses or natural gas tankers, such costs may be considered for inclusion in the tracker. However, if a modernization project unavoidably causes an outage of primary firm service, the Commission believes that pipelines should provide some relief from the payment of reservation charge to shippers directly affected by that outage. To the extent the pipeline provides such shippers full reservation charge credits, the Commission would consider proposals for the pipeline to recover such costs through the tracker, consistent with the Commission's policy that pipelines may recover the costs of full reservation charge credits in rates. Alternatively, the Commission would consider partial reservation charge crediting methods tailored to the circumstances of the projects included in the tracker.

3. <u>Other Issues</u>

110. The Commission sought comments on any other issues or factors interested parties though the Commission should consider for inclusion in the Policy Statement as a

prerequisite for approving a modernization cost recovery mechanism.[99] The Commission received comments on a variety of proposals on additional items to include in the Policy Statement, including return on equity, and formula rates.

a. Return on Equity

111. EPMCG, MDG, APGA and the NYPSC argue that if the portion of capital investment subject to a tracker is significant to the pipeline's rate base, then the Commission should adjust downward the pipeline's allowed rate of return on equity to reflect the decreased risk that the pipeline has to recover its cost of investment given the existence of a tracker.[100] IPAA and NGSA also argue that the plant facilities to be constructed pursuant to the proposed modernization surcharge should not be eligible to earn a rate of return and taxes, because these facilities are not included in a pipeline's rate base through an NGA general section 4 rate filing.[101]

112. The Commission will not mandate an automatic ROE reduction for pipelines that have a modernization surcharge or tracker. We do agree, however, that a modernization tracker or surcharge could be a factor that is considered as to the appropriate level of a

[99] Because the Policy Statement would address issues pertaining to the Commission's review of natural gas rate filings, the statement is categorically excluded from the requirements of the National Environmental Policy Act (NEPA), thus neither an environmental assessment nor an environmental impact statement is required. *See* 18 CFR 380.4(a)(25) (2014).

[100] EPMCG Comments at 43, APGA Comments at 22-23, and MDG Comments at P 2, NYPSC Comments at P 1-3.

[101] IPAA Comments at 3, 26, NGSA Comments at 13.

pipeline's ROE. We agree that considerations of return on equity reduction may be considered during shipper and pipeline negotiations.

b. Formula Rates

113. APGA argues that, if the Commission wants a tracker mechanism that ensures just and reasonable rates, it must apply to the pipeline's entire cost of service, similar to the transmission formula rates that the Commission has approved for electric utilities under the Federal Power Act.[102] APGA states that the advantage of such formula rates, most of which allow projected capital additions to be included in a given year's formula rate and are trued up for actuals, are that the electric utilities are assured timely recovery of capital outlays and customers are assured that rates are premised on full and updated cost-of-service data, including throughput, so that the over-recovery problem associated with tracker mechanisms applicable to only a portion of the pipeline's cost of service is obviated.

114. The Commission will not adopt APGA's proposal. In the instant proceeding the Commission is adopting a policy permitting pipelines to recover a limited category of one-time costs through a tracker mechanism, namely the costs of making needed upgrades for the safe and efficient operation of the pipeline. For the reasons discussed above, the Commission can permit this limited exception to our general policy of requiring pipelines to design their rates based on projected units of service, without

[102] APGA Comments at 11-12.

undercutting the benefits of that policy of providing pipeline an incentive to minimize costs and maximize the service they provide. APGA's proposal to require pipelines to track all changes in their cost of service, on the other hand, would eliminate both those incentives.

c. Transparency

115. Wisconsin Electric and Wisconsin Gas propose that the Commission include additional transparency measures to require pipelines to identify and track all costs associated with each project or project phase and file a quarterly summary report detailing the progress and completion of the projects included in the tracker. In addition, Wisconsin Electric and Wisconsin Gas state existing service customers should have the right to validate the premise and the projected results of a pipeline's modernization and to audit costs. Finally, Wisconsin Electric and Wisconsin Gas submit that the pipeline should be required to quantify current costs that are reduced or avoided as a result of the and net those costs out of the total eligible cost.[103]

116. The Commission will not adopt a policy requiring pipelines to submit reports on its projects based on any particular schedule, or specify the content of those reports in this Policy Statement. These are issues that should be addressed in the individual proceedings where each pipeline proposes a modernization cost tracker. Likewise, the validation and quantification of costs and projects may be negotiated. Nevertheless, a pipeline's

[103] Wisconsin Electric and Wisconsin Gas Comments at 15.

compliance with its tariff to implement a modernization cost tracker may be subject to scrutiny through a Commission audit.

d. **Proposed Certificate Policy Modifications**

117. Columbia Gas proposes that the Commission undertake a review and implement a "fast track" processing for NGA 7(c) projects that involve replacement of older vintage pipelines, like bare steel replacement, or involve an important public safety aspect.[104] Columbia Gas also comments that not all pipeline facilities are appropriate for replacement or upgrade because some facilities may have reached or are close to the end of their useful life. Therefore, Columbia states a full replacement of certain facilities may be cost prohibitive, even with a tracker, because shippers on the facilities are unwilling or unable to support the costs of the replacement.[105] Similarly, Boardwalk states abandonment of facilities that will no longer be economic to operate because of substantial costs necessary to modify the facilities in order to achieve compliance with new requirements may be the best option and in the public interest.[106]

118. Columbia Gas' and Boardwalk's proposals are beyond the scope of this Policy Statement, and thus we will not address them here.

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[104] Columbia Gas Comments at 37.

[105] Columbia Gas Comments at 21.

[106] Boardwalk Comments at 18-19.

III. Information Collection Statement

119. The collection of information discussed in the Policy Statement is being submitted to the Office of Management and Budget (OMB) for review under section 3507(d) of the Paperwork Reduction Act of 1995[107] and OMB's implementing regulations.[108] OMB must approve information collection requirements imposed by agency rules.

120. The Commission solicits comments from the public on the Commission's need for this information, whether the information will have practical utility, the accuracy of the burden estimates, recommendations to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques. The burden estimates are for implementing the information collection requirements of this Policy Statement. The Commission asks that any revised burden estimates submitted by commenters include the details and assumptions used to generate the estimates.

121. The collection of information related to this Policy Statement falls under FERC–545A (Gas Pipeline Rates: Rate Change (Non-Formal), Modernization Tracker).[109] The following estimate of reporting burden is related only to this Policy Statement.

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[107] 44 U.S.C. 3507(d) (2012).

[108] 5 CFR 1320.

[109] The information collection requirements in this Policy Statement would normally be included in FERC-545 (OMB Control No. 1902-0154) which covers rate change filings made by natural gas pipelines, including tariff changes. However, another item is pending OMB review under FERC-545, and only one item per OMB Control

(continued ...)

122. Public Reporting Burden: The estimated annual burden and cost follow.

Number can be pending review at OMB at a time. Therefor in order to submit this timely to OMB, we are using a temporary collection number (FERC-545A) to cover the requirements implemented in PL15-1-000.

FERC-545A, as implemented in Policy Statement in PL15-1-000					
	Number of Respondents[110] **(1)**	**Number of Responses per Respondent (2)**	**Average Burden Hours Per Response (3)**	**Total Annual Burden Hours (1)x(2)x(3)**	**Total Annual Cost ($)**[111] **[rounded]**
provide information to shippers for any surcharge proposal, and prepare modernization cost tracker filing[112]	3	1	750	2,250	$147, 578

[110] An estimated 165 natural gas pipelines (Part 284 program) may be affected by this Policy Statement. Of the 165 pipelines, Commission staff estimates that 3 pipelines may choose to submit an application for a modernization cost tracker per year.

[111] The most recent hourly wage figures are published by the Bureau of Labor Statistics, U.S. Department of Labor, *National Occupational Employment and Wage Estimates, United States,* Occupation Profiles, May 2014 (available 4/1/2015) at http://www.bls.gov/oes/home.htm, and the benefits are calculated using BLS information, at http://www.bls.gov/news.release/ecec.nr0.htm.

The average hourly cost (salary plus benefits) to prepare the modernization cost tracker filing is $65.59. It is the average of the following hourly costs (salary plus benefits): manager ($77.93, NAICS 11-0000), Computer and mathematical ($58.17, NAICS 15-0000), Legal ($129.68, NAICS 23-0000), Office and administrative support ($39.12, NAICS 43-0000), Accountant and auditor ($51.04, NAICS 13-2011), Information and record clerk ($37.45, NAICS 43-4199), Engineer ($66.74, NAICS 17-2199), Transportation, Storage, and Distribution Manager ($64.55, NAICS 11-3071).

The average hourly cost (salary plus benefits) to perform the periodic review is $67.04. It is the average of the following hourly costs (salary plus benefits): manager ($77.93, NAICS 11-0000), Legal ($129.68, NAICS 23-0000), Office and administrative support ($39.12, NAICS 43-0000), Accountant and auditor ($51.04, NAICS 13-2011), Information and record clerk ($37.45, NAICS 43-4199).

[112] The pipeline's modernization cost tracker filing is expected to include information to:

(continued ...)

perform periodic review and provide information to show that both base rates and the surcharge amount remain just and reasonable	3	0.60[113]	350	630	$42,235

123. Title: FERC-545A (Gas Pipeline Rates: Rate Change (Non-Formal), Modernization Tracker).

124. Action: Proposed information collection

125. OMB Control No.: To be determined

- demonstrate that its current rates are just and reasonable and that proposal includes the types of benefits that the Commission found maintained the pipeline's incentives for innovation and efficiency;
- identify each capital investment to be recovered by the surcharge, the facilities to be upgraded or installed by those projects, and an upper limit on the capital costs related to each project to be included in the surcharge, and schedule for completing the projects;
- establish accounting controls and procedures that it will utilize to ensure that only identified eligible costs are included in the tracker;
- include method for periodic review of whether the surcharge and the pipeline's base rates remain just and reasonable; and
- state the extent to which any particular project will disrupt primary firm service, explain why it expects it will not be able to continue to provide firm service, and describe what arrangements the pipeline intends to make to mitigate the disruption or provide alternative methods of providing service.

[113] Based on the Columbia case, we estimate that a review may be required every 5 years, triggering the first pipeline reviews to be done in Year 6 (for the pipelines which applied and received approval in Year 1).

126. Respondents: Business or other for profit enterprise (Natural Gas Pipelines).

127. Frequency of Responses: Ongoing.

128. Necessity of Information: The Commission is establishing a policy to allow interstate natural gas pipelines to seek to recover certain capital expenditures made to modernize system infrastructure through a surcharge mechanism, subject to certain conditions. The information that the pipeline should share with its shippers and submit to the Commission is intended to ensure that the resulting rates are just and reasonable and protect natural gas consumers from excessive costs

129. Internal Review: The Commission has reviewed the guidance in the Policy Statement and has determined that the information is necessary. These requirements conform to the Commission's plan for efficient information collection, communication, and management within the natural gas pipeline industry. The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

130. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873].

131. Comments concerning the collection of information and the associated burden estimate should be sent the Commission by [insert 60 days from publication in the Federal Register] .

IV. Document Availability

132. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington DC 20426.

133. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

134. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

V. Effective Date and Congressional Notification

135. This Policy Statement will become effective October 1, 2015.

The Commission orders:

The Commission adopts the Policy Statement and supporting analysis contained in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Note: The following appendix will not appear in the *Code of Federal Regulations.*

Appendix - List of Commenters

American Forest & Paper Association
American Gas Association
American Midstream, LLC
American Public Gas Association
Beatrice Gahman
Berkshire Hathaway Energy Company
Boardwalk Pipeline Partners, LP
Calpine Corporation
Canadian Association of Petroleum Producers
CenterPoint Energy Resources Corp.
Clean Air Task Force
Columbia Gas Transmission, LLC
Deep Gulf Energy LP
El Paso Municipal Customer Group
Elizabeth Balogh
Energy XXI Ltd.
Environmental Defense Fund, Conservation Law Foundation and the Sustainable FERC Project
Ernest J. Moniz, Secretary. United States Department of Energy
Fairfax Hutter
Helis Oil and Gas Company, L.L.C.
Independent Oil & Gas Association of West Virginia, Inc.
Independent Petroleum Association of America
Indicated Shippers
Industrial Energy Consumers of America
Interstate Natural Gas Association of America
Kansas Corporation Commission
Karen Feridum
Kinder Morgan Interstate Pipelines
Laura Pritchard
Michigan Public Service Commission
Missouri Public Service Commission
Municipal Defense Group
Natural Gas Supply Association
New York Public Service Commission
Norman W. Torkelson
North Carolina Utilities Commission
Patriots Energy Group
Pipeline Safety Coalition

Process Gas Consumers Group and the American Forest & Paper Association
Secretary of Energy
Southern Company Services
Southern Star Central Gas Pipeline, Inc.
Tenneesse Valley Authority
Teresa Ecker
The Laclede Group, Inc.
U.S. Department of Energy
U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration
WBI Energy Transmission, Inc.
Western Tennessee Municipal Group
Wisconsin Electric Power Company and Wisconsin Gas LLC
Xcel Energy Companies

Resolution Encouraging Natural Gas Line Investment and the Expedited Replacement of High-Risk Distribution Mains and Service Lines

WHEREAS, NARUC and its members have long focused on pipeline safety, led by the Committee on Gas, established in 1964, the Staff Subcommittee on Pipeline Safety, the Task Force on Pipeline Safety, and the newly created Subcommittee on Pipeline Safety; *and*

WHEREAS, NARUC enjoys a close working relationship with the National Association of Pipeline Safety Representatives (NAPSR), a national organization representing the State pipeline inspection workforce throughout the country; *and*

WHEREAS, NAPSR in November 2011 released an exhaustive compendium of State pipeline safety programs which exceed the minimum federal standards States must meet in order to receive funding from the U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA); *and*

WHEREAS, NARUC and the Committee on Gas maintain a strong cooperative partnership with PHMSA, which is essential to ensure State and federal safety regulators work closely on pipeline safety; *and*

WHEREAS, More than two million miles of natural gas distribution pipelines crisscross the United States, connecting homes and businesses with one of America's most important energy resources. These pipelines are the safest, most reliable and cost-effective way to transport this essential fuel across the country; *and*

WHEREAS, The safe and reliable delivery of natural gas to homes and businesses and its use in providing new products and services is vital to the U.S. and of paramount importance to members of NARUC; *and*

WHEREAS, By law, the utilities are charged with knowing the location, material, age and condition of their systems. Developing essential data to evaluate the integrity of the systems is the foundation for any determination over what regulators need to fund in rates, as well as what rate recovery methodology best suits a particular case; *and*

WHEREAS, Many States and distribution utilities are undergoing significant pipeline replacement programs to replace aging pipe; *and*

WHEREAS, Many distribution companies are being proactive about replacing their aging pipelines through a risk-based approach focusing on prioritizing safety, asset replacement, and rate impact; *and*

WHEREAS, Alternative rate-recovery mechanisms may help expedite the replacement and expansion of the pipeline systems by promoting more timely rate recovery for investments in infrastructure, safety and reliability; *and*

WHEREAS, Alternative rate recovery mechanisms may help eliminate near-term financial barriers of traditional ratemaking policies such as "regulatory lag" and promote access to lower-cost capital; *and*

WHEREAS, The adoption of alternative rate policies may be very effective for advancing critical safety and reliability infrastructure upgrades, *and*

WHEREAS, Notwithstanding the positive advances in innovative ratemaking and proactive remediation by many distribution companies, utility management bears ultimate responsibility for their respective systems and should seek to work, in ways permissible under their respective State rules and law, collaboratively with Commissioners and/or Commission staff to prioritize asset replacement based upon asset risk, available technology, public safety risk, rate impact, *and*

WHEREAS, Ensuring pipeline safety is about more than just replacement and cost recovery. It is also about effective communication, enforcement, risk sharing, and establishing a long range strategic plan that ensures a safe and reliable gas pipeline system; *and*

WHEREAS, As evidenced in the NAPSR 2011 Compendium, State commissions and inspectors are best suited to determine how best to finance system improvements because each State is different and the needs and financial circumstances of each utility system are unique; *now, therefore be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at the 2013 Summer Committee Meetings, in Denver, Colorado, encourages regulators and industry to consider sensible programs aimed at replacing the most vulnerable pipelines as quickly as possible along with the adoption of rate recovery mechanisms that reflect the financial realities of the particular utility in question; *and be it further*

RESOLVED, That State commissions should explore, examine, and consider adopting alternative rate recovery mechanisms as necessary to accelerate the modernization, replacement and expansion of the nation's natural gas pipeline systems, *and be it further*

RESOLVED, That NARUC encourages its members to reach out to PHMSA, NAPSR, industry, State and local officials, and the general public about pipeline safety and replacement programs.

Sponsored by the Committee on Gas and the Committee on Critical Infrastructure
Adopted by the NARUC Board of Directors July24, 2013

American Gas Association

AGA's Commitment to Enhancing Safety: Revised February 2016

AGA and its members are dedicated to the continued enhancement of pipeline safety. As such, we are committed to proactively collaborating with federal and state regulators, public officials, emergency responders, excavators, consumers, safety advocates and the public to continue improving the industry's longstanding record of providing natural gas service safely, reliably and efficiently to 177 million Americans. AGA and its members support the development of reasonable regulations to meet federal objectives and National Transportation Safety Board recommendations.

Below are voluntary actions that are being taken by AGA or individual operators to help ensure safe and reliable operation of the nation's 2.5 million miles of natural gas pipeline which span all 50 states with diverse geographic and operating conditions. AGA and its individual operators recognize the significant role that their state regulators or governing bodies play in supporting and funding these actions.

It is the consensus of AGA members that the actions listed below enhance safety, gas utility operations, and reduce greenhouse gas emissions when implemented as an integral part of each operator's specific safety programs. However, both the need to implement and the timing of implementation of these actions will vary with each operator. Each operator will need to evaluate the actions in light of system and geographic variables, the operator's independent integrity assessment, risk analysis and mitigation strategy and what has been deemed reasonable and prudent by their state regulators. Therefore, not all of these recommendations will be applicable to all operators.

Building Pipelines for Safety

Construction

- Expand requirements of the Operator Qualification rule to include new pipeline construction.
- Review established pipeline construction oversight procedures to ensure adequacy and compliance with those procedures.
- Implement industry leading practices when installing new pipelines to help prevent damage to other facilities.

Emergency Shutoff Valves

- Support a risk based approach to the installation of automatic and/or remote control isolation valves where technically and operationally feasible on newly constructed or entirely replaced transmission lines.
- Work with regulatory agencies and policy makers to develop guidelines for consideration of automatic and/or remote control isolation valves on transmission lines that are in service.
- Expand the use of excess flow valves (EFVs) to new and fully replaced branch services, small multi-family facilities, and small commercial facilities where technically and operationally feasible.

Operating Pipelines Safely

Integrity Management

- Advance integrity management programs and principles to mitigate system specific risks. This includes operational activities, repair, replacement or rehabilitation of pipelines and associated facilities where it will most improve safety and reliability.
- Collaborate with stakeholders to develop and promote effective cost-recovery mechanisms to support pipeline assessment, repair, rehabilitation, and replacement programs.
- Develop industry guidelines for data management to advance data quality and knowledge related to pipeline integrity.
- Support development of processes and guidelines that enable the tracking and traceability of new pipeline components.

Excavation Damage Prevention

- Support strong enforcement of the 811 – Call Before You Dig program, and advocate for the reduction of excavator exemptions within state damage prevention laws.
- Improve engagement between the operator and excavators on the need to call before digging to reduce excavation damage.

Physical and Cybersecurity/System Controls

- Take actions that help strengthen the physical and cybersecurity of the gas utility industry.
- Enhance system monitoring and control of gas systems.

Enhancing Pipeline Safety

Safety Knowledge Sharing

- Expand the voluntary national Peer Review Program to allow companies to observe their peers, identify what is working well, identify opportunities to improve, and share leading practices.
- Evaluate the work of other industries to improve safety. Identify and implement models that will assist in enhancing safety and encourage knowledge exchange among operators, contractors, government and the public.

Workforce Development

- Collaborate with industry, government, educational institutions and labor groups to develop solutions to address the need for a qualified, diverse workforce.

Public Awareness and Emergency Response

- Evaluate methods to effectively communicate with public officials, excavators, consumers, safety advocates and the public about the presence of pipelines. Implement tested and proven communication methods to enhance those communications.
- Partner with emergency responders to share information and improve emergency response coordination.

Pipeline Planning Engagement

- Work with a coalition of Pipelines and Informed Planning Alliance (PIPA) Guidance stakeholders to increase awareness of risk based land use options and adopt existing PIPA recommended best practices.

Advancing Technology Development

- Increase investment, continue participation, and support research, development and deployment of technologies to improve safety.

Building Pipelines for Safety

Construction

- Maintain a clearinghouse on effective cost-recovery mechanisms that states have used to fund infrastructure repair, replacement and rehabilitation projects.

Emergency Shutoff Valves

- Install EFVs on new and fully replaced branch services, small multi-family facilities, and small commercial facilities where technically and operationally feasible.

Operating Pipelines Safely

Integrity Management

- Advocate programs to accelerate the risk-based repair, rehabilitation and replacement of pipelines.
- Support development of processes and guidelines that enable tracking and traceability of pipeline components.
- Continue the Plastic Pipe Database Committee's work to collect and analyze plastic material failures.
- Incorporate systems and/or processes to reduce human error.
- Promote the use of API RP 1171, *Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs*, and API RP 1170, *Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage. This includes teleconferences, workshops and roundtables to share lessons learned from companies voluntarily adopting the recommended practices,*

Excavation Damage Prevention

- Use a risk-based approach to improve excavation monitoring.
- Support the Common Ground Alliance, the use of 811 and other damage prevention initiatives through outreach, education, intervention and enforcement.
- Influence and/or support state legislation to strengthen damage prevention programs.
- Encourage participation in One-Call by all underground operators and excavators.

Physical and Cybersecurity/System Controls

- Participate in a Downstream Natural Gas Information Sharing & Analysis Center (DNG ISAC).
- Conduct cybersecurity vulnerability assessments.
- Collaborate with government to develop and implement guidance, such as *DOE ONG-C2M2, DOE Energy Sector & TSA Transportation Sector Framework Implementation Guidance* and NIST *Energy Sector Cybersecurity Framework Implementation Guidance*
- Create industry guidance and hold events to strengthen the physical and cybersecurity of the natural gas infrastructure, including the *Natural Gas Utility Threat Analysis Elements & Mitigations Guidance, Cybersecurity Procurement Language Guidance*, an AGA Energy Delivery Cybersecurity Executive Summit, cyber threat analysis workshops, insider threat workshops, workshops on the Oil and Natural Gas Cybersecurity Capability Maturity Model (ONG C2M2), and an annual AGA/EEI Security Conference.

Enhancing Pipeline Safety

Pipeline Safety Management Systems

- Promote the use of API RP 1173, Pipeline Safety Management System (PSMS) Recommended Practice, including piloting of the PSMS, teleconferences and workshops to share lessons learned, and tools that can help the industry implement the PSMS.
- Promote the AGA Safety Culture Statement and a positive safety culture throughout the natural gas industry.

Safety Knowledge Sharing

- Continue AGA Board Safety Committee initiatives, such as sharing lessons learned through the Safety Information Resource Center, safety alerts through the AGA Safety Alert System, safety communications with customers, supporting AGA's Safety Culture Statement, and holding an annual Executive Leadership Safety Summit.
- Recognize statistical top safety performers, promote safety performance and encourage knowledge sharing through AGA Safety Awards.
- Continue the work of the AGA Best Practices Programs to identify superior performing companies and innovative work practices that can be shared with others to improve operations and safety.
- Conduct workshops, teleconferences, discussion groups, and other events to share information including pipeline safety reauthorization, DIMP/TIMP, fitness for service, records, in-line inspection, emergency response, and other key safety initiatives

Workforce Development

- Support of the efforts of the Center for Energy Workforce Development, Energetic Women, natural gas boot camps, regional gas associations, and educational institutes on solutions to address the need for a qualified, diverse workforce.

Public Awareness and Emergency Response

- Explore ways to educate, engage and provide appropriate information to stakeholders to increase pipeline public awareness and the need to call if you smell gas.
- Support public awareness programs targeted at damage prevention and pipeline safety awareness
- Use industry training facilities and evaluate opportunities to expand outreach/education programs to external stakeholders.
- Reach out to emergency responder community in order to enhance emergency response capabilities.
- Collaborate with stakeholders near existing transmission lines to increase awareness/adoption of appropriate PIPA recommended best practices.
- Conduct organizational response drills to improve emergency preparedness.
- Participate in state, regional and national multi-agency emergency response training exercises.
- Support industry participation in a mutual assistance program.
- Search for new and innovative ways to inform, engage and provide appropriate information to stakeholders, including emergency responders, public officials, excavators, consumers, safety advocates, and the public living near pipelines.
- Educate the Pipeline Safety Trust and other public stakeholders on distribution and intrastate transmission pipelines, AGA and industry initiatives to improve pipeline safety, and receive input.
- Develop publications dedicated to improving safety and operations.

Pipeline Planning Engagement

- Build an active coalition of AGA member representatives to work with PHMSA and other stakeholders to implement PIPA recommended practices pertaining to encroachment around existing transmission pipelines.

Advancing Technology Development

- Support R&D investment, pilot testing and technology implementation.
- Work with PHMSA and other stakeholders on opportunities to increase R&D funding and deployment of technologies.
- Advocate to state commissions the inclusion of research funding in rate cases.

AGA American Gas Association

AGA's Commitment to Enhancing Safety: Actions Completed

Building Pipelines for Safety

Construction

- ✓ Review and revise established construction procedures to provide for appropriate (risk-based) oversight of contractor installed pipeline facilities.
- ✓ Extend Operator Qualification to include tasks related to new main & service construction.
- ✓ Implement applicable portions of AGA's technical guidance document, "Oversight of new construction tasks to ensure quality."

Emergency Shutoff Valves

- ✓ Expand EFV installation beyond single family residential homes to small commercial and multi-family residential services.
- ✓ Begin risk-based evaluation on the use of automatic shutoff valves, remotely controlled valves or equivalent technology in HCAs.

Operating Pipelines Safely

Integrity Management

- ✓ Confirm the established Maximum Allowable Operating Pressure (MAOP) of transmission pipelines.
- ✓ Under DIMP, evaluate risk associated with trenchless pipeline techniques and implement initiatives to mitigate risks.
- ✓ Under DIMP, identify distribution assets where increased leak surveys may be appropriate.
- ✓ With PHMSA, create a Data Quality & Analysis Team to analyze data PHMSA collects, determine what the data is telling us, issue reports, identify missing information and how best to collect that data, and key metrics that indicate safety concerns.
- ✓ Implement appropriate meter set protection practices identified through AGA Gas Utility Best Practices Program.

Excavation Damage Prevention

- ✓ Implement applicable portions of AGA's technical guidance, "Ways to improve engagement between operators & excavators."

Physical and Cybersecurity/System Controls

- ✓ Create a DNG ISAC.
- ✓ Create a Cybersecurity Task Force to develop products and programs that strengthen cybersecurity.
- ✓ Conduct an all hazard threat analysis and physical security benchmarking survey.
- ✓ Work with TSA to develop and implement Pipeline Security Guidelines.
- ✓ Create a Cybersecurity Assessment Program, including workshops that will allow industry to address their cybersecurity risks.
- ✓ Hold workshops and events: Workplace Violence Prevention & Insider Threats, SCADA, Control Room Management.

Enhancing Pipeline Safety

Safety Knowledge Sharing

- ✓ Create a voluntary AGA Peer Review Program that allows subject matter experts from gas utilities to review peer companies, identify areas that are working well and areas for potential improvement.
- ✓ Work with INGAA, API, AOPL, Canadian Gas Association and Canadian Energy Pipeline Association on a comprehensive safety management study that explores initiatives currently utilized by other sectors and the pipeline industry.
- ✓ Create a Safety Information Resources Center for the sharing of safety information.
- ✓ Hold regional operations executives' roundtables annually to discuss safety initiatives.
- ✓ Annually host roundtables focused on operator experience and lessons learned during the AGA Operations Conference.
- ✓ Develop guidance: To determine a distribution or transmission pipeline's fitness for service and MAOP, and the critical records needed for that determination; For oversight of new construction tasks to ensure quality; For trenchless pipeline installations; That presents benefits and disadvantages of the installation of ASV/RCV block valves on new, fully replaced and existing transmission pipelines; On intergenerational transfer of knowledge for Field Supervisors; Emergency response; Natural gas infrastructure physical security.

Workforce Development

- ✓ Annual AGA Executive Leadership Development Program.
- ✓ Annual Center for Energy Workforce Development (CEWD) Summits.
- ✓ Create an AGA Diversity & Inclusion Task Force.
- ✓ Participate in government/industry initiatives to foster workforce development, such as the Utility Workforce Advisory Council composed of the Departments of Energy, Defense, Labor, Veterans Affairs; AGA, Edison Electric Institute, Nuclear Energy Institute, National Rural Electric Cooperative Association, American Public Power Association, International Brotherhood of Electrical Workers, Utility Workers Union of America, and CEWD.

Public Awareness and Emergency Response

- ✓ Incorporate an Incident Command System (ICS) type of structure into emergency response protocols.
- ✓ Integrate applicable provisions of AGA's emergency response white paper and checklist into emergency response procedures.
- ✓ Create a Safety Alert Notification System that will allow AGA or its members to quickly notify other AGA members of safety issues that require immediate attention.
- ✓ Develop an Emergency Planning Resource Center and a Mutual Assistance Database.
- ✓ Implement AGA discussion groups to address safety issues including technical training and knowledge transfer, material supply chain issues, DIMP implementation, TIMP risk models, Pipeline Safety Management Systems, pipeline safety/compliance/oversight, GPS/GIS and work management systems, contractor/quality management, management of company standards, odorization, compressor operations, public awareness, and damage prevention.

Pipeline Planning Engagement

- ✓ Develop a task group comprised of AGA staff and members to work closely with Pipelines and Informed Planning Alliance (PIPA) to ensure AGA member concerns are addressed in joint PIPA initiatives.

Advancing Technology Development

- ✓ Work with INGAA, research consortiums and other pipeline trade associations to provide the NTSB with a compilation of the progress that has been made in advancing in-line inspection technology.

U.S. Department of Transportation Call to Action
To Improve the Safety of the Nation's Energy Pipeline System

Executive Summary

Today, more than 2.5 million miles of pipelines are responsible for delivering oil and gas to communities and businesses across the United States. That's enough pipeline to circle the earth approximately 100 times.

Currently, these liquid and gas pipelines are operated by approximately 3,000 companies and fall under the safety regulations of the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). PHMSA has engineers and inspectors around the country who oversee the safety of these lines and ensure that companies comply with critical safety rules that protect people and the environment from potential dangers. While PHMSA directly regulates most of the hazardous liquid pipelines in the nation, states take over when it comes to intrastate natural gas pipelines. Every state, except Hawaii and Alaska, is responsible for the inspection and enforcement of state pipeline safety laws for the natural gas pipeline systems within their respective states. Some states – about 20 percent - also regulate the hazardous liquid lines within state borders.

In the wake of several recent serious pipeline incidents, U.S. DOT/PHMSA is taking a hard look at the safety of the nation's pipeline system. Over the last three years, annual fatalities have risen from nine in 2008, to 13 in 2009 to 22 in 2010. Like other aspects of America's transportation infrastructure, the pipeline system is aging and needs a comprehensive evaluation of its fitness for service. Investments that are made now will ensure the safety of the American people and the integrity of the pipeline infrastructure for future generations.

For these reasons, Secretary LaHood has issued "A Call To Action" for all pipeline stakeholders, including the pipeline industry, the utility regulators, and our state and federal partners. Secretary LaHood brought together PHMSA Administrator Quarterman and the senior DOT leadership to design a strategy to achieve that goal. The action plan below is the result of those deliberations.

Background

Much of the nation's pipeline infrastructure was installed many decades ago, and some century-old infrastructure continues to transport energy supplies to residential and commercial customers, particularly in the urban areas across our nation. Older pipeline facilities that are constructed of obsolete materials (e.g., cast iron, copper, bare steel, and certain kinds of welded pipe) may have degraded over time, and some have been exposed to additional threats, such as excavation damage.

On December 4, 2009, PHMSA issued the Distribution Integrity Management Final Rule, which extends the pipeline integrity management principles that were established for hazardous liquid and natural gas transmission pipelines, to the local natural gas distribution pipeline systems. This regulation, which becomes effective in August of 2011, requires operators of local gas distribution pipelines to evaluate the risks on their pipeline systems to determine their fitness for service and take action to address those risks. For older gas distribution systems, the appropriate mitigation measures could involve major pipe rehabilitation, repair, and replacement programs. At a minimum, these measures are needed to requalify those systems as being fit for service. While these measures may be costly, they are necessary to address the threat to human life, property, and the environment.

In addition to the many pipelines constructed with obsolete materials, there are also early vintage steel pipelines in high consequence areas that may pose risks because of inferior materials, poor construction practices, and lack of maintenance or inadequate risk assessments performed by operators. The lack of basic information or incomplete records about these systems is also a contributing factor. The U.S. DOT is seeking to make sure these risks are identified, the pipelines are assessed accurately, and preventative steps are taken where they are needed.

Action Plan

The U.S. DOT and PHMSA have developed this action plan to accelerate rehabilitation, repair, and replacement programs for high-risk pipeline infrastructure and to requalify that infrastructure as fit for service. The Department will engage pipeline safety stakeholders in the process to systematically address parts of the pipeline infrastructure that need attention, and ensure that Americans remain confident in the safety of their families, their homes, and their communities. The strategy involves:

- **A CALL TO ACTION** – Secretary LaHood is issuing a "Call to Action" to engage state partners, technical experts, and pipeline operators in identifying pipeline risks and repairing, rehabilitating, and replacing the highest risk infrastructure. Secretary LaHood is also asking Congress to expand PHMSA's ability to oversee pipeline safety.

    - Secretary LaHood and PHMSA Administrator Quarterman have met with the Federal Energy Regulatory Commission (FERC), the National Association of Regulatory and Utility Commissioners (NARUC), state public utility commissions, and industry leaders to ask all parties to step up efforts to identify high-risk pipelines and ensure that they are repaired or replaced.

    - Secretary LaHood is asking Congress to increase the maximum civil penalties for pipeline violations from $100,000 per day to $250,000 per day, and from $1 million for a series of violations to $2.5 million for a series of violations. He is also asking Congress to help close regulatory loopholes, strengthen risk management requirements, add more inspectors, and improve data reporting to help identify potential pipeline safety risks early. The Senate has passed its version of the pipeline safety reauthorization legislation. The House of Representatives is currently considering two versions of a similar bill that could be passed by end of the year.

    - The U.S. DOT and PHMSA convened a Pipeline Safety Forum in April 2011 that engaged a working session around the actions that DOT/PHMSA, the state regulatory agencies, and the pipeline industry can take to drive more aggressive actions to raise the bar on pipeline safety. The U.S. DOT and PHMSA is preparing a report based on ideas, opportunities and challenges presented at the Forum and action that will be taken.

- **AGGRESSIVE EFFORTS** – The U.S. DOT and PHMSA are calling on pipeline operators and owners to review their pipelines and quickly repair and replace sections in poor condition.
    - PHMSA has asked technical associations and pipeline safety groups to provide best practices and technologies for repair, rehabilitation and replacement programs, and has asked industry groups for commitments to accelerate needed repairs.
    - PHMSA will review all data received from pipeline operators to identify areas with critical needs.
    - PHMSA's Distribution Integrity Management rule became effective in August, requiring all operators of local gas distribution pipeline systems to evaluate the risks on their pipeline systems and take action to address those risks.
- **TRANSPARENCY** - U.S. DOT and PHMSA will execute this plan in a transparent manner with opportunity for public engagement, including a dedicated website for this initiative, and regular reporting to the public.
    - PHMSA has launched a public website (http://opsweb.phmsa.dot.gov/pipelineforum), which describes the ongoing pipeline rehabilitation, replacement and repair initiatives.
    - All materials from the Pipeline Safety Forum will be publicly posted to the web, followed by a Draft Report for Notice and Comment. Once public input has been collected, PHMSA will publish a final Pipeline Safety Report to the Nation.
    - PHMSA will be holding a national forum on emergency preparedness and response to pipeline emergencies. The forum will take place December 9, 2011, and will include the major stakeholders from the emergency response community, industry and government to discuss how best to improve pipeline emergency preparedness and response capabilities.
    - A report from the forum will be prepared and published.

Revised 11/1/11

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THE SECRETARY OF TRANSPORTATION
WASHINGTON, D.C. 20590

March 28, 2011

Recent pipeline failures around the country have elevated concerns about pipeline safety. Neighborhoods in Allentown, Pennsylvania, and San Bruno, California, were rocked by fatal explosions caused by natural gas pipeline failures. These tragic events took lives, shook communities, and raised serious questions about the safety of some of our aging pipeline infrastructure.

These and other recent pipeline incidents, such as the one last summer in Marshall, Michigan, causing a large oil spill into sensitive waters, underscore the need to develop a comprehensive solution that will prevent accidents like these from recurring. The U.S. Department of Transportation (DOT) will host a Pipeline Safety Forum on these issues on April 18 in Washington, DC, and I invite you or your representative(s) to participate. This forum will bring together key stakeholders, including pipeline companies, State and Federal agencies, technical experts, public safety advocates, and the public, to tackle these issues head-on and discuss workable solutions. You or your representative(s) may RSVP for the Pipeline Safety Forum at pipelineforum@dot.gov.

We appreciate your State's partnership on pipeline safety inspection and enforcement. In 2009, the Pipeline and Hazardous Materials Safety Administration provided the majority of the funding for your pipeline safety program, trained your State's inspectors alongside our own, and worked with them to enforce your State pipeline safety laws.

Now, we want to partner with you again to ensure that all pipeline companies in your State, both public and private, are correctly analyzing the risks to their pipeline systems and using the appropriate assessment technologies. Your pipeline safety staff can help make this happen. We ask you to urge your staff to encourage companies and the State utility commission to accelerate pipeline repair, rehabilitation, and replacement programs for systems whose integrity cannot be positively confirmed. This is one of the best ways to help protect your citizens from accidents like those in Allentown, Marshall, and San Bruno.

In addition, there are several other actions you could take to prevent other types of pipeline accidents in your State. These include the following:

Issue a Proclamation on Safe Digging Month. You can help raise awareness about the importance of calling before you dig by issuing a State proclamation and holding a public awareness event. As you may know, April is National Safe Digging Month, and DOT will be highlighting our *811 Safe Digging Initiative.* Since establishing the 811 number in 2007 and raising awareness among excavators and do-it-yourselfers alike of the importance of calling 811 before digging, the number of gas distribution leaks caused by excavation damage has dropped by more than 45 percent. Even with this progress, excavation damage remains the number one cause of pipeline failures causing serious injuries and deaths. Your State proclamation will help raise awareness about this critical safety issue.

Enforce One-Call Laws. One of the critical components of a strong damage prevention program is fair and effective enforcement of the one-call laws. Governors play a vital role in supporting improved pipeline safety and a sound infrastructure, and we encourage your support for improvements in one-call laws and programs. Effective damage prevention laws are characterized by few or no exemptions from participation in the safe digging process, balanced enforcement that holds all parties accountable, and clearly defined responsibilities.

Encourage Better Land Use and Development. Another important damage prevention initiative is aimed at helping your cities and towns make better decisions about land use and development around existing pipelines. We have published a report on suggested practices and model legislation to help town planners and local officials coordinate with pipeline companies to ensure the safety of people and the environment. This report, called the Pipeline Informed Planning Alliance Report, can be found on our Web site at http://www.phmsa.dot.gov. Please help us by referring land use planners in your State to this report so they can make informed decisions about the best use of land near pipelines transporting natural gas or hazardous liquids.

I look forward to working with you on this critical safety issue. If the Office of the Secretary or DOT's Pipeline and Hazardous Material Safety Administration can be of any assistance to you, please contact Administrator Cynthia L. Quarterman at 202-366-4831.

Sincerely yours,

Ray LaHood

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

APPLICATION OF ATMOS ENERGY	**)**	
	)	
CORPORATION FOR AN ADJUSTMENT	**)**	**Case No. 2018-00281**
	)	
OF RATES AND TARIFF MODIFICATIONS	**)**	

REBUTTAL TESTIMONY OF GREGORY W. SMITH

I. POSITION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Gregory W. Smith, P.E. My business address is 810 Crescent Centre Drive # 600, Franklin, Tennessee, 37067.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Vice President of Technical Services for Atmos Energy Corporation's Kentucky/Mid-States Division (hereinafter "Atmos Energy" or the "Company").

Q. ARE YOU THE SAME GREGORY SMITH THAT FILED PREFILED TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. ARE YOU SPONSORING ANY EXHIBITS AS PART OF YOUR REBUTTAL TESTIMONY?

A. Yes. I am sponsoring Exhibit GWS-R-1 PHMSA Advisory Bulletin (FR Doc. 07-4309).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to rebut statements made by the Attorney General's Witness, Mr. Lane Kollen, about planned capital projects and explain why the current and forecasted capital expenditures of the Company are critical from a safety and reliability perspective.

Q. DO YOU AGREE WITH MR. KOLLEN'S CHARACTERIZATION OF THE COMPANY'S CAPITAL EXPENDITURES?

A. No. Mr. Kollen states "that Atmos has every intention of to significantly increase its combined PRP and non-PRP investment each year and to seek annual base rate increases…" Mr. Martin addresses the PRP and Non-PRP terminology in his direct and rebuttal testimony. I disagree with Mr. Kollen in that he focuses his argument from a revenues perspective, and appears to ignore the safety and reliability results being achieved by the Company. His testimony only seems to justify capital investment based on "growth" and "use" while ignoring the risk of an aging system and the materials therein. The purpose of my testimony is to describe how the safety and reliability results of the Company's ongoing capital expenditures have been beneficial to Atmos Energy customers and the communities we serve and how proactive investment is necessary in order to reach our goal of being the safest provider of natural gas

Q. WHY IS ENSURING SAFETY AND RELIABILITY ATMOS ENERGY'S HIGHEST GOAL?

A. Atmos Energy's acute focus on safety and reliability stems from an awareness of the implications of the Company's actions for the safety of our customers, communities, and employees; it is our highest priority. Our commitment to safety and reliability is threaded throughout our corporate culture.

We have worked and continue to work with regulators, industry associations, and other stake holders to take proactive measures to better know our system, improve our geographic information system ("GIS") records, and eliminate risks and threats. Atmos Energy is required as a prudent operator, and within our Distribution Integrity Management Plan, to continually seek and assess opportunities to improve upon the safety of our operations and the public.

Q. PLEASE DESCRIBE THE VARIOUS PIPE MATERIALS THAT ARE UTILIZED IN ATMOS ENERGY'S KENTUCKY GAS DISTRIBUTION SYSTEM.

A. The U.S. Department of Transportation ("DOT") uses the following categories to classify main and service line materials: steel, ductile iron, copper/wrought iron, plastic PVC, plastic polyethylene ("PE"), plastic ABS[1], plastic other and other. Steel pipe has been used in the natural gas industry since the 1800s and the use of plastic pipes began in the 1960s. As improved materials are developed, older materials are discontinued or phased out by the industry. As a result, the Company has many miles of pipe in our distribution system in Kentucky that are made of materials that are no longer used by Atmos Energy in new natural gas pipeline construction.

[1] Acrylonitrile butadiene styrene.

Steel pipe is categorized as bare steel or coated steel. In addition, each of those categories can be further broken down as cathodically protected or unprotected. The gas industry installed bare steel pipe until the mid-1950s. As technology advanced, the gas industry began to use cathodically protected steel pipe, and since 1970, cathodically protected coated steel pipe is the only steel material approved for the new installations by the DOT.[2] All of the bare steel pipe in Atmos Energy's Kentucky system was installed before Atmos Energy acquired those systems from Western Kentucky Gas in 1987 and bare steel pipe is the oldest pipe in Atmos Energy's Kentucky system. Currently there are approximately 144 miles of bare steel mains in Atmos Energy's Kentucky system, approximately 33 miles of which is not under cathodic protection. Atmos Energy has eliminated all known quantities of Cast Iron from our pipeline system in Kentucky.

Similar to steel pipe, plastic pipe has undergone significant refinement over the past several decades. In Atmos Energy's Kentucky system, the early generation plastic categories consisted of PVC, Aldyl-A, and medium density polyethylene ("MDPE"). Atmos Energy has eliminated all known quantities of PVC from our pipeline system in Kentucky.

Aldyl-A is an early generation PE pipes installed by the natural gas industry from the 1960s through the early 1980s. Technological advancements led the industry to discontinue the use of Aldyl-A and adopt medium density polyethylene

[2] 49 C.F.R. § 192.461

(PE2406). Atmos Energy currently uses High Density polyethylene (PE3408)("HDPE") for all growth and replacement projects.

Atmos Energy's Kentucky distribution pipeline miles and service line inventories by material are shown on Tables GWS-R-1 and GWS-R-2 below. In addition to the amounts below, Atmos Energy Kentucky also has approximately 184 miles of coated steel transmission pipeline.

Table GWS-R-1 – Atmos Energy Kentucky Distribution Pipeline Inventory by Material

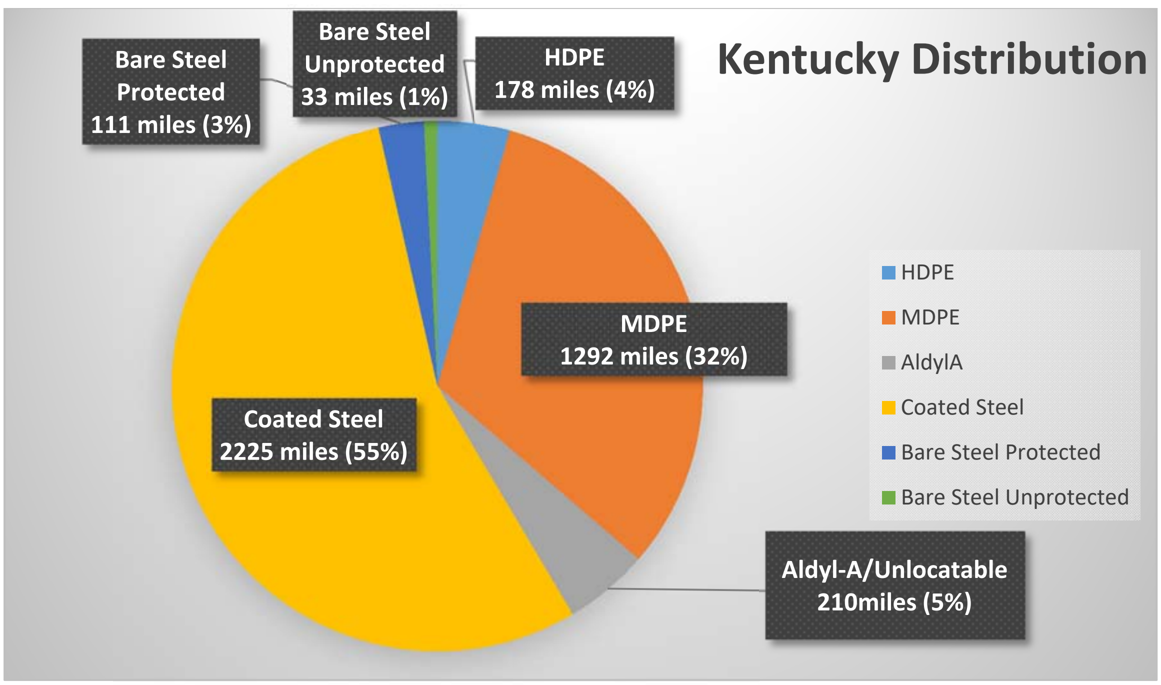
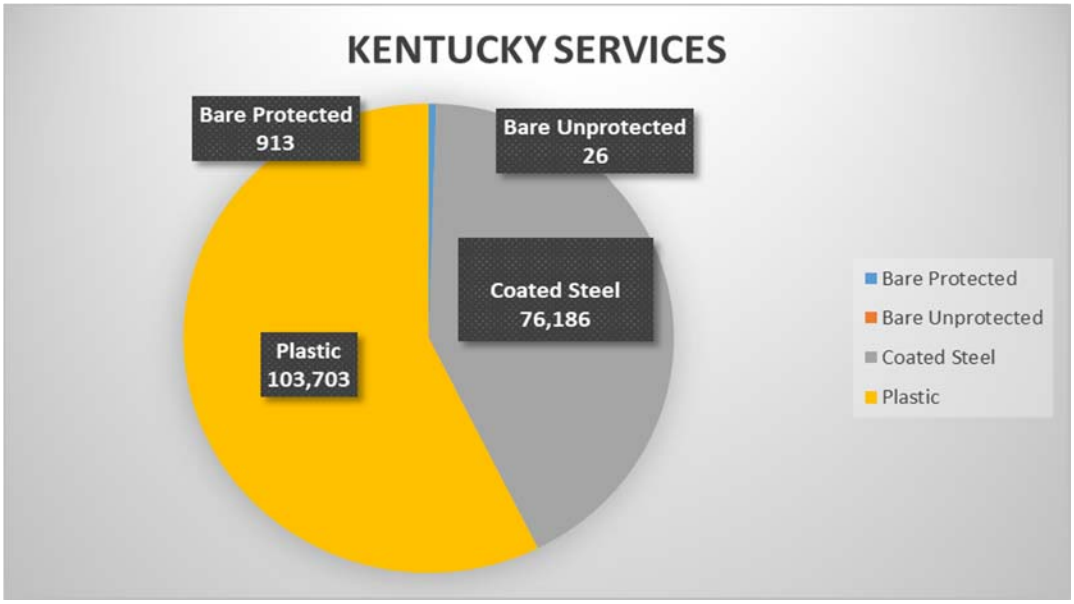


Table GWS-R-2 – Atmos Energy Kentucky Service Line Inventory by Material



Q. HAVE THE COMPANY'S CAPITAL EXPENDITURES ENHANCED THE SAFETY AND RELIABILITY OF THE ATMOS ENERGY PIPELINE SYSTEM IN KENTUCKY?

A. Yes. As mentioned in my direct testimony, the Company has continued to replace aged pipelines and materials that have outlived their useful life or pose a risk to reliability or safety since I testified previously in Case No. 2017-00349. Results of the Company's capital investment, in particular the replacement of bare steel, has resulted in a reduction of leaks as well as Lost and Unaccountable (L&U) gas on the Atmos Energy Kentucky system as the Company responded to AG DR No. 1-12. I have updated the leak history chart below from my direct testimony to also include January 2019 leak amounts in Table GWS-R-3 and Table GWS-R-4. The January 2019 amount reinforces the continued trend that the Company's targeted projects are having a noticeable effect in reducing leaks and enhancing safety. Tables GWS-R-5 and GWS-R-6 highlight the reduction in L&U gas in recent years.

TABLE GWS-R-3

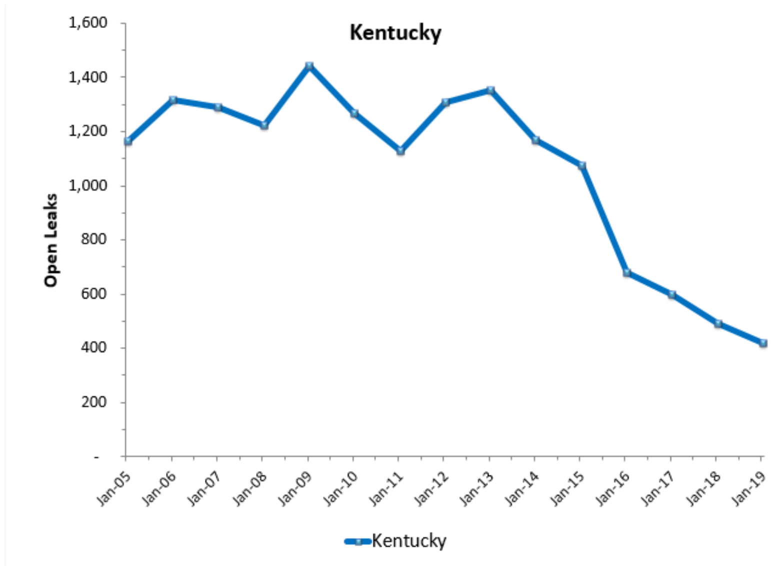


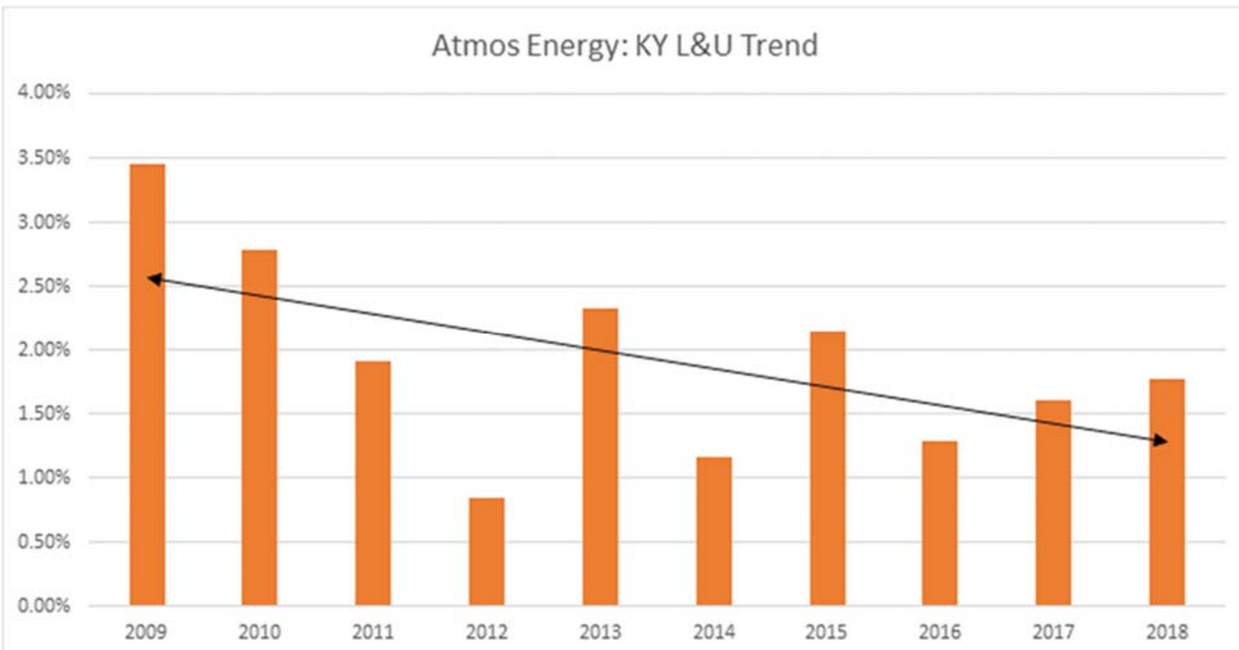
TABLE GWS-R-4

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
Jan, 2018	489
Jan, 2019	420

TABLE GWS-R-5

Year	Gas IN	Gas Out	L&U Volume	L&U %
2009	44,910,320	43,360,933	1,549,387	**3.45%**
2010	45,531,153	44,258,607	1,272,546	**2.79%**
2011	47,173,417	46,273,371	900,046	**1.91%**
2012	48,812,427	48,404,699	407,728	**0.84%**
2013	54,894,308	53,622,826	1,271,482	**2.32%**
2014	59,047,532	58,363,294	684,238	**1.16%**
2015	63,213,274	61,852,894	1,360,380	**2.15%**
2016	56,015,188	55,295,758	719,430	**1.28%**
2017	54,776,498	53,895,646	880,853	**1.61%**
2018	60,470,689	59,419,538	1,070,243	**1.77%**

TABLE GWS-R-6



Q. WHAT ARE THE MAIN CAUSES OF LEAKS ON BARE STEEL PIPE?

A. The most frequent cause of leaks on bare steel pipe is corrosion. Atmos Energy reports root causes for leak repairs annually on our DOT reports (a copy is also sent to each of our State Pipeline Safety Departments). Over the last three years, excluding excavation damage, approximately 40% of all leaks repaired on Atmos Energy's Kentucky system were caused by corrosion.

Q. IS ATMOS ENERGY'S PIPELINE SYSTEM IN KENTUCKY IN JEOPARDY?

A. No. As also mentioned in the rebuttal testimony of Company witness John McDill, Atmos Energy's natural gas pipeline system in Kentucky is not in imminent danger of catastrophic failure. However, as pipe ages, the likelihood of pipeline failure increases, also increasing the likelihood of an occurrence of pipeline failure. For this reason, delaying pipe replacement until there is an imminent threat to public safety is not a good policy. The continuance of the Company's accelerated replacement plan will facilitate the complete retirement or replacement of the specific pipe materials posing an increased risk to safety and reliability because they are prone to failure over time from the threat of corrosion (for bare steel), brittle cracking (Aldyl-A, and legacy plastic as advised by PHMSA Advisory Bulletin (FR Doc. 07-4309) and included as Exhibit GWS-R-1) and third party damage (unlocatable plastic). Atmos Energy believes these materials should be targeted, on an accelerated basis within our overall replacement cycle, to ensure the Company's gas distribution system remains safe and reliable. When complete, Atmos Energy will begin looking at other early generation plastic as our systems continue to age as advised by the PHMSA Advisory Bulletin (FR Doc. 07-4309). Finally, as explained in more detail below, there are conditions in our system other than material types of gas pipe that create increased risks to safety that warrant accelerated replacement, such as the elimination of High Consequence Areas (HCAs).

Q. IS THE ATMOS ENERGY PIPELINE SYSTEM IN KENTUCKY SAFE?

A. Yes. Atmos Energy is very proud that, overall, our system has proven to be safe and reliable. While no one can guarantee there will never be an incident, we can and do monitor and inspect our system, identify risks, and remediate issues where they arise. However, past success is not a guarantee of future safety and I believe that the proactive steps we have made with regards to accelerated replacement of higher risk infrastructure is to be credited in these results. Our rate of replacement must exceed the rate of material aging and risk of failure.

Q. IS ATMOS ENERGY COMMITTED TO REPLACING THE BARE STEEL IN THE TIMELINES LAID OUT BY THE COMMISSION IN ITS FINAL ORDER IN CASE NO. 2017-00349.

A. Yes. The Company had proposed to accelerate the replacement of bare steel in a manner that would have resulted in the replacement of all bare steel by 2022 as proposed in Case No. 2017-00349. However, in light of the Commission's final order in that proceeding, the Company is now following the judgment of the Commission to slow down replacement of bare steel at an annual rate targeting completion of bare steel replacement by 2027 at a targeted capital expenditure of approximately $28 million per year on bare steel replacement projects.

Q. WILL THE COMPANY CONTINUE TO PROVIDE A PROJECT REPORT TO THE COMMISSION REGARDING ITS BARE STEEL PROJECTS SIMILAR TO WHAT IT PROVIDED IN ITS PRP FILINGS?

A. Yes. As mentioned in my direct testimony, replacing bare steel mains and services is a high priority and the Company will still be replacing bare steel at the accelerated rate in accordance within the timeframe set forth in the Commission's order in Case No. 2017-00349. The Company would file its annual plan for bare steel replacement on or before August 1st. The filing would reflect the names, descriptions, and estimated costs for bare steel replacement projects in the upcoming fiscal year which commences on October 1st. The intent of this filing is to address any concerns held by the Commission and/or Attorney General's office on expected bare steel replacement spend as a result of Case No. 2017-00349.

Q. WOULD THE COMPANY ALSO FILE WITH THE COMMISSION AN ANNUAL PROJECT REPORT FOR ITS NON-BARE STEEL PROJECTS?

A. As detailed in the direct testimony of Mark Martin and Gregory Waller, the Company now seeks recovery of all investment through the traditional ratemaking process in annual traditional forward looking rate case filings as described in the Company's response to Staff DR No. 2-05. The nature of this traditional ratemaking process provides the opportunity to review the details of all capital investment via the Minimum Filing Requirements (MFRs) and/or discovery requests. The annual traditional rate case filings under KRS 278.192 are necessary as any prudent pipeline operator such as Atmos Energy must consider the overall replacement cycle of its system.

Q. WOULD MR KOLLEN'S SUGGESTION TO "LIMIT NON-PRP CAPITAL EXPENDITURES INCLUDED IN THE TEST YEAR TO A REASONABLE AMOUNT BASED ON THE COMPANY'S MOST RECENT THREE-YEAR ACTUAL NON-PRP EXPENDITURES" IMPACT THE SAFETY AND RELIABILITY OF THE ATMOS ENERGY PIPELINE SYSTEM IN KENTUCKY?

A. Yes. As noted in my direct testimony, there are other types of pipeline materials that I, as well as other state and federal regulatory agencies, have advised warrant accelerated replacement. For example, Atmos Energy has also planned replacement of all remaining low pressure systems in Kentucky (approximately 45 miles) with intermediate pressure systems including regulators with relief valves at each customer meter and renewed service lines containing excess flow and curb valves. Low pressure systems operate at less than 1 psig and may allow water to enter the system when leaks develop. Water entering the system can lead to service outages and increase the risk of internal corrosion. Also, sixty percent (60%) of the materials within our low pressure systems are currently categorized under our bare steel replacement plan. Therefore, it makes sense to target these systems for replacement and overall public risk reduction.

Atmos Energy will also target above ground infrastructure such as referenced by including farm taps and legacy regulator stations. Modern station design includes warnings and alarms with regards to faults in odorization equipment, remote monitoring of pressures and gas flows, and remote operated shut-off valves in case of emergency.

Utilities need to have appropriate replacement cycles for <u>all</u> of their pipeline infrastructure. Atmos Energy has approximately 4,200 miles of natural gas distribution and transmission pipeline (plus associated service lines) in Kentucky. If we were to replace 42 miles of pipe per year (1% per year), it would take 100 years to renew the entire system…and future generations would be left with a pipeline system with 100-years-old segments. A prudent pipeline operator must consider the overall replacement cycle of its system to ensure future customer safety. Mr. Kollen does not take this analysis into consideration in his proposal to limit capital expenditures.

Q. PLEASE DESCRIBE THE NEED FOR REPLACEMENT FOR OTHER INFRASTRUCTURE IN ADDITION TO THE COMPANY'S BARE STEEL PIPELINE?

A. The Company is committed to maintaining and enhancing the level of safety provided to its customers. The fulfillment of that commitment requires ongoing and systematic replacement of aging facilities at a rate higher than has been achieved in recent history. Increasing the rate of replacement, has, required an accelerated level of capital investment. This trend is not unique to Atmos Energy but rather universal to virtually all natural gas distribution providers. In every case, there is more prudent replacement work needed than capital available in any given year. My role is to recommend target materials and system types for available budgeted capital.

Q. PLEASE PROVIDE ADDITIONAL DETAIL ABOUT ATMOS ENERGY'S ALDYL-A AND UNLOCATABLE PLASTIC REPLACEMENT EFFORTS.

A. By continuing its focus on replacement, the Company will replace all services, yard lines and mains that are constructed of Aldyl-A or located within plastic systems that are deemed unlocatable by local operations. Based on current records, we have approximately 210 miles of system that fall under these two categories. Record review is ongoing and will continue for the next few years as we continue the DIM directive to better our system knowledge and prioritize system risk. Atmos Energy believes a majority of the unlocatable plastic on its system consists of Aldyl-A pipe. After bare steel pipe, the Company considers Aldyl-A the most significant material risk on its system.

Q. WHAT ARE THE MAIN CAUSES OF LEAKS ON ALDYL-A?

A. As these materials age, the structure of the pipe weakens, becomes brittle and eventually cracks. In 2007, PHMSA issued an Advisory Bulletin ADB-07-01 for updated notification of the susceptibility of older plastic pipes to premature brittle-like cracking. The older pipes listed included Aldyl-A. The advisory bulletin noted that:

> Brittle-like cracking refers to crack initiation in the pipe wall not immediately resulting a full break followed by stable crack growth at stress levels much lower than the stress required for yielding. This results in very tight, slit-like, openings and gas leaks. Although significant cracking may occur at point of stress concentration and near improperly designed or installed fittings, small brittle-like cracks may be difficult to detect until a significant amount of gas leaks out of the pipe, and potentially migrates into an enclosed space such as a basement.

A copy of the Advisory Bulletin is included as Exhibit GWS-R-1 to my rebuttal testimony. The brittle-like cracking characteristic could cause a leak on an early vintage plastic pipeline such as Aldyl-A to grow and release additional natural gas than would normally be released, increasing the risk of natural gas gathering and igniting. The Commission recently commented on the risks of Aldyl-A in Case No. 2018-00086 as discussed by Company witness John McDill.

Q. IS REPLACEMENT OF ALDYL-A PIPE THE ONLY POSSIBLE REMEDY?

A. Yes, replacement is the only remedy for these pipes. As stated above Aldyl-A is not used for new installations due to safety concerns. There is no remedial action that will reverse the brittleness or cracking of this early generation plastic pipe.

Q. WHAT TYPES OF MATERIALS WILL ATMOS ENERGY USE TO REPLACE THESE PIPES?

A. Atmos Energy will replace these obsolete materials with current generation PE pipe.

Q. WHY IS ATMOS ENERGY REPLACING UNLOCATABLE PLASTIC?

A. Unlocatable plastic is earlier generation plastic pipe installed without tracer wire or ability for the Company or third parties to confidently locate this pipe. The inability to pinpoint underground piping within the state tolerance range of 18” places excavators and the public at risk for line breaks and gas migration. This early generation pipe, which includes Aldyl-A, poses a significant third-party damage risk, and due to its older age as well as its inability to be effectively located should be replaced over time.

Q. PLEASE DESCRIBE SOME OF THE SIGNIFICANT PROJECTS DRIVING THE COMPANY'S INCREASING NON-BARE STEEL CAPITAL INVESTMENT.

A. The list of the Company's non-bare steel investment was provided as Attachment 1 to the Company's response to Staff DR No. 3-22. A few of the primary drivers include:

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

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

3) KY Farm Tap projects - per PHMSA amended 192.740 regulation (published 3/24/17) titled 'Pressure regulating, limiting, and overpressure protection - Individual service lines directly connected to a production,

gathering, or transmission pipeline' (AKA 'Farm Tap Rule'), operators have 3 years to rebuild or modify 'Farm Tap' stations to be routinely inspected every 3 years using the same criteria as distribution system stations. Atmos Energy has approximately 928 farm taps to rebuild/replace and has budgeted work in several cost centers in order to meet this regulatory deadline.

Each of these projects serve to greatly enhance the safety and reliability of Atmos Energy's system in Kentucky, as well as emphasize the need for critical safety spending on infrastructure beyond just bare steel projects.

Q. ARE THERE INCREASING SAFETY REGULATIONS AND REGULATORY CHANGES IN PLACE THAT ATMOS ENERGY IS REQUIRED TO FOLLOW AS A PRUDENT PIPELINE OPERATOR?

A. Yes. As I detailed in my response to AG Set No. 2-25, the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") has published approximately 12 Final Rules, Interim Final Rules, or Advisory Bulletins since 2011 alone. A sample of those with the most significant impact to Atmos Energy are listed below in Table GWS-R-7.

TABLE GWS-R-7

Part 192 Regulatory Changes		
Published Date	Subject	Reference
3/11/2015	Pipeline Safety: Miscellaneous Changes to Pipeline Safety Regulations	FR12762
10/14/2016	Pipeline Safety: Expanding the Use of Excess Flow Valves in Gas Distribution Systems to Applications Other Than Single-Family Residences	FR70987
12/19/2016	Pipeline Safety: Safety of Underground Natural Gas Storage Facilities	FR91860
1/23/2017	Pipeline Safety: Operator Qualification, Cost Recovery, Accident and Incident Notification, and Other Pipeline Safety Changes	FR7972

In addition, PHMSA also publishes NTSB Safety Recommendations which operators are expected to evaluate as a best practices and incorporate as prudent operators. Those that have had the most significant impact for Atmos Energy in regards to construction, maintenance, compliance, and recordkeeping include those listed in Table GWS-R-8.

TABLE GWS-R-8

Part 192 Regulatory Changes		
Published Date	Subject	Reference
3/11/2015	Pipeline Safety: Miscellaneous Changes to Pipeline Safety Regulations	FR12762
10/14/2016	Pipeline Safety: Expanding the Use of Excess Flow Valves in Gas Distribution Systems to Applications Other Than Single-Family Residences	FR70987
12/19/2016	Pipeline Safety: Safety of Underground Natural Gas Storage Facilities	FR91860
1/23/2017	Pipeline Safety: Operator Qualification, Cost Recovery, Accident and Incident Notification, and Other Pipeline Safety Changes	FR7972

Q. HAS ATMOS ENERGY MADE OTHER SAFETY CHANGES IN RESPONSE TO THESE GUIDELINES AND IN ORDER TO ENHANCE THE OVERALL SAFETY AND RELIABILITY OF ITS SYSTEM?

A. Yes. Atmos Energy has also made several significant O&M and Construction Procedure changes in accordance with 192 Subpart P - Gas Distribution Pipeline Integrity Management (effective 2010) - to provide continuous evaluation and improvement based on reduction of risk and threats to the gas distribution system. Some of the identified measures that have significant impact to construction, maintenance, compliance, and recordkeeping include:

- Escalation of grade 2 and grade 3 leak repairs to a higher minimum standard than required by 192
- Annual leak survey of all bare steel distribution systems
- Pre/Post CCTV camera of sewer mains and laterals to eliminate opportunity for cross-bore

- Addressing third party excavation training through establishment of a dedicated Damage Prevention Specialist role
- Mobilization and immediate construction response to all 'unlocatable/difficult to locate' excavation requests
- Establishing a formal 'Stand and Watch' program for third party excavating around high risk facilities such as Transmission Pipelines and in the vicinity of Regulator Stations
- QA/QC Programs in place for leak surveying and poly joining/fusion - including destructive testing
- GIS and As-Built Mapping Standards: closing packet documentation, testing of new technology for electronic capture of GPS and material barcoding to ensure material tracking and traceability

These identified safety measures have been instituted by Atmos Energy in response to evolving guidelines as well as Atmos Energy's determination to be the safest provider of natural gas in the industry.

Q. WHY IS THE ACCELERATED REPLACEMENT OF THESE PIPELINES APPROPRIATE?

A. With the accelerated replacement of legacy infrastructure, Atmos Energy seeks to reduce the risk to persons and property associated with the potential failure of these service lines, yard lines and mains consisting of now-obsolete materials. As discussed in the rebuttal testimony of Company witness John McDill, it is both reasonable and prudent for the Company to continue the accelerated replacement of pipe comprised of materials with known and documented risks. It is particularly reasonable given the demonstrated downward trend in leak detection and L&U experienced on Atmos Energy's Kentucky facilities over the last few years as a direct result of the Company's focus on the accelerated replacement of these obsolete materials. Replacement of these pipes allows Atmos Energy to mitigate the risk of incidents that can result in death, injury, or significant property damage. It would be in the public interest to allow Atmos Energy to continue its capital spending to accelerate the replacement of pipes constructed of these types of materials.

Q. ULTIMATELY, WHAT ARE THE BENEFITS TO CUSTOMERS OF THE ACCELERATED REPLACEMENT OF THE BARE STEEL, ALDYL-A AND UNLOCATABLE PIPES?

A. Accelerated replacement of these obsolete materials will improve system safety and reliability. Importantly, the new pipe will have the accurate, verifiable, and complete records required by federal regulation in order to perform more detailed risk assessments of the Kentucky distribution system in the future. Certain technical records for parts of the Kentucky distribution systems are unusable or unavailable today because they were of poor quality or nonexistent during the time that the systems were operated or acquired from the predecessor companies. Part 192 regulations[3] require that data be gathered during new pipe installations and when existing facilities are exposed during routine maintenance in order to enhance our knowledge and analyses of our systems. Therefore, an ancillary benefit of continued accelerated replacement of pipe is establishing accurate pipe and component data during pipe replacement activities and then storing that information

[3] 49 C.F.R. Part 192.

in the GIS and asset management databases to enable better risk assessments in the future.

The continued accelerated replacement will also reduce the inconvenience to the public by taking a proactive approach to project identification and execution rather than a reactive approach. Historically, many projects were identified and executed to eliminate an immediate hazardous threat to public safety and customer reliability after signs of failure began to occur. The continued accelerated replacement of pipe will facilitate Atmos Energy's replacement of legacy pipe prior to the detection of an immediate hazardous threat so each project can be more efficient in both size and scope. The work that is involved in replacing distribution systems with current material and construction standards includes: removal of low pressure distribution systems; establishing 2-way feeds; eliminating above-ground regulator stations and relocation away from near-traffic locations; removing pipe from rear easements; moving gas meters from behind fences and under carports to meet current codes and accessibility requirements; establishing CP Test Points; retiring abandoned service stubs; installing distribution valves for better isolation and emergency control; and installation of excess flow valves and/or curb valves for each service line that is replaced. In addition to the overall decrease in system leaks being scheduled for repair – these physical improvements to our systems, at time of replacement, helps ensure our system reliability as an energy source for customers and the communities we serve.

Q. HAVE THE COMPANY'S CAPITAL PROJECTS INVESTMENTS IN THE PAST AND INCLUDED IN THIS CASE BEEN MADE TO SERVE CUSTOMERS?

A. Yes. These investments were made to provide service to Atmos Energy's Kentucky customers and are therefore used and useful for our customers.

Q. WAS ATMOS ENERGY PRUDENT IN MANAGING THESE PROJECTS TO BE AS COST EFFECTIVE AS POSSIBLE?

A. Yes. Atmos Energy is committed to managing its projects and acting prudently so that the ultimate cost to the consumer is just and reasonable.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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safety procedures used for filling, operating, and discharging MATs to determine whether additional safety procedures should be implemented. To this end, we request that persons who use such transportation systems to provide us with information on the effectiveness of the current DOT regulations, consensus standards, and industry best practices. We are also interested in any other procedures utilized to ensure that operations related to the transportation of acetylene on MATs are performed safely.

We would also like to work with shippers, carriers, and facilities that receive shipments of acetylene in MATs to develop and implement a pilot program to test the effectiveness of current or alternative procedures or methods designed to enhance the safety of transportation operations involving acetylene on MATs. As part of this program, we will assist individual companies or facilities to evaluate the effectiveness of their current procedures and to identify additional measures that should be implemented. We welcome suggestions concerning how such a program should be structured and the entities that should participate.

To ensure that our message reaches all stakeholders affected by these risks, we plan to communicate this advisory through our public affairs notification and outreach processes. For additional visibility, we have made this advisory available on the PHMSA homepage at *http://www.phmsa.dot.gov* and the DOT electronic docket site at *http://dms.dot.gov.* In addition, if you are aware of other companies that are involved in the charging, operating, and discharging MATs, please share this advisory notice with them and, if possible, identify them in your correspondence with this agency. We believe a collaborative effort involving an integrated and cooperative approach will help us to address safety risks, reduce incidents, enhance safety, and protect the public.

Issued in Washington, DC on August 30, 2007.

Theodore L. Willke,

Associate Administrator for Hazardous Materials Safety.

[FR Doc. 07–4355 Filed 9–5–07; 8:45 am]

BILLING CODE 4910–60–P

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

[Docket No. PHMSA–2004–19856]

Pipeline Safety: Updated Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.

ACTION: Notice; Issuance of Advisory Bulletin.

SUMMARY: PHMSA is issuing this updated advisory bulletin to owners and operators of natural gas pipeline distribution systems concerning the susceptibility of older plastic pipe to premature brittle-like cracking. PHMSA previously issued three advisory bulletins on this subject: Two on March 11, 1999 and one on November 26, 2002. This advisory bulletin expands on the information provided in the three prior bulletins by listing two additional pipe materials with poor performance histories relative to brittle-like cracking and by updating pipeline owners and operators on the ongoing voluntary efforts to collect and analyze data on plastic pipe performance. Owners and operators of natural gas pipeline distribution systems are encouraged to review the three previous advisory bulletins in their entirety.

FOR FURTHER INFORMATION CONTACT: Richard Sanders at (405) 954–7214, or by e-mail at *richard.sanders@dot.gov.*

SUPPLEMENTARY INFORMATION:

I. National Transportation Safety Board (NTSB) Investigation

On April 23, 1998, the National Transportation Safety Board (NTSB) issued its Special Investigation Report, *Brittle-Like Cracking in Plastic Pipe for Gas Service,* NTSB/SIR–98/01. The report described the results of the NTSB's special investigation of polyethylene gas service pipe, which addressed three major safety issues: (1) Vulnerability of plastic piping to premature failures due to brittle-like cracking; (2) adequacy of available guidance relating to the installation and protection of plastic piping connections to steel mains; and, (3) effectiveness of performance monitoring of plastic pipeline systems to detect unacceptable performance in piping systems.

(1) *Vulnerability of plastic piping to premature failures due to brittle-like cracking:* The NTSB found that failures in polyethylene pipe in actual service are frequently brittle-like, slit failures, not ductile failures. It concluded the number and similarity of plastic pipe accident and non-accident failures indicate past standards used to rate the long-term strength of plastic pipe may have overrated the strength and resistance to brittle-like cracking for much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s. The NTSB also concluded any potential public safety hazards from these failures are likely to be limited to locations where stress intensification exists. The NTSB went on to state that more durable modern plastic piping materials and better strength testing have made the strength ratings of modern plastic piping more reliable.

(2) *Adequacy of available guidance relating to the installation and protection of plastic piping connections to steel mains:* The NTSB concluded that gas pipeline operators had insufficient notification of the brittle-like failure potential for plastic pipe manufactured and used for gas service from the 1960s to the early 1980s. The NTSB also concluded this may not have allowed companies to implement adequate surveillance and replacement programs for older plastic piping. The NTSB explained the Gas Research Institute (GRI) developed a significant amount of data on older plastic pipe but the data was published in codified terms making it insufficient for use by pipeline system operators. The NTSB recommended that manufacturers of resin and pipe, industry trade groups and the Federal government do more to alert pipeline operators to the role played by stress intensification from external forces in the premature failure of plastic pipe due to brittle-like cracking.

(3) *Effectiveness of performance monitoring of plastic pipeline systems as a way of detecting unacceptable performance in piping systems:* The NTSB's analysis noted that Federal regulations require pipeline operators to have an ongoing program to monitor the performance of their pipeline systems. However, the NTSB investigation revealed some gas pipeline operators' performance monitoring programs did not effectively collect and analyze data to determine the extent of possible hazards associated with plastic pipeline systems. The NTSB pointed out, "such a program must be adequate to detect trends as well as to identify localized problem areas, and it must be able to relate poor performance to specific factors such as plastic piping brands, dates of manufacture (or installation dates), and failure conditions."

Copies of this report may be obtained by searching the NTSB Web site at *www.ntsb.gov.*

II. Advisory Bulletins Previously Issued by PHMSA

The NTSB made several recommendations to PHMSA and to trade organizations in its 1998 special investigation report. In response, PHMSA issued three advisory bulletins. The first advisory bulletin, ADB–99–01, *Potential Failure Due to Brittle-Like Cracking of Certain Polyethylene Plastic Pipe Manufactured by Century Utility Products Inc,* was published in the **Federal Register** (FR) on March 11, 1999 (64 FR 12211) to advise natural gas pipeline distribution system operators that brittle-like cracking may occur on certain polyethylene pipe manufactured by Century Utility Products, Inc.

The second advisory bulletin, ADB–99–02, *Potential Failures Due to Brittle-Like Cracking of Older Plastic Pipe in Natural Gas Distribution Systems,* was also published in the **Federal Register** on March 11, 1999 (64 FR 12212) to advise natural gas pipeline distribution system operators of the potential for brittle-like cracking of plastic pipes installed between the 1960s and early 1980s.

The third advisory bulletin, ADB–02–07, *Notification of the Susceptibility To Premature Brittle-Like Cracking of Older Plastic Pipe,* was published in the **Federal Register** on November 26, 2002 (67 FR 70806) to reiterate to natural gas pipeline distribution system operators the susceptibility of older plastic pipe to premature brittle-like cracking. The older polyethylene pipe materials specifically identified in ADB–02–07 included, but were not limited to:

- Century Utility Products, Inc. products;
- Low-ductile inner wall "Aldyl A" piping manufactured by DuPont Company before 1973; and
- Polyethylene gas pipe designated PE 3306.

This third advisory bulletin also listed several environmental, installation and service conditions in which plastic piping is used that could lead to premature brittle-like cracking failure. PHMSA also described six recommended practices for polyethylene gas pipeline system operators to aid them with identifying and managing brittle-like cracking problems.

III. Plastic Pipe Studies

Beginning January 25, 2001, the American Gas Association (AGA) began to collect data on in-service plastic piping material failures with the objective of identifying trends in the performance of these materials. The resulting leak survey data, collected from 2001 to present, on the county's natural gas distribution systems includes both actual failure information and negative reports (reports of no leads) submitted voluntarily by participating pipeline operating companies.

The AGA, PHMSA, and other industry and state organizations continue to collect and analyze the data. Unfortunately, the data cannot be correlated with the quantities of each plastic pipe material that may be in service across the United States. Therefore, the data does not assess the failure rates of individual plastic pipe materials on a linear basis (i.e. per foot, per mile, etc.). However, the failure data reinforces what is historically known about certain older plastic piping and components. The data also indicates the susceptibility of additional specific materials to brittle-like cracking.

IV. Advisory Bulletin ADB–07–01

To: Owners and Operators of Natural Gas Pipeline Distribution Systems.

Subject: Updated Notification of the Susceptibility of Older Plastic Pipes to Premature Brittle-Like Cracking.

Advisory: All owners and operators of natural gas distribution systems who have installed and operate plastic piping are reminded of the phenomenon of brittle-like cracking. Brittle-like cracking refers to crack initiation in the pipe wall not immediately resulting in a full break followed by stable crack growth at stress levels much lower than the stress required for yielding. This results in very tight, slit-like, openings and gas leaks. Although significant cracking may occur at points of stress concentration and near improperly designed or installed fittings, small brittle-like cracks may be difficult to detect until a significant amount of gas leaks out of the pipe, and potentially migrates into an enclosed space such as a basement. Premature brittle-like cracking requires relatively high localized stress intensification that may result from geometrical discontinuities, excessive bending, improper installation of fittings, dents and/or gouges. Because this failure mode exhibits no evidence of gross yielding at the failure location, the term brittle-like cracking is used. This phenomenon is different from brittle fracture, in which the pipe failure causes fragmentation of the pipe.

All owners and operators of natural gas distribution systems are future advised to review the three earlier advisory bulletins on this issue. In addition to being available in the **Federal Register**, these advisory bulletins are available in the docket, and on PHMSA's Web site at *http://phmsa.dot.gov/* under Pipeline Safety Regulations.

In the first advisory bulletin, ADB–99–01, published on March 11, 1999 (64 FR 12211), PHMSA advises natural gas distribution system operators of the potential for poor resistance to brittle-like cracking of certain polyethylene pipe manufactured by Century Utility Products, Inc. In the second advisory bulletin, ADB–99–02, published on March 11, 1999 (64 FR 12212), PHMSA advises natural gas distribution system operators of the potential for brittle-like cracking of plastic pipes installed between the 1960s and early 1980s.

In the third advisory bulletin, ADB–02–07, published on November 26, 2002 (67 FR 70806), PHMSA reiterates to pipeline operators the susceptibility of some older plastic pipe to premature brittle-like cracking which could substantially reduce the service life of natural gas distribution systems and to explain the mission of the Plastic Pipe Database Committee (PPDC) "to develop and maintain a voluntary data collection process that supports the analysis of the frequency and causes of in-service plastic piping material failures." The advisory bulletin also lists several environmental, installation and service conditions under which plastic piping is used which is used which could lead to premature brittle-like cracking failure. PHMSA also describes six recommended practices for polyethylene gas pipeline system operators to aid them with identifying and managing brittle-like cracking problems.

Lastly, the susceptibility of some polyethylene pipes to brittle-like cracking is dependent on the resin, pipe processing, and service conditions. As noted in ADB–02–07, these older polyethylene pipe materials include, but are not limited to:

- Century Utility Products, Inc. products;
- Low-ductile inner wall "Aldyl A" piping manufactured by DuPont Company before 1973; and
- Polyethylene gas pipe designated PE 3306.

The data now supports adding the following pipe materials to this list:

- Delrin insert tap tees; and,
- Plexco service tee Celcon (polyacetal) caps.

Authority: 49 U.S.C. chapter 601 and 49 CFR 1.53.

Issued in Washington, DC, on August 28, 2007.

Jeffrey D. Wiese,

Associate Administrator for Pipeline Safety.

[FR Doc. 07–4309 Filed 9–5–07; 8:45 am]

BILLING CODE 4910–60–M

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

[Docket No. PHMSA–2007–28993]

Pipeline Safety: Adequacy of Internal Corrosion Regulations for Hazardous Liquid Pipelines

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), U.S. Department of Transportation (DOT).

ACTION: Notice of availability of materials; request for comments.

SUMMARY: This notice announces the availability of materials, including a briefing paper prepared for PHMSA's Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC) and data on risks posed by internal corrosion on hazardous liquid pipelines. PHMSA is preparing a report to Congress on the adequacy of the internal corrosion regulations for hazardous liquid pipelines. Participants at a meeting of the THLPSSC discussed issues involved in examining the adequacy of the regulations and requested additional data. PHMSA requests public comment on these matters.

DATES: Submit comments by October 9, 2007.

ADDRESSES: Comments should reference Docket No. PHMSA–2007–28993 and may be submitted in the following ways:

- *E-Gov Web site: http://www.regulations.gov.* This Web site allows the public to enter comments on any **Federal Register** notice issued by any agency. Follow the instructions for submitting comments.
- *Fax:* 1–202–493–2251.
- *Mail:* Docket Management System: U.S. Department of Transportation, Docket Operations, M–30, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590–0001.
- *Hand Delivery:* DOT Docket Management System, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590–0001 between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

Instructions: Identify the docket number, PHMSA–2007–28993, at the beginning of your comments. If you submit your comments by mail, submit two copies. To receive confirmation that PHMSA received your comments, include a self-addressed stamped postcard. Internet users may submit comments at *http://www.regulations.gov.*

Note: Comments are posted without changes or edits to *http://www.regulations.gov*, including any personal information provided. There is a privacy statement published on *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Barbara Betsock at (202) 366–4361, or by e-mail at *barbara.betsock@dot.gov.*

SUPPLEMENTARY INFORMATION: The Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 directs PHMSA to review the internal corrosion regulations in subpart H of 49 CFR part 195 to determine if they are adequate to ensure adequate protection of the public and environment and to report to Congress on the results of the review. As an initial step in the review, PHMSA consulted the THLPSSC at its meeting on July 24, 2007. The briefing paper prepared for the committee members contains preliminary data on risk history as well as questions relating to the internal corrosion regulations. This briefing paper is posted on PHMSA's pipeline Web site (*http://ops.dot.gov*) and has been placed in the docket.

At the meeting, PHMSA officials committed to gathering additional data responding to questions posed by the committee members. PHMSA has updated the data and included data responsive to the committee members. This data is also posted on the pipeline Web site and contained in the docket.

PHMSA requests comments on the adequacy of the internal corrosion regulations and answers to the questions posed in the briefing paper. PHMSA will use these comments in its review of the internal corrosion regulations.

Authority: 49 U.S.C. 60102, 60115, 60117: Sec. 22, Pub. L. 109–468, 120 Stat. 3499.

Issued in Washington, DC on August 27, 2007.

Jeffrey D. Wiese,

Associate Administrator for Pipeline Safety.

[FR Doc. E7–17538 Filed 9–5–07; 8:45 am]

BILLING CODE 4910–60–P

DEPARTMENT OF VETERANS AFFAIRS

[OMB Control No. 2900–0675]

Proposed Information Collection Activity: Proposed Collection; Comment Request

AGENCY: Center for Veterans Enterprise, Department of Veterans Affairs.

ACTION: Notice.

SUMMARY: The Center for Veterans Enterprise (CVE), Department of Veterans Affairs (VA), is announcing an opportunity for public comment on the proposed collection of certain information by the agency. Under the Paperwork Reduction Act (PRA) of 1995, Federal agencies are required to publish notice in the **Federal Register** concerning each proposed collection of information, including each proposed extension of a currently approved collection, and allow 60 days for public comment in response to the notice. This notice solicits comments for information needed to identify veteran-owned businesses.

DATES: Written comments and recommendations on the proposed collection of information should be received on or before November 5, 2007.

ADDRESSES: Submit written comments on the collection of information through *http://www.Regulations.gov;* or Gail Wegner (00VE), Department of Veterans Affairs, 810 Vermont Avenue, NW., Washington, DC 20420 or e-mail: *gail.wegner@va.gov.* Please refer to "OMB Control No. 2900–0675" in any correspondence. During the comment period, comments may be viewed online through the Federal Docket Management System (FDMS) at *http://www.Regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Gail Wegner at (202) 303–3296 or FAX (202) 254–0238.

SUPPLEMENTARY INFORMATION: Under the PRA of 1995 (Pub. L. 104–13; 44 U.S.C. 3501–3521), Federal agencies must obtain approval from the Office of Management and Budget (OMB) for each collection of information they conduct or sponsor. This request for comment is being made pursuant to section 3506(c)(2)(A) of the PRA.

With respect to the following collection of information, CVE invites comments on: (1) Whether the proposed collection of information is necessary for the proper performance of CVE's functions, including whether the information will have practical utility; (2) the accuracy of CVE's estimate of the burden of the proposed collection of

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

APPLICATION OF ATMOS ENERGY	**)**	
	)	
CORPORATION FOR AN ADJUSTMENT	**)**	**Case No. 2018-00281**
	)	
OF RATES AND TARIFF MODIFICATIONS	**)**	

RE BUTTAL TESTIMONY OF JOE T. CHRISTIAN

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Joe T. Christian. My business address is 5420 LBJ Freeway, 1600 Lincoln Centre, Dallas, TX 75240.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Atmos Energy Corporation ("Atmos Energy" or "the Company") as Director of Rates & Regulatory Affairs (Shared Services).

Q. ARE YOU THE SAME JOE CHRISTIAN THAT FILED PREFILED TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. ARE YOU SPONSORING ANY EXHIBITS AS PART OF YOUR REBUTTAL TESTIMONY?

A. Yes. I am sponsoring the following exhibits, which were prepared by me or under my direct supervision:

- Exhibit JTC-R-1 Capital Structure 2016-2018
- Exhibit JTC-R-2 Selected Responses to Discovery
- Exhibit JTC-R-3 Impact of a Rating Agency Downgrade
- Exhibit JTC-R-4 Prospectus Supplement

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to rebut the adjustments to the Company's proposed capital structure, the proposed adjustments to the Company's cash working capital as well as comment on the proposed removal of CWIP from rate base. These adjustments are all recommended by Attorney General's Office of Rate Intervention (OAG) witness Mr. Lane Kollen.

II. COST OF CAPITAL ISSUES

Q. PLEASE DESCRIBE MR. KOLLEN'S ADJUSTMENT TO THE CAPITAL STRUCTURE OF THE COMPANY?

A. Mr. Kollen recommends that the Commission cap the common equity at 54.3%, after adjustment for the October 2018 new debt issuance[1] based on a comparison to the capital structure approved in Case No. 2017-00349 and a comparison to the comparative group (aka proxy group). Mr. Kollen arrives at his recommended cap on equity, in part, by the inclusion of an October 2018 long-term debt issuance. Mr. Kollen expresses the opinion that the Company's proposed capital structure, "is unreasonable, and unnecessarily and significantly increases the cost of capital and

[1] *In Re: Application of Atmos Energy Corporation for an Adjustment of Rates and Tariff Modifications.* Direct Testimony and Exhibits of Lane Kollen, Page 41.

base revenue requirement, as well as the PRP Rider revenue requirement."[2] He goes on to indicate that the cost of common equity must be grossed-up for income taxes, making it even more costly than it appears."[3] He states that the forecast common equity ratio is excessive and the long-term debt ratio is too low and describes the proposed capital structure as "absurd".[4] Mr. Kollen expresses the opinion that failure to include the effects of a known financing in a forecast capital structure is highly unusual and questionable.[5]

Q. DO YOU AGREE WITH MR. KOLLEN'S RECOMMENDATION TO CAP THE COMMON EQUITY AT 54.3%?

A. No. Mr. Kollen's arguments for a cap on the equity component can be reduced down to the following two points: 1. A simple comparison to what was approved in the last case and 2. A comparison to the proposed capital structure to the peer group average of 53%. No other evidence or analysis is provided.

Q. DOES THE COMPANY'S PROPOSED CAPITAL STRUCTURE REFLECT ITS ACTUAL COST OF DOING BUSINESS?

A. Yes. The capital structure proposed at the time of the filing is based on its consolidated capital structure (i.e. not hypothetical or subsidiary balance) and as I indicated in my Direct Testimony (Page 8, lines 4-10) the June capital structure is

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[2] Kollen Page 40
[3] Kollen Page 40
[4] Kollen Page 41
[5] Kollen Page 42

representative of an overall capital structure that will be in effect at the time rates are implemented in this case. Therefore, no adjustment was warranted beyond the adjustment to the long-term debt refinancing that was anticipated to occur in March of 2019.[6]

Q. WHY IS IT IMPORTANT FOR THE COMPANY TO CALCULATE ITS REVENUE REQUIREMENT BASED UPON ITS ACTUAL CAPITAL STRUCTURE?

A. Safe and reliable service cannot be maintained at a reasonable cost if the Company does not have the financial flexibility and strength to access the competitive capital markets on reasonable terms. As the factors used by the credit rating agencies[7] to evaluate utilities demonstrate, relying too heavily on long-term debt financing creates risk, as does a regulatory environment that is not supportive of utilities' ability to recover their actual costs and to have the opportunity to earn a fair return on their investments.

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[6] Please note that I do provide an updated capital structure recommendation later in my rebuttal testimony.

[7] Moody's Investor Service and Standard and Poor's ("S&P"). S&P utilizes Core Ratios (FFO / Debt and Debt/EBITDA).

Q. HAS ATMOS ENERGY'S EQUITY COMPONENT OF UTILITY CAPITAL STRUCTURE INCREASED SINCE THE LAST RATE CASE?

A. Yes. As shown in Exhibit JTC-R-1 Capital Structure 2016-2018, the Company has strengthened the equity component of its capital structure. This upward movement is a result of the increased investment in infrastructure across our distribution utilities. In support of his recommendation Mr. Kollen notes that his equity cap falls within the range disclosed to investors (50%-60%) but he has failed to evaluate how this range has changed over time and where the Company has managed within the range the past three years.

Q. HOW HAS THE RANGE CHANGED BETWEEN 2012 AND 2018?

A. The ranges between fiscal years 2012 and 2018 are as follows:

Table JTC-1
Capital Structure Ranges
(inclusive of STD)

Year	Range		10K Pg
2012	50.00% ___	55.00%	47
2013	50.00% ___	55.00%	41
2014	50.00% ___	55.00%	40
2015	45.00% ___	55.00%	39
2016	45.00% ___	55.00%	38
2017	50.00% ___	60.00%	35
2018	50.00%	60.00%	32

As can be noted in the above table, the Company has raised the top of its range to 60%. This has been done to enable us to maintain our strong balance sheet and credit rating, which in turn will enable the Company to access the capital markets under more favorable conditions than if our credit metrics were diminished by having less equity in the capital structure.

Q. DO YOU BELIEVE THAT THE EQUITY COMPONENT OF UTILITY CAPITAL STRUCTURES IS TRENDING UP OR DOWN?

A. I believe the trend is upward. Utilities are working to strengthen the equity portion of their balance sheet in order to counter the impact that tax reform had on their financial metrics as well as support higher levels of capital investment.

Q. DO YOU HAVE ANY SUPPORT FOR THIS BELIEF?

A. Yes. A review of Value Line Investment Survey, March 1, 2019 for the proxy group Companies indicates a 2021-2023 average debt / equity ratio of 44% / 56%, which is higher than the 47% / 53% debt / equity ratio provided by Mr. Kollen[8] and therefore supports my belief that utilities in general, not just Atmos Energy, are maintaining a stronger equity portion of their total capitalization.

Q. DID THE COMPANY PROVIDE ANY DISCOVERY RESPONSES REGARDING WHY THE COMPANY HAS MANAGED ITS CAPITAL STRUCTURE IN A MANNER THAT RESULTS IN A HIGHER EQUITY BALANCE?

A. Yes. I have included Exhibit JTC-R-2 Selected Responses to Discovery that address and support our requested capital structure. In particular I would point to

[8] Mr. Kollen at 40

the response to AG 1-16 which stated in part, "In order to accomplish our anticipated five year financing needs, the Company has improved its credit metrics through increased equity and decreased our reliance on debt financing, in order to access the capital markets on terms that will be more favorable than if we had not improved our credit metrics in recent years."

Q. GIVEN THAT THE SUPPORTED CAPITAL STRUCTURE IS BASED ON ACTUALS; IS NECESSARY TO SUPPORT CURRENT CREDIT METRICS; AND IS REASONABLE COMPARED TO THE PEER GROUP, CAN THE COMMISSION CONCLUDE THEN THAT THE COMPANY'S CAPITAL STRUCTURE IS REASONABLE?

A. Yes. Mr. Kollen provides no substantial evidence that the Company's proposed capital structure should not be based on its actual costs. The Company's capital structure is based on its actual costs, is reflective of what is necessary to maintain its current credit metrics, and is not out of line as compared to its peer company's debt / equity ratios. Equity capital is more costly but necessary in the current capital investment and economic environment. It is not simply a means to drive the deficiency higher as Mr. Kollen's arguments imply.

Q. MOVING ON NOW TO THE LONG-TERM COST OF DEBT, DO YOU AGREE THAT THE COST OF LONG-TERM DEBT SHOULD BE ADJUSTED TO REFLECT THE OCTOBER 2018 LONG-TERM DEBT ISSUANCE?[9]

A. Yes, however I believe that all components of the capital structure should be updated, not only the impact of the October 2018 debt financing. Only updating for the October financing would ignore the impact of the incremental equity financing activities that have also occurred since the case has been filed.

Q. DO YOU AGREE THAT THE COST OF LONG-TERM DEBT SHOULD BE ADJUSTED TO MR. KOLLEN'S PROPOSED 4.392% FOR THE MARCH 2019 LONG-TERM DEBT ISSUANCE?[10]

A. No. Mr. Kollen's hypothetical rate is no longer necessary since the debt has now been issued and the actual rate of the new debt is known.[11]

Q. HAVE YOU CALCULATED THE IMPACT OF THESE FINANCING ACTIVITIES?

A. Yes. I include the impacts of these financing activities within the update to the Company's proposed capital structure discussed later in my rebuttal testimony.

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[9] Kollen Page 42. Please note that Mr. Kollen's proposal to include $600 million addition to long-term debt fails to properly exclude the repayment of short-term debt and also fails to make the appropriate adjustment to the short-term debt rate.

[10] Kollen Page 44

[11] Please see Exhibit JTC-R-4 Prospectus Supplement February 25, 2019 for Atmos Energy Corporation $450,000,000 4.125% Senior Notes due 2019.

Q. DO YOU AGREE WITH MR. KOLLEN'S CHARACTERIZATION OF THE COMPANY'S "FAILURE" TO INCLUDE THE EFFECTS OF KNOWN FINANCING IN ITS PROPOSED CAPITAL STRUCTURE?

A. No. Mr. Kollen references my response to AG 2-20, but does not provide a copy of the response as an exhibit to his testimony. In this response, included in Exhibit JTC-R-2 Selected Responses to Discovery, I indicated that I was aware of Atmos Energy's currently anticipated incremental long-term financing of $3.5 - $4.0 billion through fiscal 2022. Although I did not speak specifically to the offering I did suggest in Direct Testimony page 8, lines 11-18 that the capital structure can be updated with more current information anticipating that some of the incremental long-term financing disclosed in investor presentations could occur prior to the end of 2018. Despite this response, Mr. Kollen incorrectly believes the Company had a desire to hide financing that would be publicly known.

Q. HAVE YOU CONSIDERED UPDATING THE CAPITALIZATION TO REFLECT THE IMPACT OF THE COMPANY'S OCTOBER LONG-TERM DEBT FINANCING AND SUGGESTED MARCH REFINANCING RATE DISCUSSED BY MR. KOLLEN?

A. Yes. As I state in my Direct Testimony, page 8, lines 11-18, updating the capital structure could be appropriate in order to pick up incremental long-term debt financing along with additional equity issuances and changes in average short-term debt balances/rates and thus be more reflective of the costs that will be incurred when new base rates go in effect.

Q. HOW MUCH LONG-TERM FINANCING OCCURRED SINCE THE COMPANY FILED ITS CASE IN SEPTEMBER 2018?

A. In October 2018 and February 2019, $1.1 billion of 30-year debt was issued. In November 2018, $748 million in new equity was issued. In addition the Company recently established a new $500 million At-The-Market Equity Issuance Program. This long-term financing is done to support the important infrastructure investments across its eight-state operating area and meets the objective discussed in response to AG 1-20 of utilizing short-term debt to provide cost-effective short-term financing until it can be replaced with a balance of long-term debt and equity financing.

Q. WHAT IS THE IMPACT OF UPDATING THE CASE WITH ACTUAL CAPITAL STRUCTURE THROUGH DECEMBER 2018 WITH ITS LATEST AVAILABLE PUBLIC INFORMATION (THE MARCH 2019 REFINANCE)?

A. Updating the Capital Structure from June 2018 to December 2018, with a known and measurable adjustment for the refinancing of March 2019 debt issuance results in the overall rate of return being reduced from a requested 7.95% to 7.92% as shown in the following table:

Table JTC-2

I. Atmos Energy Cost of Capital Per Filing

	Capital Amount	Capital Ratio	Component Costs	Weighted Avg Cost
Short Term Debt	281,542,431	3.44%	2.4%	0.08%
Long Term Debt	3,131,314,703	38.31%	4.72%	1.81%
Common Equity	4,760,180,678	58.24%	10.4%	6.06%
Total Capital	8,173,037,812	100%		7.95%

II. Atmos Energy Cost of Capital Updated

	Capital Amount	Capital Ratio	Component Costs	Weighted Avg Cost
Short Term Debt	203,112,403	2.21%	3.4%	0.08%
Long Term Debt	3,659,778,860	39.73%	4.56%	1.81%
Common Equity	5,348,194,759	58.06%	10.4%	6.04%
Total Capital	9,211,086,023	100%		7.93%

Q. ARE YOU SURPRISED AT SO LITTLE CHANGE TO THE EQUITY COMPONENT OVER THE SIX MONTH PERIOD?

A. No. While there will be times that the debt portion of our balance sheet will range lower than 58% equity, in order to maintain our existing debt ratings I expect us to be in the upper quartile of our desired capital structure range of 50% - 60%[12]. If the Commission were to adopt Mr. Kollen's recommendation of capping our equity at 54.3% it would put downward pressure and possible downgrade of our debt

[12] See Exhibit JTC-R-1, Page 1 of 3. Capital Structure Charts which show the equity has been between approximately 55% and 60% since November 2017.

rating. Any downgrade would make future debt financing more costly therefore I recommend the Commission reject Mr. Kollen's recommended capital structure.

Q. CAN YOU QUANTIFY THE VALUE OF AN 'A' RATED UTILITY VS. A 'B' RATED UTILITY?

A. Yes. There is relationship between the equity and debt ratios and the cost of debt. To demonstrate this relationship, I worked with our Treasury Department to quantify the impact of a hypothetical financing of Atmos Energy's long-term debt rates and included the results in Exhibit JTC-R-3 Impact of a Rating Agency Downgrade.

Q. WHAT ARE THE RESULTS?

A. If the Company's $3.6 billion in debt were refinanced in roughly the same proportion as exists today at spreads indicated by reviewing Bond Value Yield available through Bloomberg financial services, the impact would be an increase of approximately $12.7 million annually. In other words, if the Company had a lower rating, debt costs would increase and have a negative impact on the customer.

Q. DOES THE COMPANY ANTICIPATE THE NEED TO ACCESS THE CAPITAL MARKETS OVER THE NEXT FIVE YEARS?

A. Yes. In addition to the $600 million in debt issued in October 2018, $750 million in equity issued in November 2018, and the $450 million in debt in March 2019, the Company currently anticipates incremental long-term financing of $3.5 - $4.5

billion through fiscal 2023 (including impact from TCJA). This incremental financing, along with cash flows from operations, will be utilized to finance our capital expenditures. Our priority is to issue debt and equity securities in a balanced manner that maintains a balanced capital structure with an equity-to-capitalization ratio and therefore maintain our existing credit ratings.

Q. HAS THE COMPANY INCLUDED THE UPDATED CAPITAL STRUCTURE AND DEBT COST IN THE MODEL SPONSORED BY MR. WALLER IN HIS REBUTTAL TESTIMONY?

A. Yes, the Company has included the updated capital structure with Mr. Waller's Rebuttal Testimony as Exhibit GKW-R-1.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING CAPITAL STRUCTURE AS IT RELATES TO MR. KOLLEN'S PROPOSED CWIP ADJUSTMENT?

A. Yes. The Commission considered the appropriateness of inclusion/exclusion of short-term debt in the capital structure as part of Case No. 2013-00148. In this case the Commission reasoned that it recognized that a utility's rate base included items other than long-lived plant assets that may be financed with short-term debt. Furthermore, while it is the intent of utilities, from a planning perspective, to finance long-lived assets with long-term forms of capital, from a practical perspective the Commission has long held the position that capital cannot be assigned directly to a particular state, jurisdiction or specific asset.[13]

Q. HAS THE COMPANY CONTINUED TO RELY ON SHORT-TERM DEBT AT THE LEVELS INCLUDED IN THE CASE NO. 2013-00148?

A. No. Thus, to the extent the Commission were to adopt Mr. Kollen's CWIP adjustment, I believe the Commission's decision in Case No. 2013-00148 should be reconsidered. Short-term debt may temporarily fund capital investments, such as CWIP, but it is not an appropriate source of permanent financing for long-lived assets. To the extent that the Commission believes that short-term debt is utilized to finance CWIP, then it logically follows that it should be excluded from the capitalization supporting ongoing rates.

III. CASH WORKING CAPITAL

Q. PLEASE DESCRIBE MR. KOLLEN'S ADJUSTMENT TO THE COMPANY'S CASH WORKING CAPITAL STUDY?

A. Mr. Kollen analyzes the cash working capital study filed by the Company and indicates that the Company has incorrectly included depreciation expense, deferred income tax expense, and the non-dividend component of the return on equity in the calculation of our cash working capital study and failed to correctly include the

[13] Case No. 2013-00148, *Application of Atmos Energy Corporation for an Adjustment of Rates and Tariff Modifications,* Order at 8-9. (Ky. PSC April 22, 2014).

dividend component of the return on equity with the correct number of expense lag days.[14] Mr. Kollen does not specifically state his agreement but does include in his cash working calculation the Company's calculation of the revenue lag and, except for his proposal to add the dividend component of the return on equity, expense lags.

Q. DID THE COMMISSION ADOPT THE COMPANY'S PROPOSED LEAD-LAG STUDY IN CASE NO. 2017-00349?

A. Yes.[15] In light of the Commission's order in Case No. 2017-00349, as noted in my Direct Testimony, the inclusion of a lead-lag study following the same methodology has been filed in this case. I would also ask the Commission to recall that the lead-lag methodology adopted in the previous case follows the same methodologies performed by the Company in its Tennessee operations.[16]

Q. IS DEPRECIATION EXPENSE PROPERLY INCLUDED IN THE LEAD-LAG STUDY?

A. Yes. As I indicated in my Direct Testimony, the payment for the asset precedes the receipt of service from the asset and the recording of depreciation expense. The lag

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[14] Kollen Direct at page 36

[15] *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates and Tariff Modifications,* Case No. 2017-00349, Order Entered May 3, 2018, Page 16-17.

[16] *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates and Tariff Modifications*, Case No. 2017-00349, Rebuttal Testimony of Joe T. Christian, Page 13

between payment for the asset and the recording of depreciation expense is recognized by the including net plant in service in rate base.

Q. DOES INCLUSION OF PLANT IN SERVICE IN RATE BASE SUFFICE TO PROPERLY ACCOUNT FOR THE ENTIRE LAG RELATING TO DEPRECIATION?

A. No. The inclusion in rate base of plant in service does not recognize the subsequent lag from the provision of service to the receipt of cash for that service. By including depreciation expense in the lead-lag study with a zero expense lag, the lead-lag study properly recognizes the subsequent revenue lag on recovering cash related to investment in plant assets. In other words, the investment in an asset is included in rate base as net plant in service until depreciation is recorded on that asset. Recording depreciation removes the asset from rate base, even though cash has not been received to pay for the service provided by the asset, unless the revenue lag on depreciation expense is included in cash working capital through the lead-lag study.

Q. IS THE RETURN OF NON-CASH EXPENSE ADDRESSED BY INCLUSION OF THESE ITEMS IN RATE BASE AND SUBTRACTING ACCUMULATED DEPRECIATION AND ACCUMULATED DEFERRED INCOME TAXES ON A LAGGED BASIS TO ALLOW THE COMPANY RETAINAGE OF THE CARRYING CHARGE VALUE OF NON-CASH EXPENSES BETWEEN RATE CASES AS MR. KOLLEN SUGGESTS ON PAGE 37 OF THIS TESTIMONY?

A. No. The test period the Company utilizes is a forward looking rate base and therefore the average investment is reflected in the rate base component so no lag on depreciated investment or accumulated deferred income taxes is experienced during the test period. Moreover, to the extent the Company does not file a rate case each and every twelve months and rate base is increasing, lag on the new investment more than off-sets any lag that occurs due to depreciating investment or changes in deferred income taxes.

Q. IS MR. KOLLEN CORRECT IN DIVIDING THE RETURN ON EQUITY INTO TWO COMPONENTS TO AND CALCULATING A LAG ON THE DIVIDEND PAYMENT APPROPRIATE AS HE SUGGESTS ON PAGE 38 OF HIS TESTIMONY?

A. As indicated in my Direct Testimony, operating income is earned through the provision of utility service. There is again a revenue lag between the provision of service and the receipt of cash for that service. Mr. Kollen does not dispute that derivation of the rates billed to customers includes a return component, and furthermore he does not address the fundamental premise that the shareholder gets to wait 40.82 days from the time service is provided by the company until revenue related to that service is available to the Company. His calculation of an expense lag of 118.6 days (comprised of a service period of 45.6 days plus 73 days after the end of a quarter) is an unnecessary distraction.[17] To suggest that shareholders should have rate base reduced to reflect a payment to the shareholder is puzzling.

Q. SHOULD THE COMMISSION RETAIN THE METHODOLOGY FROM THE LAST CASE IN DETERMINING THE APPROPRIATE CASH WORKING CAPITAL?

A. Yes. Mr. Kollen's testimony varies some from the previous case, however no new evidence has been offered therefore I believe the Commission's finding in this case should be based upon the lead/lag study that was filed and supported in my Direct Testimony.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

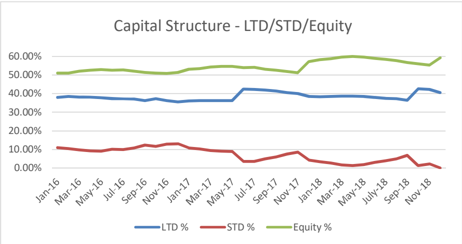
[17] Mr. Kollen discusses the DCF model as the basis for his split but provides no testimony in support of three percent being the appropriate split between dividend return and projected growth in stock price.

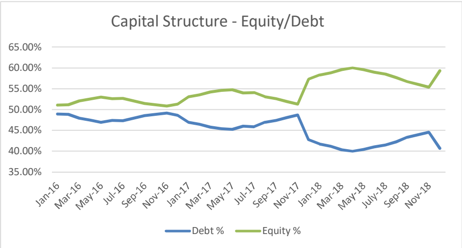
Atmos Energy Corporation
Capital Structure by Component
Total Company
For the Period January 2016 - December 2018

Description	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Long-Term Debt (Including Current Maturities)	$ 2,455,502,231	$ 2,455,530,754	$ 2,455,559,278	$ 2,455,587,801	$ 2,455,616,325	$ 2,455,644,849	$ 2,455,673,372	$ 2,455,701,896	$ 2,438,778,635	$ 2,563,918,889	$ 2,564,059,143	$ 2,564,199,396
Notes Payable	708,711,351	666,441,027	626,928,501	600,119,181	588,760,748	670,465,758	660,469,447	713,363,904	829,811,164	800,464,658	909,674,672	940,746,591
Total Shareholders' Equity	3,299,031,455	3,267,084,384	3,344,565,075	3,383,622,256	3,436,952,412	3,466,723,837	3,472,256,616	3,438,618,783	3,463,058,963	3,520,473,562	3,595,033,060	3,698,975,167
Total Capitalization Including Short-Term Debt	$ 6,463,245,037	$ 6,389,056,165	$ 6,427,052,855	$ 6,439,329,238	$ 6,481,329,485	$ 6,592,834,444	$ 6,588,399,435	$ 6,607,684,583	$ 6,731,648,763	$ 6,884,857,110	$ 7,068,766,875	$ 7,203,921,154

Description	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
LTD %	37.99%	38.43%	38.21%	38.13%	37.89%	37.25%	37.27%	37.16%	36.23%	37.24%	36.27%	35.59%
STD %	10.97%	10.43%	9.75%	9.32%	9.08%	10.17%	10.02%	10.80%	12.33%	11.63%	12.87%	13.06%
Equity %	51.04%	51.14%	52.04%	52.55%	53.03%	52.58%	52.70%	52.04%	51.44%	51.13%	50.86%	51.35%
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Description	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Debt %	48.96%	48.86%	47.96%	47.45%	46.97%	47.42%	47.30%	47.96%	48.56%	48.87%	49.14%	48.65%
Equity %	51.04%	51.14%	52.04%	52.55%	53.03%	52.58%	52.70%	52.04%	51.44%	51.13%	50.86%	51.35%
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%





Atmos Energy Corporation
Capital Structure by Component
Total Company
For the Period January 2016 - December 2018

Description	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Long-Term Debt (Including Current Maturities)	$ 2,564,339,650	$ 2,564,479,903	$ 2,564,620,157	$ 2,564,760,410	$ 2,564,900,664	$ 3,066,734,196	$ 3,066,772,609	$ 3,066,904,471	$ 3,067,045,495	$ 3,067,186,078	$ 3,067,327,541	$ 3,067,468,564
Notes Payable	775,069,471	724,278,560	670,606,792	644,134,763	629,857,850	258,573,383	262,202,530	362,721,572	447,745,269	572,550,585	657,589,374	336,816,271
Total Shareholders' Equity	3,778,803,299	3,790,503,944	3,834,864,598	3,861,648,697	3,864,281,638	3,901,710,103	3,923,183,120	3,876,930,951	3,898,665,243	3,933,727,046	3,925,107,994	4,563,619,782
Total Capitalization Including Short-Term Debt	$ 7,118,212,420	$ 7,079,262,407	$ 7,070,091,547	$ 7,070,543,870	$ 7,059,040,151	$ 7,227,017,682	$ 7,252,158,259	$ 7,306,556,994	$ 7,413,456,006	$ 7,573,463,709	$ 7,650,024,909	$ 7,967,904,617

Description	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
LTD %	36.03%	36.23%	36.27%	36.27%	36.33%	42.43%	42.29%	41.97%	41.37%	40.50%	40.10%	38.50%
STD %	10.89%	10.23%	9.49%	9.11%	8.92%	3.58%	3.62%	4.96%	6.04%	7.56%	8.60%	4.23%
Equity %	53.09%	53.54%	54.24%	54.62%	54.74%	53.99%	54.10%	53.06%	52.59%	51.94%	51.31%	57.28%
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Description	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Debt %	46.91%	46.46%	45.76%	45.38%	45.26%	46.01%	45.90%	46.94%	47.41%	48.06%	48.69%	42.72%
Equity %	53.09%	53.54%	54.24%	54.62%	54.74%	53.99%	54.10%	53.06%	52.59%	51.94%	51.31%	57.28%
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Atmos Energy Corporation
Capital Structure by Component
Total Company
For the Period January 2016 - December 2018

Description	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	July-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Long-Term Debt (Including Current Maturities)	$ 3,067,609,587	$ 3,067,750,610	$ 3,067,891,633	$ 3,068,032,657	$ 3,068,173,680	$ 3,068,314,703	$ 3,068,455,726	$ 3,068,596,749	$ 3,068,665,052	$ 3,659,621,827	$ 3,659,788,710	$ 3,659,778,860
Notes Payable	268,675,525	215,748,079	129,601,816	109,795,722	143,846,586	244,777,193	324,774,078	408,654,985	575,779,937	115,449,353	199,059,610	-
Total Shareholders' Equity	4,666,561,070	4,695,448,924	4,721,346,388	4,768,024,509	4,738,600,109	4,759,551,416	4,787,700,136	4,744,139,704	4,769,951,328	4,811,259,861	4,793,531,202	5,348,194,759
Total Capitalization Including Short-Term Debt	$ 8,002,846,182	$ 7,978,947,613	$ 7,918,839,837	$ 7,945,852,888	$ 7,950,620,375	$ 8,072,643,312	$ 8,180,929,940	$ 8,221,391,438	$ 8,414,396,318	$ 8,586,331,041	$ 8,652,379,522	$ 9,007,973,619

Description	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	July-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
LTD %	38.33%	38.45%	38.74%	38.61%	38.59%	38.01%	37.51%	37.32%	36.47%	42.62%	42.30%	40.63%
STD %	3.36%	2.70%	1.64%	1.38%	1.81%	3.03%	3.97%	4.97%	6.84%	1.34%	2.30%	0.00%
Equity %	58.31%	58.85%	59.62%	60.01%	59.60%	58.96%	58.52%	57.70%	56.69%	56.03%	55.40%	59.37%
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Description	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	July-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Debt %	41.69%	41.15%	40.38%	39.99%	40.40%	41.04%	41.48%	42.30%	43.31%	43.97%	44.60%	40.63%
Equity %	58.31%	58.85%	59.62%	60.01%	59.60%	58.96%	58.52%	57.70%	56.69%	56.03%	55.40%	59.37%
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Case No. 2018-00281
Atmos Energy Corporation, Kentucky Division
Staff DR Set No. 2
Question No. 2-33
Page 1 of 1

REQUEST:

Refer to the Direct Testimony of Joe T. Christian (Christian Testimony), page 6, lines 21-23 and continued on page 7, lines 1-6. Also refer to FR 16(8)(j).

a. Mr. Christian states that the capital structure on FR 16(8)(j) is Atmos's period end actual capital structure as of June 30, 2018. The dates listed on FR 16(8)(j) do not refer to June 30, 2018. Reconcile this discrepancy.

b. Explain why Atmos proposes to use the capital structure as of June 30, 2018, for the forecasted test period as opposed to the 13-month average.

c. Mr. Christian references FR 16(8)(j), column (G) stating that for the proposed capital structure, short-term debt comprises 3.44 percent, long-term debt comprises 38.39 percent, and equity is 58.17 percent.

(1) Column (G) on Schedule J-1 of FR 16(8)(j) states that longterm debt comprises 38.31 percent of the total. Reconcile this difference.

(2) Column (G) on Schedule J-1 of FR 16(8)(j) states that equity is 58.24 percent of the total. Reconcile this difference.

RESPONSE:

a. The base period for the filing, as identified by Mr. Waller on page 5, lines 1-3 of his direct testimony, is January 1, 2018 - December 31, 2018. As Mr. Christian explains in his testimony, beginning on page 7, line 1, the actual capital structure for the period ended June 30, 2018 is representative of the capital structure that will be in effect during the forecast period thus is used as a proxy for the base period identified in FR 16(8)(j).

b. The Company proposes to use the period end capital structure because it is more representative of the capital structure that will be in effect during the forecast period. The Company issued equity in the amount of $394 million in November 2017 and going forward anticipates maintaining an overall equity balance in the upper end of its equity-to-capitalization range disclosed in its public filings. The June 30, 2018 balance of 58.24% is the approximate mid-point of this range and thus appropriate for use in this case.

c. (1) Mr. Christian will update his testimony to reflect the long-term debt on FR 16(8)(j) of 38.31 percent.

(2) Mr. Christian will update his testimony to reflect the equity on FR 16(8)(j) of 58.24%.

Respondent: Joe Christian

Case No. 2018-00281
Atmos Energy Corporation, Kentucky Division
Staff DR Set No. 2
Question No. 2-34
Page 1 of 1

REQUEST:

Refer to the Christian Testimony, page 7, lines 13-18.

a. Provide a detailed list and cost support for all of the costs associated with the incremental long-term debt hedge instruments.

b. Refer to FR 16(8)(j), Schedule J-3. Provide support for the 5.07 percent interest rate for the refinance of the 8.5 percent Sr. Note due March 15, 2019.

    (1) Explain why the refinance of the 8.5 percent Sr. Note due March 15, 2019, is included in the base period.

c. Confirm that Atmos will be filing a financing application for the anticipated financing. If confirmed, provide the anticipated filing date.

RESPONSE:

a. There were not any initial costs associated with the March 2019 hedges. All economic impacts are included in the hedged rate and are paid out when settled.

b. Please see the Company's response to Staff DR No. 1-64, "Staff_1-64_Att1 - Christian WP - Hypothetical Refinance 03-2019.xlsx" for support of the costs associate with the incremental long-term.

    (1) The refinance of the 8.5 percent Sr. Note due March 15, 2019 should not have been included in the base period. Please see Attachment 1 for a copy of the updated FR 16(8)(j) and Attachment 2 for the supporting long-term debt balance and rate used in the update.

c. The Company filed an "Application for Order Authorizing Implementation of $3,000,000,000 Universal Shelf Registration" on August 21, 2018 (Case No. 2018-00280). The application was approved by the Commission on September 19, 2018. This refinancing will occur under the authority of Case No. 2018-00280.

ATTACHMENTS:

ATTACHMENT 1 - Atmos Energy Corporation, Staff_2-34_Att1 - FR_16(8)(j)_Att2 - Schedule J Updated.xlsx, 8 Pages.

ATTACHMENT 2 - Atmos Energy Corporation, Staff_2-34_Att2 - Capital Structure 06-30-18_Consolidated_LTD Support.xlsm, 49 Pages.

Respondent: Joe Christian

Case No. 2018-00281
Atmos Energy Corporation, Kentucky Division
Staff DR Set No. 2
Question No. 2-59
Page 1 of 1

REQUEST:

Refer to the application generally, and provide the most current earned ROE and the most recently awarded ROE with the date of the award for all of Atmos's distribution utilities.

RESPONSE:

Please see the most recent Atmos Energy 10-K, page 7, publicly available on the Company's website at http://www.investquest.com/iq/a/ato/fin/10k/index.htm for the most recently awarded ROE.

The most current available earned return for jurisdictions where the calculation is performed as part of earnings monitoring reports or rate models is as follows:

State	Filing	ROE	ROR
Colorado			8.07%
Louisiana	TLA	10.91%	
Louisiana	LGS	9.71%	
Mississippi		8.58%	
Tennessee			8.19%
Texas	Mid-Tex		6.77%
Texas	WT		6.89
Virginia	AIF	10.08%	

The Company does not have earned returns available for its distribution utilities that are not listed in the chart above.

Respondent: Joe Christian

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended September 30, 2018

OR

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

For the transition period from to

Commission file number 1-10042

Atmos Energy Corporation

(Exact name of registrant as specified in its charter)

Texas and Virginia	**75-1743247**
(State or other jurisdiction of incorporation or organization)	*(IRS employer identification no.)*
Three Lincoln Centre, Suite 1800 **5430 LBJ Freeway, Dallas, Texas**	**75240**
(Address of principal executive offices)	*(Zip code)*

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Definitive Proxy Statement to be filed for the Annual Meeting of Shareholders on February 6, 2019 are incorporated by reference into Part III of this report.

Currently, our distribution divisions utilize 38 pipeline transportation companies, both interstate and intrastate, to transport our natural gas. The pipeline transportation agreements are firm and many of them have “pipeline no-notice” storage service, which provides for daily balancing between system requirements and nominated flowing supplies. These agreements have been negotiated with the shortest term necessary while still maintaining our right of first refusal. The natural gas supply for our Mid-Tex Division is delivered primarily by our Atmos Pipeline — Texas Division (APT).

To maintain our deliveries to high priority customers, we have the ability, and have exercised our right, to curtail deliveries to certain customers under the terms of interruptible contracts or applicable state regulations or statutes. Our customers’ demand on our system is not necessarily indicative of our ability to meet current or anticipated market demands or immediate delivery requirements because of factors such as the physical limitations of gathering, storage and transmission systems, the duration and severity of cold weather, the availability of gas reserves from our suppliers, the ability to purchase additional supplies on a short-term basis and actions by federal and state regulatory authorities. Curtailment rights provide us the flexibility to meet the human-needs requirements of our customers on a firm basis. Priority allocations imposed by federal and state regulatory agencies, as well as other factors beyond our control, may affect our ability to meet the demands of our customers. We do not anticipate any problems with obtaining additional gas supply as needed for our customers.

Pipeline and Storage Segment Overview

Our pipeline and storage segment consists of the pipeline and storage operations of APT and our natural gas transmission operations in Louisiana. APT is one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas-producing areas of central, northern and eastern Texas, extending into or near the major producing areas of the Barnett Shale, the Texas Gulf Coast and the Delaware and Val Verde Basins of West Texas. Through its system, APT provides transportation and storage services to our Mid-Tex Division, other third party local distribution companies, industrial and electric generation customers, marketers and producers. As part of its pipeline operations, APT owns and operates five underground storage reservoirs in Texas.

Revenues earned from transportation and storage services for APT are subject to traditional ratemaking governed by the RRC. Rates are updated through periodic filings made under Texas’ Gas Reliability Infrastructure Program (GRIP). GRIP allows us to include in our rate base annually approved capital costs incurred in the prior calendar year provided that we file a complete rate case at least once every five years; the most recent of which was completed in August 2017. APT’s existing regulatory mechanisms allow certain transportation and storage services to be provided under market-based rates.

Our natural gas transmission operations in Louisiana are comprised of a proprietary 21-mile pipeline located in the New Orleans, Louisiana area that is primarily used to aggregate gas supply for our distribution division in Louisiana under a long-term contract and on a more limited basis, to third parties. The demand fee charged to our Louisiana distribution division for these services is subject to regulatory approval by the Louisiana Public Service Commission. We also manage two asset management plans in Louisiana that serve distribution affiliates of the Company, which have been approved by applicable state regulatory commissions. Generally, these asset management plans require us to share with our distribution customers a significant portion of the cost savings earned from these arrangements.

Natural Gas Marketing Segment Overview

Through December 31, 2016, we were engaged in a nonregulated natural gas marketing business, which was conducted by Atmos Energy Marketing (AEM). AEM’s primary business was to aggregate and purchase gas supply, arrange transportation and storage logistics and ultimately deliver gas to customers at competitive prices. Additionally, AEM utilized proprietary and customer-owned transportation and storage assets to provide various services to its customers requested.

As more fully described in Note 15, effective January 1, 2017, we sold all of the equity interests of AEM to CenterPoint Energy Services, Inc. (CES), a subsidiary of CenterPoint Energy Inc. As a result of the sale, Atmos Energy has fully exited the nonregulated natural gas marketing business. Accordingly, these operations have been reported as discontinued operations.

Ratemaking Activity

Overview

The method of determining regulated rates varies among the states in which our regulated businesses operate. The regulatory authorities have the responsibility of ensuring that utilities in their jurisdictions operate in the best interests of customers while providing utility companies the opportunity to earn a reasonable return on their investment. Generally, each regulatory authority reviews rate requests and establishes a rate structure intended to generate revenue sufficient to cover the costs of conducting business, including a reasonable return on invested capital.

Our rate strategy focuses on reducing or eliminating regulatory lag, obtaining adequate returns and providing stable, predictable margins, which benefit both our customers and the Company. As a result of our ratemaking efforts in recent years, Atmos Energy has:

- Formula rate mechanisms in place in four states that provide for an annual rate review and adjustment to rates.

- Infrastructure programs in place in the majority of our states that provide for an annual adjustment to rates for qualifying capital expenditures. Through our annual formula rate mechanisms and infrastructure programs, we have the ability to recover over 85 percent of our capital expenditures within six months and 99 percent within twelve months.
- Authorization in tariffs, statute or commission rules that allows us to defer certain elements of our cost of service such as depreciation, ad valorem taxes and pension costs, until they are included in rates.
- WNA mechanisms in seven states that serve to minimize the effects of weather on approximately 97 percent of our distribution Contribution Margin.
- The ability to recover the gas cost portion of bad debts in five states.

The following table provides a jurisdictional rate summary for our regulated operations as of September 30, 2018. This information is for regulatory purposes only and may not be representative of our actual financial position.

Division	Jurisdiction	Effective Date of Last Rate/ GRIP Action	Rate Base (thousands)(1)	Authorized Rate of Return(1)	Authorized Debt/ Equity Ratio	Authorized Return on Equity(1)
Atmos Pipeline — Texas	Texas	05/22/2018	$2,122,194	8.87%	47/53	11.50%
Colorado-Kansas	Colorado	05/03/2018	134,726	7.55%	44/56	9.45%
	Colorado SSIR	01/01/2018	29,855	7.82%	48/52	9.60%
	Kansas	03/17/2016	200,564	(3)	(3)	(3)
	Kansas GSRS	02/27/2018	12,514	(3)	(3)	(3)
Kentucky/Mid-States	Kentucky	05/03/2018	427,646	7.41%	47/53	9.70%
	Tennessee(8)	06/01/2017	302,953	7.49%	47/53	9.80%
	Virginia	12/27/2016	47,581	(3)	(3)	(3)
Louisiana	Trans La	05/01/2018	169,120	7.26%	49/51	9.80%
	LGS	07/01/2018	419,080	7.55%	44/56	9.80%
Mid-Tex Cities	Texas(9)	06/01/2017	2,362,937(2)	8.36%	45/55	10.50%
Mid-Tex — Dallas	Texas	02/14/2018	(3)	(3)	(3)	(3)
Mississippi	Mississippi(7)	01/01/2018	377,954	7.47%	47/53	9.67%
	Mississippi - SIR(7)	01/01/2018	70,141	7.60%	47/53	9.92%
	Mississippi - SGR	01/01/2018	23,718	8.70%	47/53	12.00%
West Texas(4)	Texas(10)	03/15/2017	(3)	(3)	(3)	10.50%
	Texas-GRIP	06/05/2018	507,831	8.57%	48/52	10.50%

Division	Jurisdiction	Bad Debt Rider(5)	Formula Rate	Infrastructure Mechanism	Performance Based Rate Program(6)	WNA Period
Atmos Pipeline — Texas	Texas	No	Yes	Yes	N/A	N/A
Colorado-Kansas	Colorado	No	No	Yes	No	N/A
	Kansas	Yes	No	Yes	No	October-May
Kentucky/Mid-States	Kentucky	Yes	No	No	Yes	November-April
	Tennessee	Yes	Yes	No	Yes	October-April
	Virginia	Yes	No	Yes	No	January-December
Louisiana	Trans La	No	Yes	Yes	No	December-March
	LGS	No	Yes	Yes	No	December-March
Mid-Tex Cities	Texas	Yes	Yes	Yes	No	November-April
Mid-Tex — Dallas	Texas	Yes	Yes	Yes	No	November-April
Mississippi	Mississippi	No	Yes	Yes	Yes	November-April
West Texas(4)	Texas	Yes	Yes	Yes	No	October-May

(1) The rate base, authorized rate of return and authorized return on equity presented in this table are those from the most recent regulatory filing for each jurisdiction. These rate bases, rates of return and returns on equity are not necessarily indicative of current or future rate bases, rates of return or returns on equity.
(2) The Mid-Tex rate base represents a "system-wide", or 100 percent, of the Mid-Tex Division's rate base.
(3) A rate base, rate of return, return on equity or debt/equity ratio was not included in the respective state commission's final decision.
(4) The West Texas Cities includes all West Texas Division cities except Amarillo, Channing, Dalhart and Lubbock.
(5) The bad debt rider allows us to recover from ratepayers the gas cost portion of uncollectible accounts.
(6) The performance-based rate program provides incentives to distribution companies to minimize purchased gas costs by allowing the companies and their customers to share the purchased gas costs savings.
(7) The Mississippi Public Service Commission approved a settlement at its meeting on October 23, 2018, which included a rate base of $541.7 million, an authorized return of 7.81%, a debt/equity ratio of 45/55 and an authorized ROE of 10.24%. New rates were implemented November 1, 2018.
(8) The Tennessee Public Utility Commission approved the Formula Rate Mechanism filing at its meeting on October 15, 2018, which included a rate base of $351.8 million, an authorized return of 7.26%, a debt/equity ratio of 49/51 and an authorized ROE of 9.8%.
(9) The Mid-Tex Cities approved the Formula Rate Mechanism filing with rates effective October 1, 2018, which included a rate base of $2,587.3 million, an authorized return of 7.87%, a debt/equity ratio of 42/58 and an authorized ROE of 9.80%.
(10) The West Texas Cities approved the Formula Rate Mechanism filing with rates effective October 1, 2018, which included a rate base of $505.7 million, an authorized return of 7.87%, a debt/equity ratio of 42/58 and an authorized ROE of 9.80%.

Although substantial progress has been made in recent years to improve rate design and recovery of investment across our service areas, we are continuing to seek improvements in rate design to address cost variations and pursue tariffs that reduce regulatory lag associated with investments. Further, potential changes in federal energy policy, federal safety regulations and changing economic conditions will necessitate continued vigilance by the Company and our regulators in meeting the challenges presented by these external factors.

Recent Ratemaking Activity

Net operating income increases resulting from ratemaking activity totaling $80.1 million, $104.2 million and $122.5 million, became effective in fiscal 2018, 2017 and 2016, as summarized below. The ratemaking outcomes for fiscal 2018 include the effect of tax reform legislation enacted effective January 1, 2018 and do not reflect the true economic benefit of the outcomes because they do not include the corresponding income tax benefit we will receive due to the decrease in our statutory tax rate.

Rate Action	Annual Increase (Decrease) to Operating Income For the Fiscal Year Ended September 30 2018	2017	2016
		(In thousands)	
Annual formula rate mechanisms	$ 92,472	$ 90,427	$ 114,974
Rate case filings	(12,853)	12,961	7,716
Other ratemaking activity	457	784	(183)
	$ 80,076	$ 104,172	$ 122,507

Additionally, the following ratemaking efforts seeking $52.8 million in annual operating income were initiated during fiscal 2018 but had not been completed as of September 30, 2018:

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Mid-Tex	Formula Rate Mechanism	Mid-Tex Cities (1) (2)	$ 28,036
Mid-Tex	Rate Case	ATM Cities (1)	4,252
Mid-Tex	Rate Case	Environs (1) (7)	(1,875)
Mississippi	Infrastructure Mechanism	Mississippi (1) (3)	7,976
Mississippi	Formula Rate Mechanism	Mississippi (1) (3)	4,119
Kentucky/Mid-States	Formula Rate Mechanism	Tennessee (1) (4)	(5,032)
Kentucky/Mid-States	Formula Rate Mechanism True-Up	Tennessee (1) (5)	(3,220)
Kentucky/Mid-States	Rate Case	Kentucky (1)	14,424
Kentucky/Mid-States	Rate Case	Virginia (1)	605
West Texas	Formula Rate Mechanism	WT Cities (1) (6)	4,030
West Texas	Rate Case	Environs (1) (7)	(485)
			$ 52,830

(1) The filing amount reflects a 21% federal income tax rate resulting from the Tax Cuts and Jobs Act of 2017 (TCJA).
(2) The Mid-Tex Cities approved a rate increase of $17.6 million effective October 1, 2018.
(3) The Mississippi Public Service Commission approved a settlement at its meeting on October 23, 2018, for a combined $7.0 million increase. New rates were implemented November 1, 2018.
(4) The Tennessee Public Utility Commission approved the Formula Rate Mechanism filing, which included $0.4 million related to the May 2017 true-up, at its October 15, 2018 meeting.
(5) The Tennessee Formula Rate Mechanism Test Period Ended May 2018 reflects the discontinuance of the prior year true-up.
(6) The West Texas Cities approved a rate increase of $2.8 million effective October 1, 2018.
(7) Settlement pending Texas Railroad Commission approval.

Our recent ratemaking activity is discussed in greater detail below.

Annual Formula Rate Mechanisms

As an instrument to reduce regulatory lag, formula rate mechanisms allow us to refresh our rates on an annual basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. The following table summarizes our annual formula rate mechanisms by state.

	Annual Formula Rate Mechanisms	
State	**Infrastructure Programs**	**Formula Rate Mechanisms**
Colorado	System Safety and Integrity Rider (SSIR)	—
Kansas	Gas System Reliability Surcharge (GSRS)	—
Kentucky	Pipeline Replacement Program (PRP)	—
Louisiana	(1)	Rate Stabilization Clause (RSC)
Mississippi	System Integrity Rider (SIR)	Stable Rate Filing (SRF), Supplemental Growth Filing (SGR)
Tennessee	—	Annual Rate Mechanism (ARM)
Texas	Gas Reliability Infrastructure Program (GRIP), (1)	Dallas Annual Rate Review (DARR), Rate Review Mechanism (RRM)
Virginia	Steps to Advance Virginia Energy (SAVE)	—

(1) Infrastructure mechanisms in Texas and Louisiana allow for the deferral of all expenses associated with capital expenditures incurred pursuant to these rules, which primarily consists of interest, depreciation and other taxes (Texas only), until the next rate proceeding (rate case or annual rate filing), at which time investment and costs would be recoverable through base rates.

The following table summarizes our annual formula rate mechanisms with effective dates during the fiscal years ended September 30, 2018, 2017 and 2016:

Division	Jurisdiction	Test Year Ended	Increase (Decrease) in Annual Operating Income (In thousands)	Effective Date
2018 Filings:				
Louisiana	LGS[1]	12/2017	$ (1,521)	07/01/2018
West Texas	Amarillo, Lubbock, Dalhart and Channing[1]	12/2017	4,418	06/08/2018
Mid-Tex	Environs[1]	12/2017	1,604	06/05/2018
West Texas	Environs[1]	12/2017	826	06/05/2018
Atmos Pipeline - Texas	Texas[1]	12/2017	42,173	05/22/2018
Louisiana	Trans La[1]	09/2017	(1,913)	05/01/2018
Colorado-Kansas	Kansas GSRS	09/2018	820	02/27/2018
Mississippi	Mississippi - SIR	10/2018	7,658	01/01/2018
Mississippi	Mississippi - SGR [2]	10/2018	1,245	01/01/2018
Mississippi	Mississippi - SRF [2]	10/2018	—	01/01/2018
Colorado-Kansas	Colorado SSIR	12/2018	2,228	12/20/2017
Atmos Pipeline - Texas	Texas	12/2016	28,988	12/05/2017
Kentucky/Mid-States	Kentucky - PRP	09/2018	5,638	10/27/2017
Kentucky/Mid-States	Virginia - SAVE [3]	09/2017	308	10/01/2017
Total 2018 Filings			$ 92,472	
2017 Filings:				
Louisiana	LGS	12/2016	$ 6,237	07/01/2017
Mid-Tex	Mid-Tex DARR	09/2016	9,672	06/01/2017
Mid-Tex	Mid-Tex Cities RRM	12/2016	36,239	06/01/2017
Kentucky/Mid-States	Tennessee ARM	05/2018	6,740	06/01/2017
Mid-Tex	Mid-Tex Environs	12/2016	1,568	05/23/2017
West Texas	West Texas Environs	12/2016	872	05/23/2017
West Texas	West Texas ALDC	12/2016	4,682	04/25/2017
Louisiana	Trans La	09/2016	4,392	04/01/2017
West Texas	West Texas Cities RRM	09/2016	4,255	03/15/2017
Colorado-Kansas	Kansas	09/2016	801	02/09/2017
Mississippi	Mississippi - SRF	10/2017	4,390	02/01/2017
Mississippi	Mississippi - SIR	10/2017	3,334	01/01/2017
Mississippi	Mississippi - SGR	10/2017	1,292	01/01/2017
Colorado-Kansas	Colorado - SSIR	12/2017	1,350	01/01/2017
Kentucky/Mid-States	Kentucky - PRP	09/2017	4,981	10/14/2016
Kentucky/Mid-States	Virginia - SAVE	09/2017	(378)	10/01/2016
Total 2017 Filings			$ 90,427	
2016 Filings:				
Louisiana	LGS	12/2015	$ 8,686	07/01/2016
Kentucky/Mid-States	Tennessee	05/2017	4,888	06/01/2016
Mid-Tex	Mid-Tex Cities RRM	12/2015	25,816	06/01/2016

Mid-Tex	Mid-Tex DARR	09/2015	5,429	06/01/2016
Mid-Tex	Mid-Tex Environs	12/2015	1,325	05/03/2016
Atmos Pipeline - Texas	Texas	12/2015	40,658	05/03/2016
West Texas	West Texas Environs	12/2015	646	05/03/2016
West Texas	West Texas ALDC	12/2015	3,484	04/26/2016
Louisiana	Trans La	09/2015	6,216	04/01/2016
Colorado-Kansas	Colorado	12/2016	764	01/01/2016
Mississippi	Mississippi - SRF	10/2016	9,192	01/01/2016
Mississippi	Mississippi - SGR	10/2016	250	12/01/2015
Kentucky/Mid-States	Kentucky - PRP	09/2016	3,786	10/01/2015
Kentucky/Mid-States	Virginia - SAVE	09/2016	118	10/01/2015
West Texas	West Texas Cities	09/2015	3,716	10/01/2015
Total 2016 Filings			$ 114,974	

(1) The operating income reflects a 21% federal income tax rate resulting from the TCJA.
(2) In our next SRF filing, the SGR rate base will be combined with the SRF rate base, per Commission order.
(3) The Company completed our Steps to Advance Virginia Energy (SAVE) program. On October 1, 2017 a refund factor was removed from the rate resulting in an operating income increase of $0.3 million.

Rate Case Filings

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a "show cause" action. Adequate rates are intended to provide for recovery of the Company's costs as well as a fair rate of return to our shareholders and ensure that we continue to safely deliver reliable, reasonably priced natural gas service to our customers. The following table summarizes our recent rate cases:

Division	State	Increase (Decrease) in Annual Operating Income (In thousands)	Effective Date
2018 Rate Case Filings:			
Colorado-Kansas	Colorado (1)	$ (241)	05/03/2018
Kentucky/Mid-States	Kentucky (1)	(7,504)	05/03/2018
Mid-Tex	City of Dallas (1)	(5,108)	02/14/2018
Total 2018 Rate Case Filings		$ (12,853)	
2017 Rate Case Filings:			
Atmos Pipeline - Texas	Texas	$ 12,955	08/01/2017
Kentucky/Mid-States	Virginia	6	12/27/2016
Total 2017 Rate Case Filings		$ 12,961	
2016 Rate Case Filings:			
Kentucky/Mid-States	Kentucky	$ 2,723	08/15/2016
Kentucky/Mid-States	Virginia	537	04/01/2016
Colorado-Kansas	Kansas	2,372	03/17/2016
Colorado-Kansas	Colorado	2,084	01/01/2016
Total 2016 Rate Case Filings		$ 7,716	

(1) The operating income reflects a 21% federal income tax rate resulting from the TCJA.

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the fiscal years ended September 30, 2018, 2017 and 2016:

Division	Jurisdiction	Rate Activity	Increase (Decrease) in Annual Operating Income	Effective Date
			(In thousands)	
2018 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad Valorem(1)	$ 457	02/01/2018
Total 2018 Other Rate Activity			$ 457	
2017 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad-Valorem(1)	$ 784	02/01/2017
Total 2017 Other Rate Activity			$ 784	
2016 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad-Valorem(1)	$ (183)	02/01/2016
Total 2016 Other Rate Activity			$ (183)	

(1) The Ad Valorem filing relates to property taxes that are either over or uncollected compared to the amount included in our Kansas service area's base rates.

Other Regulation

We are regulated by various state or local public utility authorities. We are also subject to regulation by the United States Department of Transportation with respect to safety requirements in the operation and maintenance of our transmission and distribution facilities. In addition, our operations are also subject to various state and federal laws regulating environmental matters. From time to time, we receive inquiries regarding various environmental matters. We believe that our properties and operations substantially comply with, and are operated in substantial conformity with, applicable safety and environmental statutes and regulations. There are no administrative or judicial proceedings arising under environmental quality statutes pending or known to be contemplated by governmental agencies which would have a material adverse effect on us or our operations. Our environmental claims have arisen primarily from former manufactured gas plant sites. The Pipeline and Hazardous Materials Safety Administration (PHMSA), within the U.S. Department of Transportation, develops and enforces regulations for the safe, reliable and environmentally sound operation of the pipeline transportation system. The PHMSA pipeline safety statutes provide for states to assume safety authority over intrastate and natural gas pipelines. State pipeline safety programs are responsible for adopting and enforcing the federal and state pipeline safety regulations for intrastate natural gas transmission and distribution pipelines.

The Federal Energy Regulatory Commission (FERC) allows, pursuant to Section 311 of the Natural Gas Policy Act (NGA), gas transportation services through our Atmos Pipeline—Texas assets "on behalf of" interstate pipelines or local distribution companies served by interstate pipelines, without subjecting these assets to the jurisdiction of the FERC under the NGA. Additionally, the FERC has regulatory authority over the use and release of interstate pipeline and storage capacity. The FERC also has authority to detect and prevent market manipulation and to enforce compliance with FERC's other rules, policies and orders by companies engaged in the sale, purchase, transportation or storage of natural gas in interstate commerce. We have taken what we believe are the necessary and appropriate steps to comply with these regulations.

The SEC and the Commodities Futures Trading Commission, pursuant to the Dodd–Frank Act, established numerous regulations relating to U.S. financial markets. We enacted procedures and modified existing business practices and contractual arrangements to comply with such regulations. There are, however, some rulemaking proceedings that have not yet been finalized, including those relating to capital and margin rules for (non–cleared) swaps. We do not expect these rules to directly impact our business practices or collateral requirements. However, depending on the substance of these final rules, in addition to certain international regulatory requirements still under development that are similar to Dodd–Frank, our swap counterparties could be subject to additional and potentially significant capitalization requirements. These regulations could motivate counterparties to increase our collateral requirements or cash postings.

Competition

Although our regulated distribution operations are not currently in significant direct competition with any other distributors of natural gas to residential and commercial customers within our service areas, we do compete with other natural gas suppliers and suppliers of alternative fuels for sales to industrial customers. We compete in all aspects of our business with

Case No. 2018-00281
Atmos Energy Corporation, Kentucky Division
Staff DR Set No. 3
Question No. 3-10

REQUEST:

Refer to Atmos's response to Staff's Second Request, Item 33.b. Provide the 13-month average capitalization for the forecasted test period.

RESPONSE:

Please see confidential Attachment 1.

ATTACHMENT:

ATTACHMENT 1 - Atmos Energy Corporation, Staff 3_10_Att1 - Capital Structure Mar'19-Mar'20 (CONFIDENTIAL).xlsx, 1 Page.

Respondent: Joe Christian

Case No. 2018-00281
Atmos Energy Corporation, Kentucky Division
Staff DR Set No. 3
Question No. 3-11
Page 1 of 1

REQUEST:

Refer to Atmos's response to Staff's Second Request, Item 34.a.

a. Provide the calculation of the estimated $63 million to be paid when settled.

b. Explain whether the $63 million will be incurred in connection to the settlement of the original note or the establishment of the refinanced note.

RESPONSE:

a. Please see Attachment 1.

b. The $63 million will be incurred in connection with the establishment of the refinanced note.

ATTACHMENT:

ATTACHMENT 1 - Atmos Energy Corporation Staff_3-11_att1 - Swaps Calculation.xlsx, 1 Page.

Respondent: Joe Christian

Case No. 2018-00281
Atmos Energy Corporation, Kentucky Division
Staff DR Set No. 4
Question No. 4-08 Supplement

(SUPPLEMENTAL RESPONSE 3/12/2019)

REQUEST:

Refer to Atmos's response to the Attorney General's Second Request, Item 10.b, Attachment 1.

a. Explain why Atmos entered into treasury locks four to five years before the effective date.

b. Provide the estimated date that the refinanced note will be issued.

c. Refer also to Atmos's response to Staff's First Request, Item 64, Attachment 1 , page 2.

(1) Confirm that the "Underlying Treasury Yield Component" is equal to the fixed treasury rate achieved through Atmos's hedging activity.

(2) State whether Atmos will issue the note at a premium to settle the treasury lock with the counterparties. If so, explain why Atmos included both the premium and the fixed treasury component in the calculation.

RESPONSE:

a. Please note that the Company entered into interest rate swaps in advance of the March 2019 debt maturity, not treasury locks.

As stated in the Company's response to AG DR No. 2-10 subpart (b), Attachment 1, when the Company entered into the forward starting interest rate swaps, the 30 year Treasury was near or at all time lows. Based on economic indicators and discussions with our bank partners, it was determined prudent at the time to enter into these financial instruments. As disclosed on page 36 of our Form 10-K filed with the SEC on November 13, 2017, “We manage interest rate risk by entering into financial instruments to effectively fix the Treasury yield component of the interest cost associated with anticipated financings."

The Company’s risk management objective and strategy with respect to this interest rate swap is to protect the Company (and consequently its customers) against adverse fluctuations in interest rates by reducing its exposure to variability in cash flows relating to interest payments on a forecasted issuance of debt. The Company met its objective by hedging the risk of changes in its cash flows (interest payments) attributable to changes in the 30-year USD-LIBOR-BBA swap rate, the designated benchmark interest rate being hedged.

b. The Company is evaluating current market conditions and a date has not been determined. Please see the response to subpart (c).

**Case No. 2018-00281
Atmos Energy Corporation, Kentucky Division
Staff DR Set No. 4
Question No. 4-08
Page 2 of 2**

c.

(1) Confirm.

(2) As originally contemplated, the Company expected to include the interest rate swaps in the principle of the new long-term debt. As the refinancing has approached we now believe that only the $450 million will be included in the new long-term debt issued to refinance the 2009 Sr. Note. The interest rate swaps will be paid out of general corporate funds. Please see Attachment 1 for a revised refinancing workpaper. The Company will update Schedule J-1 F and J-3 F at the time rebuttal is filed on March 13, 2019 to reflect the latest available refinancing information.

<u>SUPPLEMENTAL RESPONSE:</u>

c.

(2) As originally contemplated, the Company expected to include the interest rate swaps in the principle of the new long-term debt. As the refinancing approached the Company re-evaluated and determined that only the $450 million would be included in the new long-term debt issued to refinance the 2009 Sr. Note. The interest rate swaps where paid out of general corporate funds. Please see Rebuttal Testimony of Mr. Christian and Rebuttal Model (Schedule J-1 F and J-3 F) attached to the Rebuttal Testimony of Mr. Waller for the actual refinancing costs and their impact on the Company's deficiency.

Respondent: Joe Christian

Case No. 2018-00281
Atmos Energy Corporation, Kentucky Division
AG DR Set No. 1
Question No. 1-16
Page 1 of 1

REQUEST:

Refer to the Company's response to Staff 1-03, Schedule 3a, which provides the components of the capital structure for Atmos Energy Corporation for the prior calendar years from 2003 to 2017 using ending balances and daily average balances of short term debt. Identify and describe all reasons why the Company decreased the level of short term debt starting in 2017 and in the filing compared to the average balances portrayed in the data response for all years since 2012.

RESPONSE:

The Company currently anticipates incremental long-term financing of $5.0 billion - $6.0 billion through fiscal 2023. This incremental financing will be accomplished through the issuance of debt and equity securities to maintain a balanced capital structure with an equity-to-capitalization ratio in a target range of 50 to 60 percent, inclusive of short-term debt. Short-term debt will be utilized to provide cost-effective financing until it can be replaced with a mix of long-term debt and equity financing. This incremental financing will be supported by a $3 billion shelf registration statement filed in November 2018. The financing is expected to support our current credit metrics.

In order to accomplish our anticipated five year financing needs, the Company has improved its credit metrics through increased equity and decreased our reliance on debt financing, in order to access the capital markets on terms that will be more favorable than if we had not improved our credit metrics in recent years. The Company anticipates the continued need to invest in the safety and reliability of our gas distribution systems at levels that drive this level of incremental financing, thus supporting our current credit metrics is very important. The lowered reliance on short-term debt, as compared to levels shown in Staff DR No. 1-03, Schedule 3a, is driven by the more frequent need to access the long-term debt markets, which is driven by higher levels of capital investment ($5.5 billion between 2014 and 2018 vs. $9.0 - 10.0 billion in 2019-2023 time period).

Respondent: Joe Christian

Case No. 2018-00281
Atmos Energy Corporation, Kentucky Division
DR AG Set No. 1
Question No. 1-17
Page 1 of 1

REQUEST:

Refer to the Company's response to Staff 1-03, Schedule 3a, which provides the components of the capital structure for Atmos Energy Corporation for the prior calendar years from 2003 to 2017. Refer also to Schedule J-1 which shows the Total Company capitalization projections for the base year and the test year and that projects the common equity percentage as 58.24%. Finally refer to the Company's Schedule J-1 from Case No. 2017-00349 and the Commission's Order at page 30 from Case No. 2017-00349, both of which reflected common equity percentages of 52.57%.

a. Identify and describe all reasons for the increased percentage of common equity starting primarily in 2017 as compared to all prior years. For instance, is the actual and projected increase in common equity the primary result of projected decreases in the level of dividends or increases in the level of earnings or paid in capital?

b. Provide the current authorized ROEs and capital structures for all other regulated Atmos divisions and cite all authorities.

RESPONSE:

a. The increase in common equity percentage from Case No. 2017-00349 to this instant case is primarily driven by a $400 mm equity issuance in November 2017. Please see the Company's response to AG DR No. 1-16 for more information regarding anticipated incremental financing as well as the need to maintain strong credit metrics.

b. Please see the Company's response to Staff DR No. 2-59 for a list of current authorized ROEs. Please see the Company's FY 2018 10K, page 7 for the latest authorized capital structures for Atmos Energy's jurisdictions.

Respondent: Joe Christian

Case No. 2018-00281
Atmos Energy Corporation, Kentucky Division
AG DR Set No. 1
Question No. 1-20
Page 1 of 1

REQUEST:

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

RESPONSE:

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

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

Respondent: Joe Christian

Case No. 2018-00281
Atmos Energy Corporation, Kentucky Division
AG DR Set No. 1
Question No. 1-25
Page 1 of 1

REQUEST:

Confirm that although Atmos has six separate operating divisions, Mr. Christian states in his testimony at p. 6 that the appropriate capital structure for each operating division (including the Kentucky/Mid-States Division) "...is equivalent to the consolidated capital structure for Atmos Energy as a whole."

RESPONSE:

The full response to the question, "SHOULD ATMOS ENERGY'S CONSOLIDATED CAPITAL STRUCTURE BE USED AS THE BASIS FOR A CAPITAL STRUCTURE IN THIS PROCEEDING?" is "Yes. *Although* this proceeding only affects the rates which may be charged by the Company for its regulated utility operations in Kentucky, the appropriate capital structure for each of the Atmos Energy utility operating divisions, including its Kentucky/Mid-States Division, *is equivalent to the consolidated capital structure for Atmos Energy as a whole*. Atmos Energy's consolidated capital structure is appropriate for use in setting rates for the Company's Kentucky customers because Atmos Energy provides the debt and equity capital that supports the assets serving those customers."

Respondent: Joe Christian

Case No. 2018-00281
Atmos Energy Corporation, Kentucky Division
AG DR Set No. 1
Question No. 1-28
Page 1 of 1

REQUEST:

Provide the capital structure applicable solely to Atmos' Kentucky-based operations.

RESPONSE:

Please see the Direct Testimony of Mr. Joe Christian, page 5, line 15 continuing to page 6, line 7. As indicated in this section of testimony, there is no capital structure applicable solely to Atmos Energy's Kentucky-based operations.

Respondent: Joe Christian

Case No. 2018-00281
Atmos Energy Corporation, Kentucky Division
AG DR Set No. 2
Question No. 2-20

REQUEST:

Refer to the Company's 2018 10-K at page 58 which included the following notation concerning a new debt issue and the Direct Testimony of Mr. Christian at pages 5-8.

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

a. Was Mr. Christian aware of the referenced senior note public offering at the time the instant case including his testimony was filed? If the answer is yes, explain all reasons why this new debt issue was not discussed by Mr. Christian or reflected in the Company's filing.

b. Provide updated cost of capital Schedules J-1, J-2, and J-3 to reflect the effects of this new issue on the capital structure, cost of long-term debt, and cost of capital.

RESPONSE:

a. At the time of the senior note public offering Mr. Christian was aware of Atmos Energy's currently anticipated incremental long-term financing of $3.5 - $4.0 billion through fiscal 2022, including impact from the TCJA which is based on estimated cumulative capital spending of ~ $8 billion through fiscal 2022. Although Mr. Christian did not speak specifically to the offering he did suggest in his Direct Testimony page 8, lines 11-18 that the capital structure can be updated with more current information anticipating that some of the incremental long-term financing disclosed in investor presentations could occur prior to the end of 2018.

b. Please see the Company's response to Staff DR No. 3-10 for the monthly forecast capital structure for the test period ended March 2020. This includes the requested October financing, as included in the Company's financing plan, as well as other anticipated financing during the test period.

Respondent: Joe Christian

Atmos Energy
Case No. 2018-00281
Comparison of Debt Cost using Bloomberg Financial Services Bond Value Yields

Line #	Tenor	Example Amounts	Rating [1]	Rating [2]	Delta	Est. Expense Savings
	(a)	(b)	(c)	(d)	(e)	(f)
1	10 Y	960,000,000	3.719	4.086	0.367	3,523,200
2	30 Y	2,640,000,000	4.245	4.593	0.348	9,187,200
3		3,600,000,000				12,710,400
4						
5						

6 Source: Bloomberg rates for February 15, 2019
7 (1) US Utilities A+ A A- BVAL Yield for the 10Y and 30Y tenors.
8 (2) US Utilities BBB+ BBB BBB- BVAL Yield for the 10Y and 30Y tenors.
9
10 The BVAL curve is populated with USD denominated senior unsecured fixed rate bonds
11 issued by Utilities companies with the respective Bloomberg composite rating.

Filed Pursuant to Rule 424(b)(2)
Registration No. 333-228342

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to be Registered	Amount to be Registered	Maximum Offering Price Per Security	Maximum Aggregate Offering Price	Amount of Registration Fee (1)
4.125% Senior Notes due 2049	$450,000,000	99.606%	$448,227,000	$54,325.11

(1) Calculated in accordance with Rule 457(r) of the Securities Act of 1933.

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Prospectus Supplement
February 25, 2019
(To Prospectus dated November 13, 2018)

$450,000,000

Atmos Energy Corporation

4.125% Senior Notes due 2049

The 4.125% Senior Notes due 2049 (the "notes") will bear interest at the rate of 4.125% per year and will mature on March 15, 2049. We will pay interest on the notes semi-annually in arrears on March 15 and September 15 of each year they are outstanding, beginning September 15, 2019. We may redeem the notes prior to maturity at our option, at any time in whole or from time to time in part, at the applicable redemption price described in this prospectus supplement. See "Description of the Notes—Optional Redemption."

The notes are unsecured and rank equally with all of our other existing and future unsubordinated debt. The notes will be issued only in registered form in minimum denominations of $2,000 and any integral multiple of $1,000 in excess thereof. The notes are a new issue of securities with no established trading market. The notes will not be listed on any securities exchange or on any automated dealer quotation system.

Investing in the notes involves risks. See " Risk Factors " on page S-9 of this prospectus supplement.

	Public Offering Price (1)	Underwriting Discount	Proceeds, Before Expenses, to Atmos Energy
Per note	99.606%	0.875%	98.731%
Total	$ 448,227,000	$ 3,937,500	$ 444,289,500

(1) Plus accrued interest from March 4, 2019, if settlement occurs after that date.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus supplement or the accompanying prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the notes to investors in book-entry form only through the facilities of The Depository Trust Company for the accounts of its participants, including Clearstream Banking S.A. and/or Euroclear Bank S.A./N.V., on or about March 4, 2019.

Joint Book-Running Managers

BNP PARIBAS **CIBC Capital Markets** **Credit Agricole CIB** **Wells Fargo Securities**
Mizuho Securities **MUFG** **TD Securities**

Senior Co-Manager

Regions Securities LLC

Co-Managers

BB&T Capital Markets **The Williams Capital Group, L.P.**

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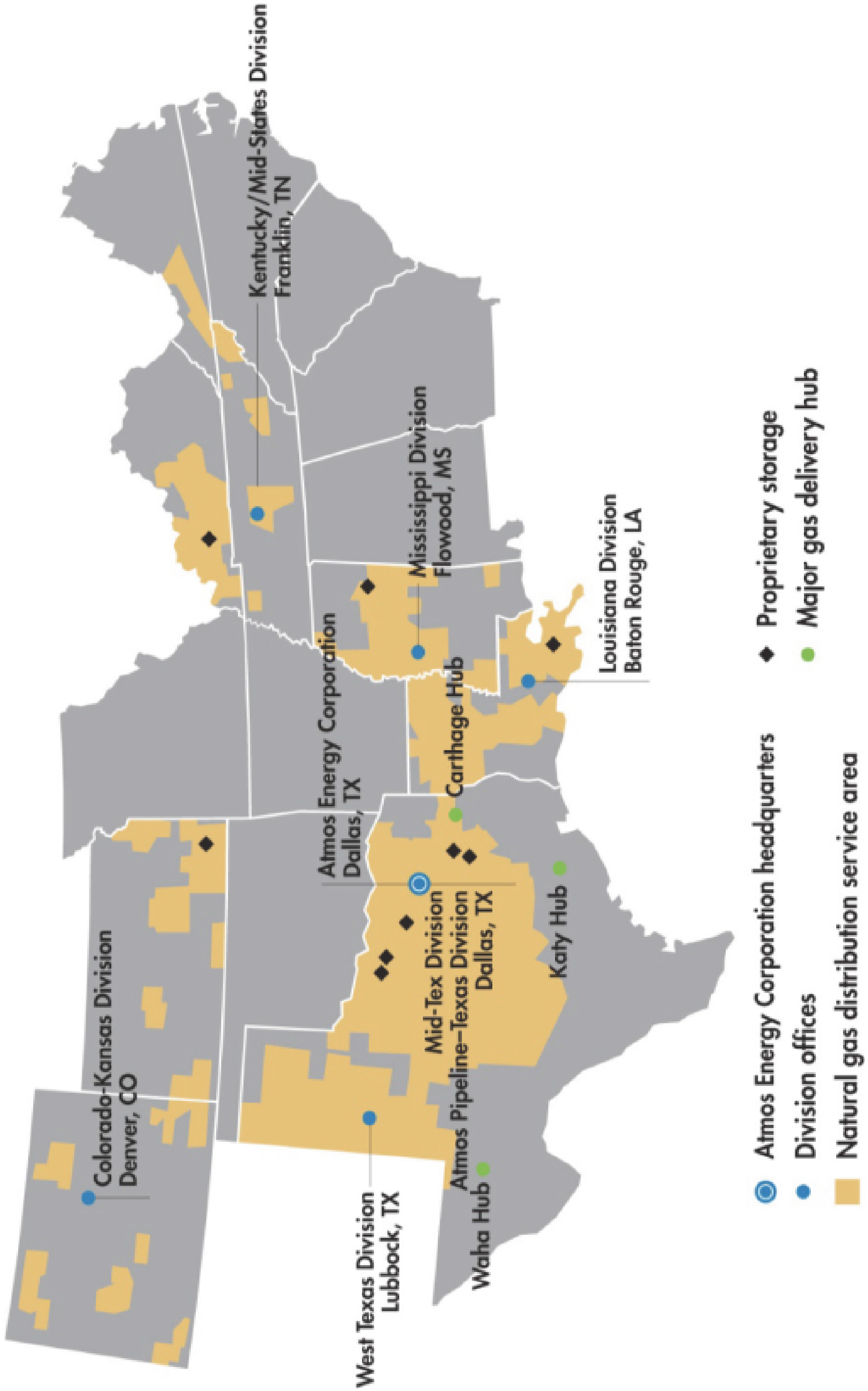

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Prospectus Supplement

Prospectus

IMPORTANT NOTICE ABOUT INFORMATION IN THIS PROSPECTUS SUPPLEMENT AND THE ACCOMPANYING PROSPECTUS

This document consists of two parts. The first part is this prospectus supplement, which describes the specific terms of this offering of the notes and also adds to and updates information contained in the accompanying prospectus and the documents incorporated by reference in this prospectus supplement and the accompanying prospectus. The second part is the accompanying prospectus, dated November 13, 2018, which gives more general information, some of which does not apply to this offering. To the extent there is a conflict between the information contained in this prospectus supplement, the information contained in the accompanying prospectus or the information contained in any document incorporated by reference herein or therein, the information contained in the most recent document shall control. This prospectus supplement and the accompanying prospectus are a part of a registration statement that we filed with the Securities and Exchange Commission (the "SEC") using the SEC's shelf registration rules.

We have not, and the underwriters have not, authorized any other person to provide you with information other than information provided or incorporated by reference in this prospectus supplement, the accompanying prospectus or any free writing prospectus relating to the offering of notes made pursuant to this prospectus supplement. We and the underwriters take no responsibility for, and can provide no assurances as to the reliability of, any other information that others may give you or representations that others may make. See "Incorporation of Certain Documents by Reference" and "Where You Can Find More Information" in the accompanying prospectus.

Neither Atmos Energy Corporation nor the underwriters are making an offer of these notes in any jurisdiction where the offer is not permitted.

The information contained in or incorporated by reference in this document is accurate only as of the date of this prospectus supplement or the date of such incorporated documents, regardless of the time of delivery of this prospectus supplement or of any sale of notes. Our business, financial condition, results of operations and prospects may have changed since those respective dates.

The terms "we," "our," "us," and "Atmos Energy" refer to Atmos Energy Corporation and its subsidiaries unless the context suggests otherwise. The term the "Company" refers to Atmos Energy Corporation and not its subsidiaries. The term "you" refers to a prospective investor. The abbreviations "Mcf" and "MMBtu" mean thousand cubic feet and million British thermal units, respectively.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Statements contained or incorporated by reference in this prospectus supplement and the accompanying prospectus that are not statements of historical fact are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended. Forward-looking statements are based on management's beliefs as well as assumptions made by, and information currently available to, management. Because such statements are based on expectations as to future results and are not statements of fact, actual results may differ materially from those stated. Important factors that could cause future results to differ include, but are not limited to:

- state and local regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions;
- increased federal regulatory oversight and potential penalties;
- possible increased federal, state and local regulation of the safety of our operations;
- the inherent hazards and risks involved in distributing, transporting and storing natural gas;
- the capital-intensive nature of our business;
- our ability to continue to access the credit and capital markets to execute our business strategy;
- market risks beyond our control affecting our risk management activities, including commodity price volatility, counterparty performance or creditworthiness and interest rate risk;
- the concentration of our operations in Texas;
- the impact of adverse economic conditions on our customers;
- changes in the availability and price of natural gas;
- the availability and accessibility of contracted gas supplies, interstate pipeline and/or storage services;
- increased competition from energy suppliers and alternative forms of energy;
- adverse weather conditions;
- increased costs of providing health care benefits, along with pension and postretirement health care benefits and increased funding requirements;
- the inability to continue to hire, train and retain operational, technical and managerial personnel;
- the impact of climate change or related additional legislation or regulation in the future;
- the threat of cyber-attacks or acts of cyber-terrorism that could disrupt our business operations and information technology systems or result in the loss or exposure of confidential or sensitive customer, employee or Company information;
- natural disasters, terrorist activities or other events; and
- other risks and uncertainties discussed in this prospectus supplement, any accompanying prospectus and our other filings with the SEC.

All of these factors are difficult to predict and many are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. When used in our documents or oral presentations, the words "anticipate," "believe," "estimate," "expect," "forecast," "goal," "intend," "objective," "plan," "projection," "seek," "strategy" or similar words are intended to identify forward-looking statements. We undertake no obligation to update or revise any of our forward-looking statements, whether as a result of new information, future events or otherwise.

For additional factors you should consider, please see “Risk Factors” on page S-9 of this prospectus supplement, “Item 1A. Risk Factors” and “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” in our Annual Report on Form 10-K for the fiscal year ended September 30, 2018 and “Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations” in our Quarterly Report on Form 10-Q for the quarterly period ended December 31, 2018. See also “Incorporation of Certain Documents by Reference” in the accompanying prospectus.

PROSPECTUS SUPPLEMENT SUMMARY

You should read the following summary in conjunction with the more detailed information contained elsewhere in this prospectus supplement, the accompanying prospectus and the documents incorporated by reference in this prospectus supplement and the accompanying prospectus.

ATMOS ENERGY CORPORATION

Atmos Energy Corporation, headquartered in Dallas, Texas, and incorporated in Texas and Virginia, is one of the country's largest natural-gas-only distributors based on number of customers. We deliver natural gas through regulated sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers in eight states located primarily in the South. We also operate one of the largest intrastate pipelines in Texas based on miles of pipe.

We manage and review our consolidated operations through the following two segments:

- The *distribution segment* is primarily comprised of our regulated natural gas distribution and related sales operations in eight states.
- The *pipeline and storage segment* is comprised primarily of the pipeline and storage operations of our Atmos Pipeline—Texas division and our natural gas transmission operations in Louisiana.

Recent Developments

Declaration of Dividend . On February 5, 2019, our Board of Directors declared a quarterly dividend on our common stock of $0.525 per share. The dividend will be paid on March 11, 2019, to shareholders of record on February 25, 2019.

Our address is 1800 Three Lincoln Centre, 5430 LBJ Freeway, Dallas, Texas 75240, and our telephone number is (972) 934-9227. Our internet website address is *www.atmosenergy.com.* Information on or connected to our website or any other website is not incorporated by reference into this prospectus supplement or the accompanying prospectus.

SUMMARY FINANCIAL DATA

The following table presents summary consolidated and segment financial data of Atmos Energy Corporation for the periods and as of the dates indicated. We derived the summary financial data for the fiscal years ended September 30, 2018, 2017, 2016, 2015 and 2014 from our audited consolidated financial statements and the summary financial data for the three months ended December 31, 2018 and 2017 from our unaudited condensed consolidated financial statements. Our unaudited condensed consolidated financial statements have been prepared on the same basis as our audited consolidated financial statements, except as stated in the related notes thereto and, in the opinion of management, include all normal recurring adjustments considered necessary for a fair presentation of our financial condition and result of operations for such periods. Please note that, given the inherent seasonality in our business, the results of operations for the three months ended December 31, 2018 presented below are not necessarily indicative of results for the entire fiscal year.

The information is only a summary and does not provide all of the information contained in our financial statements. Therefore, you should read the information presented below in conjunction with “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and our consolidated financial statements and related notes included in our annual report on Form 10-K for the fiscal year ended September 30, 2018 and “Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and our unaudited condensed consolidated financial statements and related notes included in our quarterly report on Form 10-Q for the quarterly period ended December 31, 2018, each of which is incorporated by reference in this prospectus supplement and the accompanying prospectus.

	Three Months Ended December 31,		Year Ended September 30,				
	2018	2017	2018	2017	2016	2015	2014
	(unaudited)		(In thousands, except per share data)				
Consolidated Financial Data							
Operating revenues	$ 877,782	$ 889,192	$ 3,115,546	$ 2,759,735	$ 2,454,648	$ 2,926,985	$ 3,243,904
Purchased gas cost	$ 342,165	$ 366,917	$ 1,167,848	$ 925,536	$ 746,192	$ 1,295,675	$ 1,722,060
Operating expenses	$ 299,153	$ 280,192	$ 1,224,564	$ 1,106,653	$ 1,051,226	$ 1,019,078	$ 944,622
Operating income	$ 236,464	$ 242,083	$ 723,134	$ 727,546	$ 657,230	$ 612,232	$ 577,222
Income from continuing operations	$ 157,646	$ 314,132	$ 603,064	$ 382,711	$ 345,542	$ 305,623	$ 270,331
Income from discontinued operations(1)(3)	—	—	—	$ 13,710	$ 4,562	$ 9,452	$ 19,486
Net income(4)	$ 157,646	$ 314,132	$ 603,064	$ 396,421	$ 350,104	$ 315,075	$ 289,817
Diluted net income per share from continuing operations(4)	$ 1.38	$ 2.89	$ 5.43	$ 3.60	$ 3.33	$ 3.00	$ 2.76
Diluted net income per share	$ 1.38	$ 2.89	$ 5.43	$ 3.73	$ 3.38	$ 3.09	$ 2.96
Cash dividends declared per share(4)	$ 0.525	$ 0.485	$ 1.94	$ 1.80	$ 1.68	$ 1.56	$ 1.48
Cash flows from operating activities	$ 164,684	$ 173,238	$ 1,124,662	$ 867,090	$ 794,990	$ 811,914	$ 732,813
Capital expenditures	$ 416,404	$ 383,238	$ 1,467,591	$ 1,137,089	$ 1,086,950	$ 963,621	$ 824,441

See footnotes on following page.

	As of December 31,		As of September 30,				
	2018	2017	2018	2017	2016	2015	2014
	(unaudited)		(In thousands)				
Total Assets	$12,615,789	$11,264,720	$11,874,437	$10,749,596	$10,010,889	$9,075,072	$8,581,006
Debt							
Long-term debt(2)	$ 3,084,779	$ 3,067,469	$ 2,493,665	$ 3,067,045	$ 2,188,779	$2,437,515	$2,442,288
Short-term debt(2)	$ 575,000	$ 336,816	$ 1,150,780	$ 447,745	$ 1,079,811	$ 457,927	$ 196,695
Total debt	$ 3,659,779	$ 3,404,285	$ 3,644,445	$ 3,514,790	$ 3,268,590	$2,895,442	$2,638,983
Shareholder's equity	$ 5,348,195	$ 4,563,620	$ 4,769,951	$ 3,898,666	$ 3,463,059	$3,194,797	$3,086,232

	Three Months Ended December 31,		Year Ended September 30,				
Segment Operating Income(3)	2018	2017	2018	2017	2016	2015	2014
	(unaudited)		(In thousands)				
Distribution	$ 169,437	$ 173,278	$480,867	$505,642	$441,884	$422,692	$388,617
Pipeline and storage	$ 67,027	$ 68,805	$242,267	$221,904	$215,346	$189,540	$188,605
Eliminations	—	—	—	—	—	—	—
Consolidated	$ 236,464	$ 242,083	$723,134	$727,546	$657,230	$612,232	$577,222

(1) Income from discontinued operations for the fiscal year ended September 30, 2017 includes a gain on the sale of discontinued operations of $2.7 million.
(2) Long-term debt excludes current maturities. Short-term debt is comprised of current maturities of long-term debt and short-term debt.
(3) We manage and review our consolidated operations through the following two reportable segments: (i) Distribution and (ii) Pipeline and Storage. The financial results of our former Natural Gas Marketing segment are reported as discontinued operations for all periods presented.
(4) In fiscal 2018, the enactment of the Tax Cuts and Jobs Act of 2017 required us to remeasure our deferred tax assets and liabilities at our new federal statutory income tax rate as of December 22, 2017. This remeasurement resulted in the recognition of a non-cash income tax benefit of $161.9 million, or $1.49 per diluted share, for the three months ended December 31, 2017 and $158.8 million, or $1.43 per diluted share, for the fiscal year ended September 30, 2018.

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THE OFFERING

Issuer	Atmos Energy Corporation
Notes Offered	$450,000,000 aggregate principal amount of 4.125% senior notes due 2049.
Maturity	The notes will mature on March 15, 2049.
Interest	The notes will bear interest at the rate of 4.125% per year.
	Interest on the notes will be payable semi-annually in arrears on March 15 and September 15 of each year they are outstanding, beginning on September 15, 2019, and will be payable to holders of record at the close of business on the March 1 or September 1 immediately preceding the interest payment date (whether or not a business day).
Ranking	The notes will be our unsecured senior obligations. The notes will rank equally in right of payment with all our existing and future unsubordinated indebtedness and will rank senior in right of payment to any future indebtedness that is subordinated to the notes. The notes will be effectively subordinated to all our existing and future secured indebtedness to the extent of the assets securing such indebtedness and to the indebtedness and liabilities of our subsidiaries.
Optional Redemption	We may redeem the notes at any time in whole, or from time to time in part, prior to September 15, 2048, at the “make-whole” redemption price described in this prospectus supplement. We also have the option at any time on or after September 15, 2048 (which is the date that is six months prior to the maturity date of the notes) to redeem the notes, in whole or in part, at a redemption price equal to 100% of the principal amount of the notes to be redeemed, plus, in each case, accrued and unpaid interest, if any, to the redemption date as described in “Description of the Notes—Optional Redemption,” beginning on page S-16.
Covenants of the Indenture	We will issue the notes under an indenture, which will, among other things, restrict our ability to create liens and to enter into sale and leaseback transactions. See “Description of Debt Securities—Covenants” beginning on page 9 of the accompanying prospectus.
Use of Proceeds	We estimate that our net proceeds from this offering, after deducting the underwriting

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	discount and estimated offering expenses payable by us, will be approximately $443 million. We intend to use the net proceeds from this offering, together with available cash, to repay at maturity our $450 million aggregate principal amount of 8.50% Senior Unsecured Notes due March 15, 2019. See “Use of Proceeds” on page S-9.
Trustee	U.S. Bank National Association
Risk Factors	Investing in the notes involves risks. See “Risk Factors” on page S-9 of this prospectus supplement and other information included and incorporated by reference in this prospectus supplement and the accompanying prospectus for a discussion of the factors you should consider carefully before deciding to invest in the notes.

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RISK FACTORS

Investing in the notes involves risks. Our business is influenced by many factors that are difficult to predict and beyond our control and that involve uncertainties that may materially affect our results of operations, financial condition or cash flows, or the value of the notes. These risks and uncertainties include those described in the risk factors and other sections of the documents that are incorporated by reference in this prospectus supplement and the accompanying prospectus, including "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the fiscal year ended September 30, 2018. You should carefully consider these risks and uncertainties and all of the information contained or incorporated by reference in this prospectus supplement and the accompanying prospectus before you invest in the notes.

USE OF PROCEEDS

We estimate that we will receive net proceeds from this offering of approximately $443 million, after deducting the underwriting discount and estimated offering expenses payable by us. We intend to use the net proceeds from this offering, together with available cash, to repay at maturity our $450 million aggregate principal amount of 8.50% Senior Unsecured Notes due March 15, 2019.

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CAPITALIZATION

The following table presents our cash and cash equivalents, short-term debt and capitalization as of December 31, 2018, on an actual basis and as adjusted to reflect the issuance of notes in this offering and the use of proceeds therefrom as described under "Use of Proceeds" and the settlement of certain forward starting interest rate swaps that we entered into during fiscal 2014 and 2015 to fix the Treasury yield component of the interest cost associated with a notional principal amount of $450 million in anticipated notes and for which we expect to pay approximately $90 million upon settlement. You should read this table in conjunction with the section entitled "Use of Proceeds" and our condensed consolidated financial statements and related notes included in our Quarterly Report on Form 10-Q for the quarterly period ended December 31, 2018, which is incorporated by reference in this prospectus supplement.

	As of December 31, 2018	
	Actual	As Adjusted
	(unaudited) (In thousands, except share data)	
Cash and cash equivalents	$ 218,197	$ 121,345
Short-term debt		
Current maturities of long-term debt	$ 575,000	$ 125,000
Other short-term debt	—	—
Total short-term debt	$ 575,000	$ 125,000
Long-term debt, less current portion	$ 3,084,779	$ 3,528,069
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; 116,892,959 shares issued and outstanding, actual and as adjusted	584	584
Additional paid-in capital	3,476,476	3,476,476
Retained earnings	1,985,250	1,985,250
Accumulated other comprehensive loss	(114,115)	(117,366)
Shareholders' equity	5,348,195	5,344,944
Total capitalization(1)	$ 8,432,974	$ 8,873,013

(1) Total capitalization excludes the current portion of long-term debt and other short-term debt.

BUSINESS

Overview

Atmos Energy Corporation, headquartered in Dallas, Texas, and incorporated in Texas and Virginia, is one of the country's largest natural-gas-only distributors based on number of customers. We deliver natural gas through regulated sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers in eight states located primarily in the South. We also operate one of the largest intrastate pipelines in Texas based on miles of pipe.

Operating Segments

We manage and review our consolidated operations through the following two segments:

- The *distribution segment* is primarily comprised of our regulated natural gas distribution and related sales operations in eight states.
- The *pipeline and storage segment* is comprised primarily of the pipeline and storage operations of our Atmos Pipeline—Texas division ("APT") and our natural gas transmission operations in Louisiana.

Distribution Segment Overview

Our distribution segment is primarily comprised of our regulated natural gas distribution and related sales operations in eight states. The following table summarizes key information about our six regulated natural gas distribution divisions, presented in order of total rate base.

Division	Service Areas	Communities Served	Customer Meters
Mid-Tex	Texas, including the Dallas/Fort Worth Metroplex	550	1,697,171
Kentucky/Mid-States	Kentucky	230	182,510
	Tennessee		150,661
	Virginia		24,396
Louisiana	Louisiana	270	362,233
West Texas	Amarillo, Lubbock, Midland	80	313,828
Mississippi	Mississippi	110	269,333
Colorado-Kansas	Colorado	170	120,384
	Kansas		135,820

We operate in our service areas under terms of non-exclusive franchise agreements granted by the various cities and towns that we serve. At September 30, 2018, we held 1,013 franchises having terms generally ranging from five to 35 years. A significant number of our franchises expire each year, which require renewal prior to the end of their terms. Historically, we have successfully renewed these franchises and believe that we will continue to be able to renew our franchises as they expire.

Revenues in this operating segment are established by regulatory authorities in the states in which we operate. These rates are intended to be sufficient to cover the costs of conducting business, including a reasonable return on invested capital. In addition, we transport natural gas for others through our distribution systems.

Rates established by regulatory authorities often include cost adjustment mechanisms for costs that (i) are subject to significant price fluctuations compared to our other costs, (ii) represent a large component of our cost of service and (iii) are generally outside our control.

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Purchased gas cost adjustment mechanisms represent a common form of cost adjustment mechanism. Purchased gas cost adjustment mechanisms provide natural gas distribution companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case because they provide a dollar-for-dollar offset to increases or decreases in the cost of natural gas. Therefore, although substantially all of our natural gas distribution operating revenues fluctuate with the cost of gas that we purchase, distribution Contribution Margin (a Non-GAAP measure defined as operating revenues less purchased gas cost) is generally not affected by fluctuations in the cost of gas.

Additionally, some jurisdictions have performance-based ratemaking adjustments to provide incentives to distribution companies to minimize purchased gas costs through improved storage management and use of financial instruments to lock in gas costs. Under the performance-based ratemaking adjustment, purchased gas costs savings are shared between the utility and its customers.

Our rate strategy focuses on reducing or eliminating regulatory lag, obtaining adequate returns and providing stable, predictable margins, which benefit both our customers and the Company. As a result of our ratemaking efforts in recent years, Atmos Energy has:

- Formula rate mechanisms in place in four states that provide for an annual rate review and adjustment to rates.
- Infrastructure programs in place in the majority of our states that provide for an annual adjustment to rates for qualifying capital expenditures. Through our annual formula rate mechanisms and infrastructure programs, we have the ability to recover over 85 percent of our capital expenditures within six months and 99 percent within twelve months.
- Authorization in tariffs, statute or commission rules that allows us to defer certain elements of our cost of service such as depreciation, ad valorem taxes and pension costs, until they are included in rates.
- Weather normalization adjustment mechanisms in seven states that serve to minimize the effects of weather on approximately 97 percent of our Contribution Margin.
- The ability to recover the gas cost portion of bad debts in five states.

Pipeline and Storage Segment Overview

Our pipeline and storage segment consists of the pipeline and storage operations of APT and our natural gas transmission operations in Louisiana. APT is one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas-producing areas of central, northern and eastern Texas, extending into or near the major producing areas of the Barnett Shale, the Texas Gulf Coast and the Delaware and Val Verde Basins of West Texas. APT provides transportation and storage services to our Mid-Tex Division, other third party local distribution companies, industrial and electric generation customers, marketers and producers. As part of its pipeline operations, APT owns and operates five underground storage reservoirs in Texas.

Revenues earned from transportation and storage services for APT are subject to traditional ratemaking governed by the Railroad Commission of Texas. Rates are updated through periodic filings made under Texas’ Gas Reliability Infrastructure Program (“GRIP”). GRIP allows us to include in our rate base annually approved capital costs incurred in the prior calendar year provided that we file a complete rate case at least once every five years. APT’s existing regulatory mechanisms allow certain transportation and storage services to be provided under market-based rates.

Our natural gas transmission operations in Louisiana are comprised of a 21-mile pipeline located in New Orleans, Louisiana that is primarily used to aggregate gas supply for our distribution division in

Louisiana under a long-term contract and on a more limited basis, to third parties. The demand fee charged to our Louisiana distribution division for these services is subject to regulatory approval by the Louisiana Public Service Commission. We also manage two asset management plans in Louisiana with distribution affiliates of the Company, which have been approved by applicable state regulatory commissions. Generally, these asset management plans require us to share with our distribution customers a significant portion of the cost savings earned from these arrangements.

Other Regulation

We are regulated by various state or local public utility authorities. We are also subject to regulation by the United States Department of Transportation with respect to safety requirements in the operation and maintenance of our transmission and distribution facilities. In addition, our operations are also subject to various state and federal laws regulating environmental matters. From time to time we receive inquiries regarding various environmental matters. We believe that our properties and operations substantially comply with, and are operated in substantial conformity with, applicable safety and environmental statutes and regulations. There are no administrative or judicial proceedings arising under environmental quality statutes pending or known to be contemplated by governmental agencies which would have a material adverse effect on us or our operations. Our environmental claims have arisen primarily from former manufactured gas plant sites. The Pipeline and Hazardous Materials Safety Administration ("PHMSA"), within the U.S. Department of Transportation, develops and enforces the regulations for the safe, reliable and environmentally sound operation of the pipeline transportation system. The PHMSA pipeline safety statutes provide for states to assume safety authority over intrastate and natural gas pipelines. State pipeline safety programs are responsible for adopting and enforcing the federal and state pipeline safety regulations for intrastate natural gas transmission and distribution pipelines.

The Federal Energy Regulatory Commission ("FERC") allows, pursuant to Section 311 of the Natural Gas Policy Act, gas transportation services through our Atmos Pipeline—Texas assets "on behalf of" interstate pipelines or local distribution companies served by interstate pipelines, without subjecting these assets to the jurisdiction of the FERC. Additionally, the FERC has regulatory authority over the sale of natural gas in the wholesale gas market and the use and release of interstate pipeline and storage capacity. The FERC also has authority to detect and prevent market manipulation and to enforce compliance with FERC's other rules, policies and orders by companies engaged in the sale, purchase, transportation or storage of natural gas in interstate commerce. We have taken what we believe are the necessary and appropriate steps to comply with these regulations.

Competition

Although our distribution operations are not currently in significant direct competition with any other distributors of natural gas to residential and commercial customers within our service areas, we do compete with other natural gas suppliers and suppliers of alternative fuels for sales to industrial customers. We compete in all aspects of our business with alternative energy sources, including, in particular, electricity. Electric utilities offer electricity as a rival energy source and compete for the space heating, water heating and cooking markets. Promotional incentives, improved equipment efficiencies and promotional rates all contribute to the acceptability of electrical equipment. The principal means to compete against alternative fuels is lower prices, and natural gas historically has maintained its price advantage in the residential, commercial and industrial markets.

Our pipeline and storage operations historically faced competition from other existing intrastate pipelines seeking to provide or arrange transportation, storage and other services for customers. In the last few years, several new pipelines have been completed, which has increased the level of competition in this segment of our business.

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Distribution, Transmission and Related Assets

At September 30, 2018, in our distribution segment, we owned an aggregate of 70,071 miles of underground distribution and transmission mains throughout our distribution systems. These mains are located on easements or rights-of-way. We maintain our mains through a program of continuous inspection and repair and believe that our system of mains is in good condition. Through our pipeline and storage segment we owned 5,678 miles of gas transmission lines as well.

Storage Assets

We own underground gas storage facilities in several states to supplement the supply of natural gas in periods of peak demand. At September 30, 2018, the underground gas storage facilities of our distribution segment had a total usable capacity of 13,103,562 Mcf and a maximum daily delivery capacity of 234,100 Mcf, with the underground gas storage facilities of our pipeline and storage segment having a total usable capacity of 46,494,589 Mcf and a maximum daily delivery capacity of 1,766,000 Mcf.

Additionally, we contract for storage service in underground storage facilities on many of the interstate pipelines serving us to supplement our proprietary storage capacity. The amount of our contracted storage capacity can vary from time to time. At September 30, 2018, we had contracted storage capacity as follows: (i) distribution segment—maximum quantity of 32,425,245 MMBtu and a maximum daily withdrawal quantity of 1,088,167 MMBtu and (ii) pipeline and storage segment—maximum storage quantity of 1,000,000 MMBtu and a maximum daily withdrawal quantity of 47,500 MMBtu.

For more information on our storage assets, see “Item 2. Properties” in our Annual Report on Form 10-K for the fiscal year ended September 30, 2018.

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DESCRIPTION OF THE NOTES

We have summarized certain provisions of the notes below. The notes constitute a series of the debt securities described in the accompanying prospectus. The notes will be issued under an indenture dated March 26, 2009 (the “indenture”) entered into with U.S. Bank National Association, as trustee.

The following description of certain terms of the notes and certain provisions of the indenture in this prospectus supplement supplements the description under “Description of Debt Securities” in the accompanying prospectus and, to the extent it is inconsistent with that description, replaces the description in the accompanying prospectus. This description is only a summary of the material terms and does not purport to be complete. We urge you to read the indenture, which we have filed with the SEC, because it, and not the description below and in the accompanying prospectus, will define your rights as a holder of the notes. We have filed the indenture as an exhibit to our current report on Form 8-K that was filed with the SEC on March 26, 2009. You may obtain a copy of the indenture from us without charge. See “Where You Can Find More Information” in the accompanying prospectus.

General

The notes initially will be limited to $450 million aggregate principal amount. We may, at any time, without the consent of the holders of the notes, issue additional notes having the same ranking, interest rate, maturity and other terms (except for the issue date, public offering price and, if applicable, the first interest payment date) as the notes. Any such additional notes, together with the notes being offered by this prospectus supplement, will constitute a single series of notes under the indenture.

The notes will be unsecured and unsubordinated obligations of Atmos Energy. Any secured debt that we may have from time to time will have a prior claim with respect to the assets securing that debt. As of December 31, 2018, we had no secured debt outstanding. The notes will rank equally with all of our other existing and future unsubordinated debt but will be effectively subordinated to the indebtedness and liabilities of our subsidiaries. The notes are not guaranteed by, and are not the obligation of, any of our subsidiaries. The notes will not be listed on any securities exchange or included in any automated quotation system.

The notes will be issued in book-entry form as one or more global notes registered in the name of the nominee of The Depository Trust Company, or DTC, which will act as a depository, in minimum denominations of $2,000 and any integral multiple of $1,000 in excess thereof. Beneficial interests in book-entry notes will be shown on, and transfers of the notes will be made only through, records maintained by DTC and its participants.

Payment of Principal and Interest

The notes will mature on March 15, 2049 and bear interest at the rate of 4.125% per year.

We will pay interest on the notes semi-annually in arrears on March 15 and September 15 of each year they are outstanding, beginning September 15, 2019.

Interest will accrue from March 4, 2019 or from the most recent interest payment date to which we have paid or provided for the payment of interest to the next interest payment date or the scheduled maturity date, as the case may be. We will pay interest computed on the basis of a 360-day year of twelve 30-day months.

We will pay interest on the notes in immediately available funds to the persons in whose names such notes are registered at the close of business on the March 1 and September 1 immediately preceding the applicable interest payment date.

Optional Redemption

The notes offered hereby will be redeemable prior to maturity, in whole or from time to time in part. Prior to September 15, 2048 (which is the date that is six months prior to the maturity date of the notes), the redemption price will be equal to the greater of:

- 100% of the principal amount of the notes to be redeemed; and
- as determined by the Quotation Agent (defined below), the sum of the present values of the Remaining Scheduled Payments (defined below) of principal and interest on the notes to be redeemed that would be due if the notes matured on the Par Call Date, discounted to the redemption date on a semi-annual basis assuming a 360-day year consisting of twelve 30-day months at the Adjusted Treasury Rate (defined below) plus 20 basis points;

plus, in each case, accrued and unpaid interest on the principal amount of the notes to be redeemed to the redemption date.

At any time on or after September 15, 2048 (which is the date that is six months prior to the maturity date of the notes), the redemption price will be equal to 100% of the principal amount of the notes to be redeemed, plus accrued and unpaid interest thereon to the redemption date.

Definitions. Following are definitions of the terms used in the optional redemption provisions discussed above.

"Adjusted Treasury Rate" means, for any redemption date, the rate per annum equal to the semi-annual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price of the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for that redemption date.

"Comparable Treasury Issue" means the United States Treasury security selected by the Quotation Agent as having a maturity comparable to the remaining term of the notes to be redeemed (assuming the notes matured on the Par Call Date) that would be used, at the time of a selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of the notes to be redeemed.

"Comparable Treasury Price" means, for any redemption date, the average of the Reference Treasury Dealer Quotations for that redemption date.

" *Par Call Date* " means September 15, 2048, which is the date that is six months prior to the maturity date of the notes.

"Quotation Agent" means any Reference Treasury Dealer appointed by us to act as a quotation agent.

" *Reference Treasury Dealer* " means each of BNP Paribas Securities Corp. and Wells Fargo Securities, LLC, and any Primary Treasury Dealer (as defined below) selected by CIBC World Markets Corp. and Credit Agricole Securities (USA) Inc. or any of such parties' successors; provided, however, that if any of the foregoing shall cease to be a primary U.S. Government securities dealer (each, a "Primary Treasury Dealer"), we will substitute therefor another nationally recognized investment banking firm that is a Primary Treasury Dealer.

"Reference Treasury Dealer Quotation" means, with respect to each Reference Treasury Dealer and any redemption date, the average, as determined by the trustee, of the bid and asked prices for the Comparable Treasury Issue (expressed, in each case, as a percentage of its principal amount) quoted in writing to the trustee at 5:00 p.m., Eastern time, by such Reference Treasury Dealer on the third business day preceding such redemption date.

"Remaining Scheduled Payments" means, with respect to each note to be redeemed, the remaining scheduled payments of the principal and interest on such note that would be due after the related redemption date but for such redemption; provided, however, that if such redemption date is not an interest payment date, the amount of the next succeeding scheduled interest payment on such note will be reduced by the amount of interest accrued on such note to such redemption date.

In the case of a partial redemption of the notes, the notes to be redeemed shall be selected by the trustee in accordance with the procedures of DTC from the outstanding notes not previously called for redemption. Notice of any redemption will be mailed by first class mail at least 30 days but not more than 60 days before the redemption date to each holder of the notes to be redeemed at its registered address. If any notes are to be redeemed in part only, the notice of redemption will state the portion of the principal amount of notes to be redeemed. A partial redemption will not reduce the portion of any note not being redeemed to a principal amount of less than $2,000. Unless we default in payment of the redemption price, on and after the redemption date, interest will cease to accrue on the notes or the portions of the notes called for redemption.

No Mandatory Redemption

We will not be required to redeem the notes before maturity.

No Sinking Fund

We will not be required to make any sinking fund payments with regard to the notes.

Restricted Subsidiaries

As of the date of this prospectus supplement, none of our subsidiaries would be considered a Restricted Subsidiary under the terms of the indenture.

Reports

We will:

(1) file with the trustee, within 30 days after we have filed the same with the SEC, unless such reports are available on the SEC's EDGAR filing system (or any successor thereto), copies of the annual reports and of the information, documents and other reports (or copies of such portions of any of the foregoing as the SEC may from time to time by rules and regulations prescribe), which we may be required to file with the SEC pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934, as amended; or, if we are not required to file information, documents or reports pursuant to either of such Sections, then we shall file with the trustee and the SEC, in accordance with rules and regulations prescribed from time to time by the SEC, such of the supplementary and periodic information, documents and reports which may be required pursuant to Section 13 of the Securities Exchange Act of 1934, as amended, in respect of a security listed and registered on a national securities exchange as may be prescribed from time to time in such rules and regulations;

(2) file with the trustee and the SEC, in accordance with rules and regulations prescribed from time to time by the SEC, such additional information, documents and reports with respect to compliance by us with the conditions and covenants of the indenture as may be required from time to time by such rules and regulations; and

(3) transmit to all holders, as their names and addresses appear in the security register, within 30 days after the filing thereof with the trustee, in the manner and to the extent provided in Section 313(c) of the Trust Indenture Act of 1939, as amended, such summaries of any information, documents and reports required to be filed by us pursuant to clauses (1) and (2) of this paragraph as may be required by rules and regulations prescribed from time to time by the SEC.

Governing Law

The notes will be governed by and construed in accordance with the laws of the State of New York.

Book-Entry Delivery and Settlement

Settlement for the notes will be made by the underwriters in immediately available funds. All payments of principal, premium, if any, and interest will be made by us in immediately available funds.

The notes will trade in the Same-Day Funds Settlement System maintained by DTC until maturity or earlier redemption, and secondary market trading activity in the notes will therefore be required by DTC to settle in immediately available funds. No assurance can be given as to the effect, if any, of settlement in immediately available funds on trading activity in the notes.

Because of time-zone differences, credits of notes received in Clearstream Banking, société anonyme (“Clearstream”), or Euroclear Bank, S.A./N.V. (“Euroclear”), as a result of a transaction with a DTC participant will be made during subsequent securities settlement processing and dated the business day following the DTC settlement date. Such credits or any transactions in such notes settled during such processing will be reported to the relevant Clearstream or Euroclear participants on such business day. Cash received in Clearstream or Euroclear as a result of sales of notes by or through a Clearstream participant or a Euroclear participant to a DTC participant will be received with value on the DTC settlement date but will be available in the relevant Clearstream or Euroclear cash account only as of the business day following settlement in DTC.

Although DTC, Clearstream and Euroclear have agreed to the foregoing procedures in order to facilitate transfers of notes among participants of DTC, Clearstream and Euroclear, they are under no obligation to perform or continue to perform such procedures and such procedures may be discontinued at any time.

CERTAIN U.S. FEDERAL INCOME TAX CONSIDERATIONS

The following summary discusses certain U.S. federal income tax consequences of the acquisition, ownership and disposition of the notes. This discussion is based upon the Internal Revenue Code of 1986, as amended (the "Code"), the applicable proposed or promulgated Treasury regulations, and the applicable judicial and administrative interpretations, all as in effect as of the date hereof and all of which are subject to change, possibly with retroactive effect, and to differing interpretations. This discussion is applicable only to holders of notes who purchase the notes in the initial offering at their original issue price and deals only with the notes held as capital assets for U.S. federal income tax purposes (generally, property held for investment) and not held as part of a straddle, a hedge, a conversion transaction or other integrated investment. This discussion is a summary intended for general information only, and does not address all of the tax consequences that may be relevant to holders of notes in light of their particular circumstances, or to certain types of holders (such as banks and other financial institutions, insurance companies, tax-exempt entities, partnerships and other pass-through entities for U.S. federal income tax purposes or investors who hold the notes through such pass-through entities, certain former citizens or residents of the United States, "controlled foreign corporations," "passive foreign investment companies," traders in securities that elect to use a mark-to-market method of accounting for their securities holdings, dealers in securities or currencies, regulated investment companies, real estate investment trusts, corporations that accumulate earnings to avoid U.S. federal income tax, persons subject to the alternative minimum tax, persons subject to special tax accounting rules as a result of any item of gross income with respect to the notes being taken into account in an applicable financial statement, or U.S. Holders (as defined below) whose functional currency is not the U.S. dollar). Moreover, this discussion does not describe any state, local or non-U.S. tax implications, or any aspect of U.S. federal tax law other than income taxation. We have not and will not seek any rulings or opinions from the Internal Revenue Service ("IRS") or counsel regarding the matters discussed below. There can be no assurances that the IRS will not take positions concerning the tax consequences of the purchase, ownership or disposition of the notes that are different from those discussed below.

HOLDERS SHOULD CONSULT THEIR OWN TAX ADVISORS WITH RESPECT TO THE PARTICULAR U.S. FEDERAL INCOME TAX CONSEQUENCES TO THEM OF THE ACQUISITION, OWNERSHIP AND DISPOSITION OF THE NOTES AND THE TAX CONSEQUENCES UNDER STATE, LOCAL, NON-U.S. AND OTHER U.S. FEDERAL TAX LAWS (INCLUDING ESTATE TAX CONSEQUENCES) AND THE POSSIBLE EFFECTS OF CHANGES IN THE U.S. FEDERAL INCOME TAX LAWS.

As used herein, a "U.S. Holder" means a beneficial owner of notes that is, for U.S. federal income tax purposes, (a) an individual citizen or resident of the United States, (b) a corporation (or other entity treated as a corporation for U.S. federal income tax purposes) created or organized in or under the laws of the United States, any State thereof or the District of Columbia, (c) an estate, the income of which is subject to U.S. federal income taxation regardless of its source, or (d) a trust, if (1) a court within the United States is able to exercise primary supervision over the trust's administration and one or more U.S. persons have the authority to control all of its substantial decisions or (2) a valid election to be treated as a U.S. person is in effect under the relevant Treasury regulations with respect to such trust. A "Non-U.S. Holder" is an individual, corporation, estate, or trust that is a beneficial owner of the notes and is not a U.S. Holder. A Non-U.S. Holder who is an individual present in the United States for 183 days or more in the taxable year of disposition of a note, and who is not otherwise a resident of the United States for U.S. federal income tax purposes, may be subject to special tax provisions and is urged to consult his or her own tax advisor regarding the U.S. federal income tax consequences of the ownership and disposition of a note.

The U.S. federal income tax treatment of partners in partnerships holding notes generally will depend on the activities of the partnership and the status of the partner. Prospective investors that are

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partnerships (or entities treated as partnerships for U.S. federal income tax purposes) should consult their own tax advisors regarding the U.S. federal income tax consequences to them and their partners of the acquisition, ownership and disposition of the notes.

U.S. Federal Income Taxation of U.S. Holders

Payments of Interest. It is expected, and the rest of this discussion assumes, that the notes will be issued without original issue discount for U.S. federal income tax purposes. Accordingly, a U.S. Holder must include in gross income, as ordinary interest income, the stated interest on the notes at the time such interest accrues or is received in accordance with the U.S. Holder's regular method of accounting for U.S. federal income tax purposes. If, however, the notes' "stated redemption price at maturity" (generally, the sum of all payments required under the note other than payments of stated interest) exceeds the issue price by more than a de minimis amount, a U.S. Holder will be required to include such excess in income as original issue discount, as it accrues, in accordance with a constant yield method based on a compounding of interest before the receipt of cash payments attributable to this income.

Sale, Retirement or Other Taxable Disposition. Upon the sale, retirement or other taxable disposition of a note, a U.S. Holder generally will recognize taxable gain or loss equal to the difference between (a) the sum of cash plus the fair market value of other property received on the sale, retirement or other taxable disposition (except to the extent such cash or property is attributable to accrued but unpaid interest, which will be treated in the manner described above under "Payments of Interest") and (b) the U.S. Holder's adjusted tax basis in the note. A U.S. Holder's adjusted tax basis in a note generally will equal the amount paid for the note, reduced by any principal payments with respect to the note received by the U.S. Holder. Gain or loss recognized on the sale, retirement or other taxable disposition of a note generally will be capital gain or loss and will be long-term capital gain or loss if, at the time of sale, retirement or other taxable disposition, the note has been held for more than one year. Certain U.S. Holders (including individuals) are currently eligible for preferential rates of U.S. federal income tax in respect of long-term capital gain. The deductibility of capital losses by U.S. Holders is subject to limitations under the Code.

Medicare Tax and Reporting Obligations . A U.S. person that is an individual or estate, or a trust that does not fall into a special class of trusts that is exempt from such tax is subject to a 3.8% tax on the lesser of (1) the U.S. person's "net investment income" for the relevant taxable year and (2) the excess of the U.S. person's modified gross income for the taxable year over a certain threshold (which in the case of individuals will be between $125,000 and $250,000 depending on the individual's circumstances). Net investment income generally includes interest income and net gains from the disposition of the notes, unless such interest income or net gains are derived in the ordinary course of the conduct of a trade or business (other than a trade or business that consists of certain passive or trading activities). A U.S. Holder that is an individual, estate or trust should consult its tax advisor regarding the applicability of the Medicare tax to its income and gains in respect of its investment in the notes.

U.S. Federal Income Taxation of Non-U.S. Holders

Payments of Interest. Subject to the discussion of backup withholding below and the Foreign Account Tax Compliance Act below and provided that a Non-U.S. Holder's income and gains in respect of a note are not effectively connected with the conduct by the Non-U.S. Holder of a U.S. trade or business (or, in the case of an applicable tax treaty, attributable to the Non-U.S. Holder's permanent establishment in the United States), payments of interest on a note to the Non-U.S. Holder generally will not be subject to U.S. federal income or withholding tax, provided that (a) the Non-U.S. Holder does not own, directly or constructively, 10% or more of the total combined voting power of all classes of our stock entitled to vote within the meaning of section 871(h)(3) of the Code and the Treasury regulations thereunder, (b) the Non-U.S. Holder is not, for U.S. federal income tax purposes, a “controlled foreign corporation” related, directly or constructively, to us through stock ownership, (c) the Non-U.S. Holder is not a bank receiving interest described in section 881(c)(3)(A) of the Code and (d) certain certification requirements (as described below) are met.

Under the Code and the applicable Treasury regulations, in order to satisfy the certification requirements and obtain an exemption from U.S. federal withholding tax, either (a) a Non-U.S. Holder must provide its name and address and certify, under penalties of perjury, that such Non-U.S. Holder is not a U.S. person or (b) a securities clearing organization, bank or other financial institution that holds customers’ securities in the ordinary course of its trade or business (a “Financial Institution”), and that holds the notes on behalf of the Non-U.S. Holder, must certify, under penalties of perjury, that such certificate has been received from such Non-U.S. Holder by such Financial Institution or by another Financial Institution between such Financial Institution and such Non-U.S. Holder and, if required, must furnish the payor with a copy thereof. Generally, the foregoing certification requirement may be met if a Non-U.S. Holder delivers a properly executed IRS Forms W-8BEN or W-8BEN-E or substitute Forms W-8BEN or W-8BEN-E or the appropriate successor form to the payor. Special rules apply to foreign partnerships, estates and trusts and other intermediaries, and in certain circumstances certifications as to foreign status of partners, trust owners or beneficiaries may have to be provided. In addition, special rules apply to qualified intermediaries that enter into withholding agreements with the IRS.

Payments of interest on a note that do not satisfy all of the foregoing requirements generally will be subject to U.S. federal withholding tax at a rate of 30%, unless either: (a) an applicable income tax treaty reduces or eliminates such tax, and the Non-U.S. Holder claims the benefit of that treaty by providing a properly completed and duly executed IRS Form W-8BEN or W-8BEN-E (or suitable successor or substitute form) establishing qualification for benefits under the treaty, or (b) the interest is effectively connected with the Non-U.S. Holder’s conduct of a trade or business in the United States and the Non-U.S. Holder provides an appropriate statement to that effect on a properly completed and duly executed IRS Form W-8ECI (or suitable successor form).

A Non-U.S. Holder generally will be subject to U.S. federal income tax in the same manner as a U.S. Holder with respect to interest on a note (and the 30% withholding tax described above will not apply provided the duly executed IRS Form W-8ECI is provided to us or our paying agent) if such interest is effectively connected with a U.S. trade or business conducted by the Non-U.S. Holder. If a Non-U.S. Holder is eligible for the benefits of an income tax treaty between the United States and its country of residence, and the Non-U.S. Holder satisfies certain certification requirements, any interest income that is effectively connected with a U.S. trade or business will be subject to U.S. federal income tax in the manner specified by the treaty and generally will only be subject to tax on a net basis if such income is attributable to a permanent establishment (or a fixed base in the case of an individual) maintained by the Non-U.S. Holder in the United States. Under certain circumstances, effectively connected interest income received by a corporate Non-U.S. Holder may be subject to an additional “branch profits tax” at a 30% rate (or a lower applicable treaty rate, provided certain certification requirements are met). Non-U.S. Holders should consult their tax advisors about any applicable income tax treaties, which may provide for an exemption from or a lower rate of withholding tax, exemption from or reduction of branch profits tax, or other rules different from those described above.

Sale, Retirement or Other Disposition. Subject to the discussion of backup withholding below, a Non-U.S. Holder generally will not be subject to U.S. federal income or withholding tax on any gain recognized on the sale, retirement or other disposition of the notes so long as the holder provides us or the paying agent with the appropriate certification, unless (a) the Non-U.S. Holder is an individual who is present in the United States for 183 or more days in the taxable year of disposition (even though such holder is not considered a resident of the United States) and certain other conditions are met, or (b) the gain is effectively connected with the conduct of a U.S. trade or business by the Non-U.S. Holder (and, if an income tax treaty applies, is attributable to a permanent establishment or fixed base maintained by the Non-U.S. Holder in the United States). If the first exception applies, the Non-U.S. Holder generally will be subject to U.S. federal income tax at a rate of 30% on the amount by which its U.S.-source capital gains exceed its U.S.-source capital losses. If the second exception applies, the Non-U.S. Holder will generally be subject to U.S. federal income tax on the net gain derived from the sale or other disposition of the notes in the same manner as a U.S. Holder. In addition, corporate Non-U.S. Holders may be subject to a 30% branch profits tax on any effectively connected earnings and profits. If a Non-U.S. Holder is eligible for the benefits of an income tax treaty between the United States and its country of residence, the U.S. federal income tax treatment of any such gain may be modified in the manner specified by the treaty.

Information Reporting and Backup Withholding

U.S. Holders. Generally, information reporting will apply to payments of principal and interest on the notes to a U.S. Holder and to the proceeds of a sale or other disposition of the notes, unless the U.S. Holder is an exempt recipient (such as a corporation). Backup withholding generally will apply to such payments unless a U.S. Holder (a) is an exempt recipient and, when required, demonstrates this fact, or (b) provides the payor with its taxpayer identification number ("TIN"), certifies that the TIN provided to the payor is correct (typically by providing such certification on IRS Form W-9) and that the U.S. Holder has not been notified by the IRS that such U.S. Holder is subject to backup withholding due to underreporting of interest or dividends, and otherwise complies with applicable requirements of the backup withholding rules. Any amount withheld under the backup withholding rules generally will be allowed as a refund or credit against a U.S. Holder's U.S. federal income tax liability, provided that the required information is timely furnished to the IRS.

Non-U.S. Holders. When required, we or our paying agent will report payments of interest on the notes to a Non-U.S. Holder and the amount of any tax withheld from such payments annually to the IRS and to the Non-U.S. Holder. Copies of these information returns may be made available by the IRS to the tax authorities of the country in which the Non-U.S. Holder is a resident under the provisions of an applicable tax treaty. Backup withholding of U.S. federal income tax will generally not apply to payments of interest on the notes to a Non-U.S. Holder if the Non-U.S. Holder certifies under penalties of perjury that it is not a U.S. person or otherwise establishes an exemption, provided that the payor does not have actual knowledge or reason to know that such certification is unreliable or that the conditions of the exemption are in fact not satisfied.

Payments of the proceeds of the sale or other disposition of the notes by or through a foreign office of a U.S. broker or of a foreign broker with certain specified U.S. connections will be subject to information reporting requirements, but generally not backup withholding, unless the broker has evidence in its records that the payee is not a U.S. person and the broker has no actual knowledge or reason to know to the contrary. Payments of the proceeds of a sale or other disposition of the notes by or through the U.S. office of a broker will be subject to information reporting and backup withholding unless the payee certifies under penalties of perjury that it is not a U.S. person or otherwise establishes an exemption, provided that the payor does not have actual knowledge or reason to know that such certification is unreliable or that the conditions of the exemption are in fact not satisfied.

Any amount withheld under the backup withholding rules generally will be allowed as a refund or credit against a Non-U.S. Holder's U.S. federal income tax liability, provided that the required information is timely furnished to the IRS.

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Foreign Account Tax Compliance Act

Under sections 1471 through 1474 of the Code and the Treasury regulations promulgated thereunder (such sections commonly referred to as the “Foreign Account Tax Compliance Act” or “FATCA”), withholding taxes may apply to certain types of payments made to “foreign financial institutions” (as specially defined in the Code) and certain other non-U.S. entities. Specifically, a 30% U.S. federal withholding tax may be imposed on payments of interest made to a foreign financial institution or to a non-financial foreign entity, unless (1) the foreign financial institution undertakes certain diligence and reporting, (2) the non-financial foreign entity either certifies it does not have any substantial U.S. owners or furnishes identifying information regarding each substantial U.S. owner, or (3) the foreign financial institution or non-financial foreign entity otherwise qualifies for an exemption from these rules. If the payee is a foreign financial institution and is subject to the diligence and reporting requirements in clause (1) above, then, pursuant to an agreement between it and the U.S. Treasury, it must, among other things, identify accounts held by certain U.S. persons or U.S.-owned foreign entities, annually report certain information about such accounts, and withhold 30% on certain payments to non-compliant foreign financial institutions and certain other account holders. An applicable intergovernmental agreement regarding FATCA between the United States and a non-U.S. entity’s jurisdiction may modify the general rules described above. Pursuant to recently proposed regulations, the Treasury Department has indicated its intent to eliminate the requirements under FATCA of withholding on gross proceeds from the sale, exchange, maturity or other disposition of relevant financial instruments. The Treasury Department has indicated that taxpayers may rely on these proposed regulations pending their finalization. Prospective investors should consult their tax advisors regarding FATCA.

UNDERWRITING

We are offering the notes described in this prospectus supplement through a number of underwriters. BNP Paribas Securities Corp., CIBC World Markets Corp., Credit Agricole Securities (USA) Inc. and Wells Fargo Securities, LLC are acting as the representatives of the underwriters. We have entered into a firm commitment underwriting agreement with the representatives. Subject to the terms and conditions of the underwriting agreement, we have agreed to sell to the underwriters, and each underwriter has severally agreed to purchase, the aggregate principal amount of notes listed next to its name in the following table:

Underwriter	Principal Amount of the Notes
BNP Paribas Securities Corp.	$ 64,125,000
CIBC World Markets Corp.	64,125,000
Credit Agricole Securities (USA) Inc.	64,125,000
Wells Fargo Securities, LLC	64,125,000
Mizuho Securities USA LLC	43,500,000
MUFG Securities Americas Inc.	43,500,000
TD Securities (USA) LLC	43,500,000
Regions Securities LLC	31,500,000
BB&T Capital Markets, a division of BB&T Securities, LLC	15,750,000
The Williams Capital Group, L.P.	15,750,000
Total	$ 450,000,000

The underwriting agreement is subject to a number of terms and conditions and provides that the underwriters must buy all of the notes if they buy any of them. The underwriters will sell the notes to the public when and if the underwriters buy the notes from us.

The underwriters reserve the right to withdraw, cancel or modify offers to the public and to reject orders in whole or in part.

The underwriters have advised us that they propose initially to offer the notes to the public at the public offering prices set forth on the cover of this prospectus supplement, and to certain dealers at such price less a concession not in excess of 0.500% of the principal amount of the notes. The underwriters may allow, and such dealers may reallow, a concession not in excess of 0.175% of the principal amount of the notes to certain other dealers. After the public offering of the notes, the public offering price and other selling terms may be changed.

We estimate that our total expenses of the offering, excluding the underwriting discount, will be approximately $1 million.

We have agreed to indemnify the several underwriters against, or contribute to payments that the underwriters may be required to make in respect of, certain liabilities, including liabilities under the Securities Act of 1933, as amended.

The notes are a new issue of securities with no established trading market. The notes will not be listed on any securities exchange or on any automated dealer quotation system. The underwriters may make a market in the notes after completion of the offering, but will not be obligated to do so and may discontinue any market-making activities at any time without notice. No assurance can be given as to the liquidity of the trading market for the notes or that an active public market for the notes will develop. If an active public market for the notes does not develop, the market price and liquidity of the notes may be adversely affected.

In connection with the offering of the notes, certain of the underwriters may engage in transactions that stabilize, maintain or otherwise affect the price of the notes. Specifically, the underwriters may over allot in connection with the offering, creating a short position. In addition, the underwriters may bid for, and purchase, the notes in the open market to cover short positions or to stabilize the price of the notes. Any of these activities may stabilize or maintain the market price of the notes above independent market levels, but no representation is made hereby of the magnitude of any effect that the transactions described above may have on the market price of the notes. The underwriters will not be required to engage in these activities, but may engage in these activities, or may end any of these activities, at any time without notice.

The underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, investment research, principal investment, hedging, financing and brokerage activities. In the ordinary course of business, certain of the underwriters or their affiliates have provided and may in the future provide commercial, financial advisory or investment banking services for us and our subsidiaries for which they have received or will receive customary compensation. Certain of the underwriters are lenders under our revolving credit facilities.

In the ordinary course of their various business activities, the underwriters and their respective affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers, and such investment and securities activities may involve securities and/or instruments of the issuer. Certain of the underwriters or their affiliates that have a lending relationship with us routinely hedge, or may hedge, their credit exposure to us consistent with their customary risk management policies. Typically, such underwriters and their affiliates would hedge such exposure by entering into transactions which consist of either the purchase of credit default swaps or the creation of short positions in our securities, including potentially the notes offered hereby. Any such credit default swaps or short positions could adversely affect future trading prices of the notes offered hereby. The underwriters and their respective affiliates may also make investment recommendations and/or publish or express independent research views in respect of such securities or instruments and may at any time hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments.

We expect that delivery of the notes will be made against payment therefor on or about March 4, 2019, which will be the fifth business day following the date of the pricing of the notes (such settlement cycle being referred to as “T+5”). Under Rule 15c6-1 of the Securities Exchange Act of 1934, as amended, trades in the secondary market generally settle in two business days, and purchasers who wish to trade notes on the date of pricing or any subsequent date that is prior to the second trading day preceding the date on which we deliver the notes may be required, by virtue of the fact that the notes initially settle in T+5, to specify alternate settlement arrangements to prevent a failed settlement. Purchasers of the notes who wish to trade the notes prior to their date of delivery hereunder should consult their advisers.

Selling Restrictions

European Economic Area

This prospectus supplement has been prepared on the basis that any offer of notes in any Member State of the European Economic Area (“EEA”) will be made pursuant to an exemption under the Prospectus Directive from the requirement to publish a prospectus for offers of notes. Accordingly, any person making or intending to make an offer in that Member State of notes which are the subject of the offering contemplated in this prospectus supplement may only do so to legal entities which are qualified investors as defined in the Prospectus Directive, provided that no such offer of notes shall require Atmos or any of the underwriters to publish a prospectus pursuant to Article 3 of the Prospectus Directive or supplement a prospectus pursuant to Article 16 of the Prospectus Directive, in each case in relation to such offer.

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Neither Atmos nor the underwriters have authorized, nor do they authorize, the making of any offer of notes to any legal entity which is not a qualified investor as defined in the Prospectus Directive, provided that no such offer of notes shall require Atmos or any underwriter to publish a prospectus or supplement a prospectus pursuant to the Prospectus Directive for such offer. Neither Atmos nor the underwriters have authorized, nor do they authorize, the making of any offer of notes through any financial intermediary, other than offers made by the underwriters, which constitute the final placement of the notes contemplated in this prospectus supplement.

The expression “Prospectus Directive” means Directive 2003/71/EC (as amended or superseded), and includes any relevant implementing measure in the Member State concerned.

The notes are not intended to be offered, sold or otherwise made available to and should not be offered, sold or otherwise made available to any retail investor in the EEA. For these purposes, a retail investor means a person who is one (or more) of: (i) a retail client as defined in point (11) of Article 4(1) of Directive 2014/65/EU (as amended, “MiFID II”); or (ii) a customer within the meaning of Directive (EU) 2016/97 (as amended, the “Insurance Distribution Directive”), where that customer would not qualify as a professional client as defined in point (10) of Article 4(1) of MiFID II; or (iii) not a qualified investor as defined in the Prospectus Directive. Consequently no key information document required by Regulation (EU) No 1286/2014 (as amended, the “PRIIPs Regulation”) for offering or selling the notes or otherwise making them available to retail investors in the EEA has been prepared and therefore offering or selling the notes or otherwise making them available to any retail investor in the EEA may be unlawful under the PRIIPs Regulation. This prospectus supplement and the accompanying prospectus have been prepared on the basis that any offer of notes in any Member State of the EEA will be made pursuant to an exemption under the Prospectus Directive from the requirement to publish a prospectus for offers of notes.

United Kingdom

This prospectus supplement and the accompanying prospectus are for distribution only to, and are directed solely at, persons who are “qualified investors” (as defined in the Prospectus Directive) (i) who have professional experience in matters relating to investments falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005, as amended (the “Order”) and/or (ii) who are high net worth companies (or persons to whom it may otherwise be lawfully communicated) falling within Article 49(2)(a) to (d) of the Order (all such persons together being referred to as “relevant persons”). This prospectus supplement and the accompanying prospectus are directed only at relevant persons and must not be acted on or relied on by persons who are not relevant persons. Any investment or investment activity to which this prospectus supplement and the accompanying prospectus relate is available only to relevant persons and will be engaged in only with relevant persons. Any person who is not a relevant person should not act or rely on this prospectus supplement, the accompanying prospectus or any of their contents.

Canada

The notes may be sold in Canada only to purchasers purchasing, or deemed to be purchasing, as principal that are accredited investors, as defined in National Instrument 45-106 Prospectus Exemptions or subsection 73.3(1) of the Securities Act (Ontario), and are permitted clients, as defined in National Instrument 31-103 Registration Requirements, Exemptions and Ongoing Registrant Obligations. Any resale of the notes must be made in accordance with an exemption from, or in a transaction not subject to, the prospectus requirements of applicable securities laws. Securities legislation in certain provinces or territories of Canada may provide a purchaser with remedies for rescission or damages if this prospectus supplement (including any amendment thereto) contains a

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misrepresentation, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province or territory. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for particulars of these rights or consult with a legal advisor. Pursuant to section 3A.3 of National Instrument 33-105 Underwriting Conflicts (NI 33-105), the underwriters are not required to comply with the disclosure requirements of NI 33-105 regarding underwriter conflicts of interest in connection with this offering.

Switzerland

The notes may not be publicly offered in Switzerland and will not be listed on the SIX Swiss Exchange ("SIX") or on any other stock exchange or regulated trading facility in Switzerland. This prospectus supplement and the accompanying prospectus have been prepared without regard to the disclosure standards for issuance prospectuses under art. 652a or art. 1156 of the Swiss Code of Obligations or the disclosure standards for listing prospectuses under art. 27 ff. of the SIX Listing Rules or the listing rules of any other stock exchange or regulated trading facility in Switzerland. None of this prospectus supplement, the accompanying prospectus or any other offering or marketing material relating to the notes or the offering may be publicly distributed or otherwise made publicly available in Switzerland.

None of this prospectus supplement, the accompanying prospectus or any other offering or marketing material relating to the offering, the Company, the notes have been or will be filed with or approved by any Swiss regulatory authority. In particular, this prospectus supplement and the accompanying prospectus will not be filed with, and the offer of the notes will not be supervised by, the Swiss Financial Market Supervisory Authority FINMA ("FINMA"), and the offer of the notes has not been and will not be authorized under the Swiss Federal Act on Collective Investment Schemes ("CISA"). The investor protection afforded to acquirers of interests in collective investment schemes under the CISA does not extend to acquirers of the notes.

Singapore

This prospectus supplement and the accompanying prospectus have not been registered as a prospectus with the Monetary Authority of Singapore. Accordingly, this prospectus supplement, the accompanying prospectus and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the notes may not be circulated or distributed, nor may the notes be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor under Section 274 of the Securities and Futures Act, Chapter 289 of Singapore (the "SFA"), (ii) to a relevant person pursuant to Section 275(1), or any person pursuant to Section 275(1A), and in accordance with the conditions specified in Section 275, of the SFA or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA, in each case subject to compliance with the conditions set forth in the SFA.

Where the notes are subscribed or purchased under Section 275 of the SFA by a relevant person which is:

- a corporation (which is not an accredited investor (as defined in Section 4A of the SFA)) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or
- a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary of the trust is an individual who is an accredited investor,

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then the shares, debentures and units of shares and debentures of that corporation or the beneficiaries' rights and interest (howsoever described) in that trust shall not be transferred within six months after that corporation or that trust has acquired the notes pursuant to an offer made under Section 275 of the SFA except:

- to an institutional investor (for corporations, under Section 274 of the SFA) or to a relevant person defined in Section 275(2) of the SFA, or to any person pursuant to an offer that is made on terms that such shares, debentures and units of shares and debentures of that corporation or such rights and interest in that trust are acquired at a consideration of not less than S$200,000 (or its equivalent in a foreign currency) for each transaction, whether such amount is to be paid for in cash or by exchange of securities or other assets, and further for corporations, in accordance with the conditions specified in Section 275 of the SFA;
- where no consideration is or will be given for the transfer; or
- where the transfer is by operation of law.

Solely for the purposes of its obligations pursuant to sections 309B(1)(a) and 309B(1)(c) of the SFA, the Issuer has determined, and hereby notifies all relevant persons (as defined in Section 309A of the SFA) that the Notes are "prescribed capital markets products" (as defined in the Securities and Futures (Capital Markets Products) Regulations 2018) and Excluded Investment Products (as defined in MAS Notice SFA 04-N12: Notice on the Sale of Investment Products and MAS Notice FAA-N16: Notice on Recommendations on Investment Products).

Japan

The notes offered in this prospectus supplement and the accompanying prospectus have not been and will not be registered under the Financial Instruments and Exchange Law of Japan (Financial Instruments and Exchange Law). The notes have not been offered or sold and will not be offered or sold, directly or indirectly, in Japan or to or for the benefit of any resident of Japan (which term as used herein means any resident of Japan, including any corporation or other entity organized under the laws of Japan), or to others for re-offering or resale, directly or indirectly, in Japan or to a resident of Japan, except pursuant to an exemption from the registration requirements of, and in compliance with, the Financial Instruments and Exchange Law and any other applicable requirements of Japanese law.

Taiwan

The notes have not been and will not be registered with the Financial Supervisory Commission of Taiwan pursuant to relevant securities laws and regulations and may not be sold, issued or offered within Taiwan through a public offering or in circumstances which constitutes an offer within the meaning of the Securities and Exchange Act of Taiwan that requires a registration or approval of the Financial Supervisory Commission of Taiwan. No person or entity in Taiwan has been authorized to offer, sell, give advice regarding or otherwise intermediate the offering and sale of the notes in Taiwan.

Hong Kong

The notes may not be offered or sold by means of any document other than (i) in circumstances which do not constitute an offer to the public within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), or (ii) to "professional investors" within the meaning of the Securities and Futures Ordinance (Cap.571, Laws of Hong Kong) and any rules made thereunder, or (iii) in other circumstances which do not result in this prospectus supplement being a "prospectus" within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), and no advertisement, invitation

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or document relating to the notes may be issued or may be in the possession of any person for the purpose of issue (in each case whether in Hong Kong or elsewhere), which is directed at, or the contents of which are likely to be accessed or read by, the public in Hong Kong (except if permitted to do so under the laws of Hong Kong) other than with respect to notes which are or are intended to be disposed of only to persons outside Hong Kong or only to “professional investors” within the meaning of the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder.

United Arab Emirates

The notes have not been, and are not being, publicly offered, sold, promoted or advertised in the United Arab Emirates (including the Dubai International Financial Centre) other than in compliance with the laws of the United Arab Emirates (and the Dubai International Financial Centre) governing the issue, offering and sale of securities. Further, this prospectus does not constitute a public offer of securities in the United Arab Emirates (including the Dubai International Financial Centre) and is not intended to be a public offer. This prospectus has not been approved by or filed with the Central Bank of the United Arab Emirates, the Securities and Commodities Authority or the Dubai Financial Services Authority.

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LEGAL MATTERS

Gibson, Dunn & Crutcher LLP and Hunton Andrews Kurth LLP will opine for us as to the validity of the offered notes. The Underwriters are represented by Shearman & Sterling LLP, New York, New York.

EXPERTS

The consolidated financial statements of Atmos Energy appearing in Atmos Energy's Annual Report (Form 10-K) for the year ended September 30, 2018, including Schedule II appearing therein, and the effectiveness of Atmos Energy's internal control over financial reporting as of September 30, 2018 have been audited by Ernst & Young LLP, independent registered public accounting firm, as set forth in their reports thereon, included therein, and incorporated herein by reference. Such consolidated financial statements are incorporated herein by reference in reliance upon such reports given on the authority of such firm as experts in accounting and auditing.

With respect to the unaudited condensed consolidated interim financial information of Atmos Energy for the three-month periods ended December 31, 2018 and 2017, incorporated by reference in this prospectus, Ernst & Young LLP reported that they have applied limited procedures in accordance with professional standards for a review of such information. However, its separate report dated February 5, 2019, included in Atmos Energy's quarterly report on Form 10-Q for the quarterly period ended December 31, 2018, and incorporated by reference herein, states that they did not audit and they do not express an opinion on that interim financial information. Accordingly, the degree of reliance on their report on such information should be restricted in light of the limited nature of the review procedures applied. Ernst & Young LLP is not subject to the liability provisions of Section 11 of the Securities Act of 1933 (the "Act") for their report on the unaudited interim financial information because that report is not a "report" or a "part" of the Registration Statement prepared or certified by Ernst & Young LLP within the meaning of Sections 7 and 11 of the Act.

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PROSPECTUS

Atmos Energy Corporation

By this prospectus, we offer up to

$3,000,000,000

of debt securities and common stock.

We will provide specific terms of these securities in supplements to this prospectus. This prospectus may not be used to sell securities unless accompanied by a prospectus supplement. You should read this prospectus and the applicable prospectus supplement carefully before you invest.

Investing in these securities involves risks. See " Risk Factors " on page 3 of this prospectus, in the applicable prospectus supplement and in the documents incorporated by reference.

Our common stock is listed on the New York Stock Exchange under the symbol "ATO."

Our address is 1800 Three Lincoln Centre, 5430 LBJ Freeway, Dallas, Texas 75240, and our telephone number is (972) 934-9227.

The Securities and Exchange Commission and state securities regulators have not approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

This prospectus is dated November 13, 2018

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We have not authorized any other person to provide you with any information or to make any representation that is different from, or in addition to, the information and representations contained in this prospectus or in any of the documents that are incorporated by reference in this prospectus. We take no responsibility for, and can provide no assurances as to the reliability of, any other information that others may give you or representations that others may make. We are not making or soliciting an offer of any securities other than the securities described in this prospectus and any prospectus supplement. You should assume that the information appearing in this prospectus, as well as the information contained in any document incorporated by reference, is accurate as of the date of each such document only, unless the information specifically indicates that another date applies.

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The distribution of this prospectus may be restricted by law in certain jurisdictions. You should inform yourself about and observe any of these restrictions. This prospectus does not constitute, and may not be used in connection with, an offer or solicitation by anyone in any jurisdiction in which the offer or solicitation is not authorized, or in which the person making the offer or solicitation is not qualified to do so, or to any person to whom it is unlawful to make the offer or solicitation.

The terms "we," "our," "us," and "Atmos Energy" refer to Atmos Energy Corporation and its subsidiaries unless the context suggests otherwise. The term "you" refers to a prospective investor.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Statements contained or incorporated by reference in this prospectus that are not statements of historical fact are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"). Forward-looking statements are based on management's beliefs as well as assumptions made by, and information currently available to, management. Because such statements are based on expectations as to future results and are not statements of fact, actual results may differ materially from those stated. Important factors that could cause future results to differ include, but are not limited to:

- state and local regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions;
- increased federal regulatory oversight and potential penalties;
- possible increased federal, state and local regulation of the safety of our operations;
- the inherent hazards and risks involved in distributing, transporting and storing natural gas;
- the capital-intensive nature of our business;
- our ability to continue to access the credit and capital markets to execute our business strategy;
- market risks beyond our control affecting our risk management activities, including commodity price volatility, counterparty performance or creditworthiness and interest rate risk;
- the concentration of our operations in Texas;
- the impact of adverse economic conditions on our customers;
- changes in the availability and price of natural gas;
- the availability and accessibility of contracted gas supplies, interstate pipeline and/or storage services;
- increased competition from energy suppliers and alternative forms of energy;
- adverse weather conditions;
- increased costs of providing health care benefits, along with pension and postretirement health care benefits and increased funding requirements;
- the inability to continue to hire, train and retain operational, technical and managerial personnel;
- the impact of climate change or related additional legislation or regulation in the future;
- the threat of cyber-attacks or acts of cyber-terrorism that could disrupt our business operations and information technology systems or result in the loss or exposure of confidential or sensitive customer, employee or Company information;
- natural disasters, terrorist activities or other events; and
- other risks and uncertainties discussed in this prospectus, any accompanying prospectus supplement and our other filings with the Securities and Exchange Commission (the "SEC").

All of these factors are difficult to predict and many are beyond our control. Accordingly, while we believe our forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. When used in our documents or oral presentations, the words "anticipate," "believe," "estimate," "expect," "forecast," "goal," "intend," "objective," "plan," "projection," "seek," "strategy" or similar words are intended to identify forward-looking statements. We undertake no obligation to update or revise any of our forward-looking statements, whether as a result of new information, future events or otherwise.

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For additional factors you should consider generally and when evaluating these forward-looking statements, please see “Risk Factors” below, “Item 1A. Risk Factors” and “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” in our Annual Report on Form 10-K for the fiscal year ended September 30, 2018. See also “Incorporation of Certain Documents by Reference” on page 25 of this prospectus, as well as the applicable prospectus supplement.

RISK FACTORS

Investing in our debt securities or our common stock involves risks. Our business is influenced by many factors that are difficult to predict and beyond our control and that involve uncertainties that may materially affect our results of operations, financial condition or cash flows, or the value of these securities. These risks and uncertainties include those described in the risk factors and other sections of the documents that are incorporated by reference in this prospectus. Subsequent prospectus supplements may contain a discussion of additional risks applicable to an investment in us and the particular type of securities we are offering under the prospectus supplements. You should carefully consider all of the information contained in or incorporated by reference in this prospectus or in the applicable prospectus supplement before you invest in our debt securities or common stock.

ATMOS ENERGY CORPORATION

Atmos Energy Corporation, headquartered in Dallas, Texas, and incorporated in Texas and Virginia, is one of the country's largest natural-gas-only distributors based on number of customers. We deliver natural gas through regulated sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers in eight states located primarily in the South. We also operate one of the largest intrastate pipelines in Texas based on miles of pipe.

We manage and review our consolidated operations through the following three reportable segments:

- The *distribution segment* is primarily comprised of our regulated natural gas distribution and related sales operations in eight states.
- The *pipeline and storage segment* is comprised primarily of the pipeline and storage operations of our Atmos Pipeline—Texas division and our natural gas transmission operations in Louisiana.
- The *natural gas marketing segment* is comprised of our discontinued natural gas marketing business.

SECURITIES WE MAY OFFER

Types of Securities

The types of securities that we may offer and sell from time to time by this prospectus are:

- debt securities, which we may issue in one or more series and which may include provisions regarding conversion of the debt securities into our common stock; and
- common stock.

The aggregate initial offering price of all securities sold will not exceed $3,000,000,000. We will determine when we sell securities, the amounts of securities we will sell and the prices and other terms on which we will sell them. We may sell securities to or through underwriters, through agents or dealers or directly to purchasers. The offer and sale of securities by this prospectus is subject to receipt of satisfactory regulatory approvals in three states, all of which have been received and are currently in effect.

Prospectus Supplements

This prospectus provides you with a general description of the debt securities and common stock we may offer. Each time we offer securities, we will provide a prospectus supplement that will contain specific information about the terms of the offering. The prospectus supplement may also add to or change information contained in this prospectus. In that case, the prospectus supplement should be read as superseding this prospectus.

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In each prospectus supplement, which will be attached to the front of this prospectus, we will include, among other things, the following information:

- the type and amount of securities which we propose to sell;
- the initial public offering price of the securities;
- the names of the underwriters, agents or dealers, if any, through or to which we will sell the securities;
- the compensation, if any, of those underwriters, agents or dealers;
- if applicable, information about the securities exchanges or automated quotation systems on which the securities will be listed or traded;
- material United States federal income tax considerations applicable to the securities, where necessary; and
- any other material information about the offering and sale of the securities.

For more details on the terms of the securities, you should read the exhibits filed with our registration statement, of which this prospectus is a part. You should also read both this prospectus and the applicable prospectus supplement, together with additional information described under the heading "Where You Can Find More Information."

USE OF PROCEEDS

Except as may otherwise be stated in the applicable prospectus supplement, we intend to use the net proceeds from the sale of the securities that we may offer and sell from time to time by this prospectus for general corporate purposes, including for working capital, repaying indebtedness and funding capital projects and other growth.

DESCRIPTION OF DEBT SECURITIES

We may issue debt securities from time to time in one or more distinct series. This section summarizes the material terms that we anticipate will be common to all series of debt securities. Please note that the terms of any series of debt securities that we may offer may differ significantly from the common terms described in this prospectus. Many of the other terms of any series of debt securities that we offer, and any differences from the common terms described in this prospectus, will be described in the prospectus supplement for such securities to be attached to the front of this prospectus.

As required by U.S. federal law for all bonds and notes of companies that are publicly offered, a document called an indenture will govern any debt securities that we issue. An indenture is a contract between us and a financial institution acting as trustee on behalf of the purchasers of the debt securities. We have entered into an indenture with U.S. Bank National Association, as trustee (the "indenture"), which is subject to the Trust Indenture Act of 1939. The trustee under the indenture has the following two main roles:

- the trustee can enforce your rights against us if we default; there are some limitations on the extent to which the trustee acts on your behalf, which are described later in this prospectus; and
- the trustee will perform certain administrative duties for us, which include sending you interest payments and notices.

As this section is a summary of some of the terms of the debt securities we may offer under this prospectus, it does not describe every aspect of the debt securities. We urge you to read the indenture and the other documents we file with the SEC relating to the debt securities because the indenture for those securities and those other documents, and not this description, will define your rights as a holder of our debt securities. We filed a copy of the indenture with the SEC as an exhibit to our Current Report on Form 8-K filed March 26, 2009, and it is incorporated in this prospectus by reference. We may file any such other documents as exhibits to an annual, quarterly or current report that we file with the SEC following their execution. See "Where You Can Find More Information" for information on how to obtain copies of the indenture and any such other documents. References to the "indenture" mean the indenture that will define your rights as a holder of debt securities. Capitalized terms used in this section and not otherwise defined have the meanings set forth in the indenture.

General

The debt securities will be our unsecured obligations. Senior debt securities will rank equally with all of our other unsecured and unsubordinated indebtedness. Subordinated debt securities will rank junior to our senior indebtedness, including our credit facilities.

You should read the prospectus supplement that will describe the following terms of the series of debt securities offered by the prospectus supplement:

- the title of the debt securities and whether the debt securities will be senior debt securities or subordinated debt securities;
- the ranking of the debt securities;
- if the debt securities are subordinated, the terms of subordination;
- the aggregate principal amount of the debt securities, the percentage of their principal amount at which the debt securities will be issued, and the date or dates when the principal of the debt securities will be payable or how those dates will be determined or extended;
- the interest rate or rates, which may be fixed or variable, that the debt securities will bear, if any, how the rate or rates will be determined, and the periods when the rate or rates will be in effect;
- the date or dates from which any interest will accrue or how the date or dates will be determined, the date or dates on which any interest will be payable, whether and the terms under which payment of interest may be deferred, any regular record dates for these payments or how these dates will be determined and the basis on which any interest will be calculated, if other than on the basis of a 360-day year of twelve 30-day months;
- the place or places, if any, other than or in addition to New York City, of payment, transfer or exchange of the debt securities, and where notices or demands to or upon us in respect of the debt securities may be served;
- any optional redemption provisions and any restrictions on the sources of funds for redemption payments, which may benefit the holders of other securities;
- any sinking fund or other provisions that would obligate us to repurchase or redeem the debt securities;
- whether the amount of payments of principal of, any premium on, or interest on the debt securities will be determined with reference to an index, formula or other method, which could be based on one or more commodities, equity indices or other indices, and how these amounts will be determined;
- any modifications, deletions or additions to the events of default or covenants with respect to the debt securities described in this prospectus;
- if not the principal amount of the debt securities, the portion of the principal amount that will be payable upon acceleration of the maturity of the debt securities or how that portion will be determined;
- any modifications, deletions or additions to the provisions concerning defeasance and covenant defeasance contained in the indenture that will be applicable to the debt securities;

- any provisions granting special rights to the holders of the debt securities upon the occurrence of specified events;
- if other than the trustee, the name of the paying agent, security registrar or transfer agent for the debt securities;
- if we do not issue the debt securities in book-entry form only to be held by The Depository Trust Company, as depository, whether we will issue the debt securities in certificated form or the identity of any alternative depository;
- the person to whom any interest in a debt security will be payable, if other than the registered holder at the close of business on the regular record date;
- the denomination or denominations in which the debt securities will be issued, if other than denominations of $2,000 or any integral multiple of $1,000 in excess thereof;
- any provisions requiring us to pay Additional Amounts on the debt securities to any holder who is not a United States person in respect of any tax, assessment or governmental charge and, if so, whether we will have the option to redeem the debt securities rather than pay the Additional Amounts;
- whether the debt securities will be convertible into or exchangeable for other debt securities or common shares, and, if so, the terms and conditions upon which the debt securities will be so convertible or exchangeable, including the initial conversion or exchange price or rate or the method of calculation, how and when the conversion price or exchange ratio may be adjusted, whether conversion or exchange is mandatory, at the option of the holder or at our option, the conversion or exchange period and any other provision related to the debt securities; and
- any other material terms of the debt securities or the indenture, which may not be consistent with the terms set forth in this prospectus.

For purposes of this prospectus, any reference to the payment of principal of, any premium on, or interest on the debt securities will include Additional Amounts if required by the terms of the debt securities.

The indenture does not limit the amount of debt securities that we are authorized to issue from time to time. The indenture also provides that there may be multiple series of debt securities issued thereunder and more than one trustee thereunder, each for one or more series of debt securities. If a trustee is acting under the indenture with respect to more than one series of debt securities, the debt securities for which it is acting would be treated as if issued under separate indentures. If there is more than one trustee under the indenture, the powers and trust obligations of each trustee will apply only to the debt securities of the separate series for which it is trustee.

We may issue debt securities with terms different from those of debt securities already issued. Without the consent of the holders of the outstanding debt securities, we may reopen a previous issue of a series of debt securities and issue additional debt securities of that series unless the reopening was restricted when we created that series.

There is no requirement that we issue debt securities in the future under the indenture, and we may use other indentures or documentation, containing different provisions in connection with future issues of other debt securities.

We may issue the debt securities as "original issue discount securities," which are debt securities, including any zero-coupon debt securities, that are issued and sold at a discount from their stated principal amount. Original issue discount securities provide that, upon acceleration of their maturity, an amount less than their principal amount will become due and payable. We will describe the U.S. federal income tax consequences and other considerations applicable to original issue discount securities in any prospectus supplement relating to them.

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Holders of Debt Securities

Book-Entry Holders. We will issue debt securities in book-entry form only, unless we specify otherwise in the applicable prospectus supplement. This means the debt securities will be represented by one or more global securities registered in the name of a financial institution that holds them as depository on behalf of other financial institutions that participate in the depository's book-entry system. These participating institutions, in turn, hold beneficial interests in the debt securities on behalf of themselves or their customers.

Under the indenture, we will recognize as a holder only the person in whose name a debt security is registered. Consequently, for debt securities issued in global form, we will recognize only the depository as the holder of the debt securities and we will make all payments on the debt securities to the depository. The depository passes along the payments it receives to its participants, which in turn pass the payments along to their customers who are the beneficial owners. The depository and its participants do so under agreements they have made with one another or with their customers; they are not obligated to do so under the terms of the debt securities. As a result, you will not own the debt securities directly. Instead, you will own beneficial interests in a global security, through a bank, broker or other financial institution that participates in the depository's book-entry system or holds an interest through a participant. As long as the debt securities are issued in global form, you will be an indirect holder, and not a holder, of the debt securities.

Street Name Holders. In the future we may terminate a global security or issue debt securities initially in non-global form. In these cases, you may choose to hold your debt securities in your own name or in "street name." Debt securities held in street name would be registered in the name of a bank, broker or other financial institution that you choose, and you would hold only a beneficial interest in those debt securities through an account you maintain at that institution.

For debt securities held in street name, we will recognize only the intermediary banks, brokers and other financial institutions in whose names the debt securities are registered as the holders of those debt securities, and we will make all payments on those debt securities to them. These institutions pass along the payments they receive to their customers who are the beneficial owners, but only because they agree to do so in their customer agreements or because they are legally required to do so. If you hold debt securities in street name you will be an indirect holder, and not a holder, of those debt securities.

Legal Holders. Our obligations, as well as the obligations of the trustee and those of any third parties employed by us or the trustee, run only to the legal holders of the debt securities. We do not have obligations to you if you hold beneficial interests in global securities, in street name or by any other indirect means. This will be the case whether you choose to be an indirect holder of a debt security or have no choice because we are issuing the debt securities only in global form.

For example, once we make a payment or give a notice to the holder, we have no further responsibility for the payment or notice, even if that holder is required, under agreements with depository participants or customers or by law, to pass it along to the indirect holders but does not do so. Similarly, if we want to obtain the approval of the holders for any purpose (for example, to amend the indenture or to relieve us of the consequences of a default or of our obligation to comply with a particular provision of the indenture) we would seek the approval only from the holders, and not the indirect holders, of the debt securities. Whether and how the holders contact the indirect holders is up to the holders.

When we refer to you, we mean those who invest in the debt securities being offered by this prospectus, whether they are the holders or only indirect holders of those debt securities. When we refer to your debt securities, we mean the debt securities in which you hold a direct or indirect interest.

Special Considerations for Indirect Holders. If you hold debt securities through a bank, broker or other financial institution, either in book-entry form or in street name, you should check with your own institution to find out:

- how it handles securities payments and notices;

- whether it imposes fees or charges;
- how it would handle a request for the holders' consent, if ever required;
- whether and how you can instruct it to send you debt securities registered in your own name so you can be a holder, if that is permitted in the future;
- how it would exercise rights under the debt securities if there were a default or other event triggering the need for holders to act to protect their interests; and
- if the debt securities are in book-entry form, how the depository's rules and procedures will affect these matters.

Global Securities

What is a Global Security? We will issue each debt security under the indenture in book-entry form only, unless we specify otherwise in the applicable prospectus supplement. A global security represents one or any other number of individual debt securities. Generally, all debt securities represented by the same global securities will have the same terms. We may, however, issue a global security that represents multiple debt securities that have different terms and are issued at different times. We call this kind of global security a master global security.

Each debt security issued in book-entry form will be represented by a global security that we deposit with and register in the name of a financial institution or its nominee that we select. The financial institution that we select for this purpose is called the depository. Unless we specify otherwise in the applicable prospectus supplement, The Depository Trust Company, New York, New York, known as DTC, will be the depository for all debt securities issued in book-entry form.

A global security may not be transferred to or registered in the name of anyone other than the depository or its nominee, unless special termination situations arise. We describe those situations below under "Special Situations When a Global Security Will Be Terminated." As a result of these arrangements, the depository, or its nominee, will be the sole registered owner and holder of all debt securities represented by a global security, and investors will be permitted to own only beneficial interests in a global security. Beneficial interests must be held by means of an account with a broker, bank or other financial institution that in turn has an account with the depository or with another institution that does. Thus, if your security is represented by a global security, you will not be a holder of the debt security, but only an indirect holder of a beneficial interest in the global security.

Special Considerations for Global Securities. We do not recognize an indirect holder as a holder of debt securities and instead deal only with the depository that holds the global security. The account rules of your financial institution and of the depository, as well as general laws relating to securities transfers, will govern your rights relating to a global security.

If we issue debt securities only in the form of a global security, you should be aware of the following:

- you cannot cause the debt securities to be registered in your name, and cannot obtain non-global certificates for your interest in the debt securities, except in the special situations that we describe below;
- you will be an indirect holder and must look to your own bank or broker for payments on the debt securities and protection of your legal rights relating to the debt securities, as we describe under "Holders of Debt Securities" above;
- you may not be able to sell interests in the debt securities to some insurance companies and to other institutions that are required by law to own their securities in non-book-entry form;

- you may not be able to pledge your interest in a global security in circumstances where certificates representing the debt securities must be delivered to the lender or other beneficiary of the pledge in order for the pledge to be effective;
- the depository's policies, which may change from time to time, will govern payments, transfers, exchanges and other matters relating to your interest in a global security. We and the trustee have no responsibility for any aspect of the depository's actions or for its records of ownership interests in a global security. We and the trustee also do not supervise the depository in any way;
- DTC requires, and other depositories may require, that those who purchase and sell interests in a global security within its book-entry system use immediately available funds and your broker or bank may require you to do so as well; and
- financial institutions that participate in the depository's book-entry system, and through which you hold your interest in a global security, may also have their own policies affecting payments, notices and other matters relating to the debt security. Your chain of ownership may contain more than one financial intermediary. We do not monitor and are not responsible for the actions of any of those intermediaries.

Special Situations When a Global Security Will Be Terminated. In a few special situations described below, a global security will be terminated and interests in it will be exchanged for certificates in non-global form representing the debt securities it represented. After that exchange, you will be able to choose whether to hold the debt securities directly or in street name. You must consult your own bank or broker to find out how to have your interests in a global security transferred on termination to your own name, so that you will be a holder. We have described the rights of holders and street name investors above under "Holders of Debt Securities."

The special situations for termination of a global security are as follows:

- if the depository notifies us that it is unwilling, unable or no longer qualified to continue as depository for that global security and we do not appoint another institution to act as depository within 60 days;
- if we notify the trustee that we wish to terminate that global security; or
- if an event of default has occurred with regard to debt securities represented by that global security and has not been cured or waived. We discuss defaults later under "Events of Default."

If a global security is terminated, only the depository, and not we or the trustee, is responsible for deciding the names of the intermediary banks, brokers and other financial institutions in whose names the debt securities represented by the global security are registered, and, therefore, who will be the holders of those debt securities.

Covenants

This section summarizes the material covenants in the indenture. Please refer to the applicable prospectus supplement for information about any changes to our covenants, including any addition or deletion of a covenant, and to the indenture for information on other covenants not described in this prospectus or the applicable prospectus supplement.

Limitations on Liens. We covenant in the indenture that we will not, and will not permit any of our Restricted Subsidiaries to, create, incur, issue or assume any Indebtedness secured by any Lien on any Principal Property, or on shares of stock or Indebtedness of any Restricted Subsidiary, known as Restricted Securities, without making effective provision for the Outstanding Securities, other than debt securities of any series not entitled to the benefit of this covenant, to be secured by a Lien equally and ratably with, or prior to (or in the case of debt securities of any series that are subordinated in right of payment to the Indebtedness secured by such

Lien, by a Lien subordinated to), the Lien securing such Indebtedness for so long as the Indebtedness is so secured, except that the foregoing restriction does not apply to:

- any Lien existing on the date of the first issuance of debt securities of the relevant series under the indenture, or existing on such other date as may be specified in any supplemental indenture, board resolution or officers' certificate with respect to such series;
- any Lien on any Principal Property or Restricted Securities of any person existing at the time such person is merged or consolidated with or into us or a Restricted Subsidiary, or becomes a Restricted Subsidiary, or arising thereafter otherwise than in connection with the borrowing of money arranged thereafter and pursuant to contractual commitments entered into prior to and not in contemplation of such person's becoming a Restricted Subsidiary;
- any Lien on any Principal Property or Restricted Securities existing at the time we or a Restricted Subsidiary acquire such Principal Property or Restricted Securities, whether or not such Lien is assumed by us or such Restricted Subsidiary, provided that no such Lien may extend to any other Principal Property or Restricted Securities of ours or any Restricted Subsidiary;
- any Lien on any Principal Property, including any improvements on an existing Principal Property, of ours or any Restricted Subsidiary, and any Lien on Restricted Securities of a Restricted Subsidiary that was formed or is held for the purpose of acquiring and holding such Principal Property, in each case to secure all or any part of the cost of acquisition, development, operation, construction, alteration, repair or improvement of all or any part of such Principal Property, or to secure Indebtedness incurred by us or a Restricted Subsidiary for the purpose of financing all or any part of such cost; provided that such Lien is created prior to, at the time of, or within 12 months after the latest of, the acquisition, completion of construction or improvement or commencement of commercial operation of that Principal Property and, provided further, that no such Lien may extend to any other Principal Property of ours or any Restricted Subsidiary, other than any currently unimproved real property on which the Principal Property has been constructed or developed or the improvement is located;
- any Lien on any Principal Property or Restricted Securities to secure Indebtedness owed to us or to a Restricted Subsidiary;
- any Lien in favor of a governmental body to secure advances or other payments under any contract or statute or to secure Indebtedness incurred to finance the purchase price or cost of constructing or improving the property subject to such Lien;
- any Lien created in connection with a project financed with, and created to secure, Non-Recourse Indebtedness;
- any extension, renewal, substitution or replacement, or successive extensions, renewals, substitutions or replacements, in whole or in part, of any Lien referred to in any of the bullet points above, provided that the Indebtedness secured thereby may not exceed the principal amount of Indebtedness that is secured at the time of the renewal or refunding, plus any premium, cost or expense in connection with such extensions, renewals, substitutions or replacements, and that such renewal or refunding Lien must be limited to all or any part of the same property and improvements, shares of stock or Indebtedness that secured the Lien that was renewed or refunded; or
- any Lien not permitted above securing Indebtedness that, together with the aggregate outstanding principal amount of other secured Indebtedness that would otherwise be subject to the above restrictions, excluding Indebtedness secured by Liens permitted under the above exceptions, and the Attributable Debt in respect of all Sale and Leaseback Transactions, not including Attributable Debt in respect of any such Sale and Leaseback Transactions described in the last two bullet points in the following paragraph, would not then exceed 15% of our Consolidated Net Tangible Assets.

Limitation on Sale and Leaseback Transactions. We covenant in the indenture that we will not, and will not permit any Restricted Subsidiary to, enter into any Sale and Leaseback Transaction unless:

- we or a Restricted Subsidiary would be entitled, without securing the Outstanding Securities of any series, to incur Indebtedness secured by a Lien on the Principal Property that is the subject of such Sale and Leaseback Transaction pursuant to the provisions described in the preceding paragraph;
- the Attributable Debt associated with the Sale and Leaseback Transaction would be in an amount permitted under the last bullet point of the preceding paragraph;
- the proceeds received in respect of the Principal Property so sold and leased back at the time of entering into such Sale and Leaseback Transaction are to be used for our business and operations or the business and operations of any Subsidiary; or
- within 12 months after the sale or transfer, an amount equal to the proceeds received in respect of the Principal Property so sold and leased back at the time of entering into such Sale and Leaseback Transaction is applied to the prepayment, other than mandatory prepayment, of any Outstanding Securities or Funded Indebtedness that is owed by us or a Restricted Subsidiary, other than Funded Indebtedness that is held by us or any Restricted Subsidiary or our Funded Indebtedness that is subordinate in right of payment to any Outstanding Securities that are entitled to the benefit of this covenant.

Definitions. Following are definitions of some of the terms used in the covenants described above.

"Attributable Debt" means, as to any lease under which any person is at the time liable for rent, at any date as of which the amount thereof is to be determined, the total net amount of rent required to be paid by such person under such lease during the remaining term, excluding amounts required to be paid on account of maintenance and repairs, services, insurance, taxes, assessments, water rates and similar charges and contingent rents, discounted from the respective due dates thereof at the rate of interest (or Yield to Maturity, in the case of original issue discount securities) borne by the then Outstanding Securities, compounded monthly.

"Capital Stock" means any and all shares, interests, rights to purchase, warrants, options, participations or other equivalents of or interests, however designated, in stock issued by a corporation.

"Consolidated Net Tangible Assets" means the aggregate amount of assets, less applicable reserves and other properly deductible items, after deducting:

- all current liabilities, excluding any portion thereof constituting Funded Indebtedness; and
- all goodwill, trade names, trademarks, patents, unamortized debt discount and expense and other like intangibles,

all as set forth on our most recent consolidated balance sheet contained in our latest quarterly or annual report filed with the SEC under the Securities Exchange Act of 1934, as amended, and computed in accordance with generally accepted accounting principles.

"Funded Indebtedness" means, as applied to any person, all Indebtedness of such person maturing after, or renewable or extendible at the option of the person beyond, 12 months from the date of determination.

"Indebtedness" means obligations for money borrowed, evidenced by notes, bonds, debentures or other similar evidences of indebtedness.

"Lien" means any lien, mortgage, pledge, encumbrance, charge or security interest securing Indebtedness; provided, however, that the following types of transactions will not be considered, for purposes of this definition, to result in a Lien:

- any acquisition by us or any Restricted Subsidiary of any property or assets subject to any reservation or exception under the terms of which any vendor, lessor or assignor creates, reserves or excepts or has created, reserved or excepted an interest in oil, gas or any other mineral in place or the proceeds thereof;

- any conveyance or assignment whereby we or any Restricted Subsidiary conveys or assigns to any person or persons an interest in oil, gas or any other mineral in place or the proceeds thereof;
- any Lien upon any property or assets either owned or leased by us or a Restricted Subsidiary or in which we or any Restricted Subsidiary owns an interest that secures for the benefit of the person or persons paying the expenses of developing or conducting operations for the recovery, storage, transportation or sale of the mineral resources of the property or assets, or property or assets with which it is unitized, the payment to such person or persons of our proportionate part or the Restricted Subsidiary's proportionate part of such development or operating expenses;
- any lease classified as an operating lease under generally accepted accounting principles;
- any hedging arrangements entered into in the ordinary course of business, including any obligation to deliver any mineral, commodity or asset in connection therewith; or
- any guarantees that we make for the repayment of Indebtedness of any Subsidiary or guarantees by any Subsidiary of the repayment of Indebtedness of any entity.

"Non-Recourse Indebtedness" means, at any time, Indebtedness incurred after the date of the indenture by us or a Restricted Subsidiary in connection with the acquisition of property or assets by us or a Restricted Subsidiary or the financing of the construction of or improvements on property, whenever acquired, provided that, under the terms of this Indebtedness and under applicable law, the recourse at such time and thereafter of the lenders with respect to such Indebtedness is limited to the property or assets so acquired, or the construction or improvements, including Indebtedness as to which a performance or completion guarantee or similar undertaking was initially applicable to the Indebtedness or the related property or assets if the guarantee or similar undertaking has been satisfied and is no longer in effect. Indebtedness which is otherwise Non-Recourse Indebtedness will not lose its character as Non-Recourse Indebtedness because there is recourse to us, any Subsidiary of ours or any other person for (a) environmental or tax warranties and indemnities and such other representations, warranties, covenants and indemnities as are customarily required in such transactions or (b) indemnities for and liabilities arising from fraud, misrepresentation, misapplication or non-payment of rents, profits, insurance and condemnation proceeds and other sums actually received from secured assets to be paid to the lender, waste and mechanics' liens or similar matters.

"Principal Property" means any natural gas distribution property located in the United States, except any property that in the opinion of our board of directors is not of material importance to the total business conducted by us and our consolidated Subsidiaries.

"Restricted Subsidiary" means any Subsidiary the amount of Consolidated Net Tangible Assets of which constitutes more than 10% of the aggregate amount of Consolidated Net Tangible Assets of us and our Subsidiaries.

"Sale and Leaseback Transaction" means any arrangement with any person in which we or any Restricted Subsidiary leases any Principal Property that has been or is to be sold or transferred by us or the Restricted Subsidiary to that person, other than any such arrangement involving:

- a lease for a term, including renewals at the option of the lessee, of not more than three years or classified as an operating lease under generally accepted accounting principles;
- leases between us and a Restricted Subsidiary or between Restricted Subsidiaries; and
- leases of a Principal Property executed by the time of, or within 12 months after the latest of, the acquisition, the completion of construction or improvement, or the commencement of commercial operation, of the Principal Property, whichever is later.

"Subsidiary" of ours means:

- a corporation, a majority of whose Capital Stock with rights, under ordinary circumstances, to elect directors is owned, directly or indirectly, at the date of determination, by us, by one or more of our Subsidiaries or by us and one or more of our Subsidiaries; or
- any other person, other than a corporation, in which at the date of determination we, one or more of our Subsidiaries or we and one or more of our Subsidiaries, directly or indirectly, have at least a majority ownership and power to direct the policies, management and affairs of that person.

Consolidation, Merger or Sale of Assets. Under the terms of the indenture, we will be generally permitted to consolidate with or merge into another entity. We will also be permitted to sell or transfer our assets substantially as an entirety to another entity. However, we may not take any of these actions unless all of the following conditions are met:

- the resulting entity, or the person to which such assets will have been sold or transferred, must agree to be legally responsible for all our obligations relating to the debt securities and the indenture;
- the transaction must not cause a default or an Event of Default, or an event that with notice or lapse of time or both would become an Event of Default, as described below;
- the resulting entity, or the person to which such assets will have been sold or transferred, must be organized under the laws of the United States or one of the states or the District of Columbia; and
- we must deliver an officers' certificate and legal opinion to the trustee with respect to the transaction.

In the event that we engage in one of these transactions and comply with the conditions listed above, we would be discharged from all our obligations and covenants under the indenture and all obligations under the Outstanding Securities, with the successor corporation or person succeeding to our obligations and covenants.

In the event that we engage in one of these transactions, the indenture provides that, if any Principal Property or Restricted Securities would thereupon become subject to any Lien securing Indebtedness, then the debt securities, other than debt securities not entitled to the benefits of specified covenants, must be secured, as to such Principal Property or Restricted Securities, equally and ratably with (or prior to or, in the case of debt securities that are subordinated in right of payment to the Indebtedness secured by such Lien or in the case of other Indebtedness of ours that is subordinated to the debt securities, on a subordinated basis to such Lien securing) the Indebtedness or obligations that upon the occurrence of such transaction would become secured by the Lien, unless the Lien could be created under the indenture without equally and ratably securing the debt securities (or, in the case of debt securities that are subordinated in right of payment to the Indebtedness secured by such Lien, on a subordinated basis to such Lien).

Modification or Waiver

There are two types of changes that we can make to the indenture and the debt securities.

Changes Requiring Approval. With the consent of the holders of at least a majority in principal amount of all outstanding debt securities of each series affected (including any such approvals obtained in connection with a tender or exchange offer for outstanding debt securities), we may make any changes, additions or deletions to any provisions of the indenture applicable to the affected series, or modify the rights of the holders of the debt securities of the affected series. However, without the consent of each holder affected, we cannot:

- change the stated maturity of the principal of, any premium on, or any installment of interest on any debt security;
- reduce the principal amount of, any premium on, or the rate of interest on any debt security;
- change any of our obligations to pay Additional Amounts;

- reduce the amount of the principal that would be due and payable upon a declaration of acceleration of maturity following the default of a debt security whose principal amount payable at stated maturity may be more or less than its principal face amount at original issuance or an original issue discount security;
- adversely affect any right of repayment at the holder's option;
- change the place of payment of a debt security;
- impair the holder's right to sue for payment;
- adversely affect any right to convert or exchange a debt security;
- reduce the percentage in principal amount of the outstanding debt securities of a series, the consent of whose holders is required to modify or amend the indenture; or
- modify certain provisions of the indenture dealing with suits for enforcement of payment by the trustee or modification and waiver, except to increase any percentage of consents required to amend the indenture or for any waiver, or to modify the provisions of the indenture dealing with the unconditional right of the holders of the debt securities to receive principal, premium, if any, and interest.

Changes Not Requiring Approval. The second type of change does not require the consent of any holders of the debt securities. This type is limited to clarifications and certain other changes that would not adversely affect holders of the outstanding debt securities in any material respect. Additionally, we do not need any approval to make any change that affects only debt securities to be issued under the indenture after the changes take effect.

Further Details Concerning Voting. When taking a vote, we will use the following rules to decide how much principal amount to attribute to a debt security:

- for original issue discount securities, we will use the principal amount that would be due and payable on the voting date if the maturity of the debt securities were accelerated to that date because of a default; and
- for debt securities whose principal amount is not known (for example, because it is based on an index) we will use a special rule for that debt security described in the applicable prospectus supplement.

Debt securities will not be considered outstanding, and therefore not eligible to vote, if we have deposited or set aside in trust money for their payment or redemption. Debt securities will also not be eligible to vote if they have been fully defeased as described later under "Defeasance and Covenant Defeasance."

Book-entry and other indirect holders should consult their banks or brokers for information on how approval may be granted or denied if we seek to change the indenture or the debt securities or request a waiver.

Events of Default

Holders of debt securities will have special rights if an Event of Default occurs as to the debt securities of their series that is not cured, as described later in this subsection. Please refer to the applicable prospectus supplement for information about any changes to the Events of Default, including any addition of a provision providing event risk or similar protection.

What is an Event of Default? The term "Event of Default" as to the debt securities of a series means any of the following:

- we do not pay interest on a debt security of the series within 30 days of its due date;
- we do not pay the principal of or any premium, if any, on a debt security of the series at its maturity;

- we do not deposit any sinking fund payment when and as due by the terms of any debt securities requiring such payment;
- we remain in breach of a covenant or agreement in the indenture, other than a covenant or agreement not for the benefit of the series, for 60 days after we receive written notice stating that we are in breach from the trustee or the holders of at least 25 percent of the principal amount of the debt securities of the series;
- we or a Restricted Subsidiary is in default under any matured or accelerated agreement or instrument under which we have outstanding Indebtedness for borrowed money or guarantees, which individually is in excess of $25,000,000, and we have not cured any acceleration within 30 days after we receive notice of this default from the trustee or the holders of at least 25 percent of the principal amount of the debt securities of the series, unless prior to the entry of judgment for the trustee, we or the Restricted Subsidiary remedy the default or the default is waived by the holders of the indebtedness;
- we file for bankruptcy or other events of bankruptcy, insolvency or reorganization occur; or
- any other Event of Default provided for the benefit of debt securities of the series.

An Event of Default for a particular series of debt securities will not necessarily constitute an Event of Default for any other series of debt securities issued under the indenture.

The trustee may withhold notice to the holders of debt securities of a particular series of any default if it considers its withholding of notice to be in the interest of the holders of that series, except that the trustee may not withhold notice of a default in the payment of the principal of, any premium on, or the interest on the debt securities or in the payment of any sinking fund installment with respect to the debt securities.

Remedies if an Event of Default Occurs. If an event of default has occurred and is continuing, the trustee or the holders of at least 25 percent in principal amount of the debt securities of the affected series may declare the entire principal amount and all accrued interest of all the debt securities of that series to be due and immediately payable by notifying us, and the trustee, if the holders give notice, in writing. This is called a declaration of acceleration of maturity.

If the maturity of any series of debt securities is accelerated and a judgment for payment has not yet been obtained, the holders of a majority in principal amount of the debt securities of that series may cancel the acceleration if all events of default other than the non-payment of principal or interest on the debt securities of that series that have become due solely by a declaration of acceleration are cured or waived, and we deposit with the trustee a sufficient sum of money to pay:

- all overdue interest on outstanding debt securities of that series;
- all unpaid principal and any premium, if any, of any outstanding debt securities of that series that has become due otherwise than by a declaration of acceleration, and interest on the unpaid principal and any premium, if any;
- all interest on such overdue interest; and
- all amounts paid or advanced by the trustee for that series and reasonable compensation of the trustee.

Except in cases of default, where the trustee has some special duties, the trustee is not required to take any action under the indenture at the request of any holders unless the holders offer the trustee reasonable protection from expenses and liability. This is called an indemnity. If reasonable indemnity is provided, the holders of a majority in principal amount of the outstanding debt securities of the relevant series may direct the time, method and place of conducting any lawsuit or other formal legal action seeking any remedy available to the trustee. The trustee may refuse to follow those directions if the directions conflict with any law or the indenture or expose the trustee to personal liability. No delay or omission in exercising any right or remedy will be treated as a waiver of that right, remedy or Event of Default.

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Before a holder is allowed to bypass the trustee and bring his or her own lawsuit or other formal legal action or take other steps to enforce his or her rights or protect his or her interest relating to the debt securities, the following must occur:

- the holder must give the trustee written notice that an Event of Default has occurred and remains uncured;
- the holders of at least 25 percent in principal amount of all outstanding debt securities of the relevant series must make a written request that the trustee take action because of the default and must offer reasonable indemnity to the trustee against the cost and other liabilities of taking that action;
- the trustee must not have instituted a proceeding for 60 days after receipt of the above notice and offer of indemnity; and
- the holders of a majority in principal amount of the debt securities must not have given the trustee a direction inconsistent with the above notice during the 60-day period.

However, a holder is entitled at any time to bring a lawsuit for the payment of money due on his or her debt securities on or after the due date without complying with the foregoing.

Holders of a majority in principal amount of the debt securities of the affected series may waive any past defaults other than the following:

- the payment of principal, any premium, or interest on any debt security; or
- in respect of a covenant that under the indenture cannot be modified or amended without the consent of each holder affected.

Each year, we will furnish the trustee with a written statement of two of our officers certifying that, to their knowledge, we are in compliance with the indenture and the debt securities, or else specifying any default.

Book-entry and other indirect holders should consult their banks or brokers for information on how to give notice or direction to or make a request of the trustee and how to declare or cancel an acceleration.

Defeasance and Covenant Defeasance

Unless we provide otherwise in the applicable prospectus supplement, the provisions for full defeasance and covenant defeasance described below apply to each series of debt securities. In general, we expect these provisions to apply to each debt security that is not a floating rate or indexed debt security.

Full Defeasance. If there is a change in U.S. federal tax law, as described below, we can legally release ourselves from all payment and other obligations on the debt securities, called “full defeasance,” if we put in place the following arrangements for you to be repaid:

- we must deposit in trust for the benefit of all holders of the debt securities a combination of money and obligations issued or guaranteed by the U.S. government that will generate enough cash to make interest, principal and any other payments on the debt securities on their various due dates; and
- we must deliver to the trustee a legal opinion confirming that there has been a change in current federal tax law or an IRS ruling that lets us make the above deposit without causing you to be taxed on the debt securities any differently than if we did not make the deposit and just repaid the debt securities ourselves at maturity.

If we ever did accomplish defeasance, as described above, you would have to rely solely on the trust deposit for repayment of the debt securities. You could not look to us for repayment in the event of any shortfall. Conversely, the trust deposit would most likely be protected from claims of our lenders and other creditors if we

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ever become bankrupt or insolvent. If we accomplish a defeasance, we would retain only the obligations to register the transfer or exchange of the debt securities, to maintain an office or agency in respect of the debt securities and to hold moneys for payment in trust.

Covenant Defeasance. Under current federal tax law, we can make the same type of deposit described above and be released from any restrictive covenants in the indenture. This is called "covenant defeasance." In that event, you would lose the protection of any such covenants but would gain the protection of having money and obligations issued or guaranteed by the U.S. government set aside in trust to repay the debt securities. In order to achieve covenant defeasance, we must do the following:

- deposit in trust for your benefit and the benefit of all other direct holders of the debt securities a combination of money and obligations issued or guaranteed by the U.S. government that will generate enough cash to make interest, principal and any other payments on the debt securities on their various due dates; and
- deliver to the trustee a legal opinion of our counsel confirming that, under current federal income tax law, we may make the deposit described above without causing you to be taxed on the debt securities any differently than if we did not make the deposit and just repaid the debt securities ourselves at maturity.

If we accomplish covenant defeasance, you can still look to us for repayment of the debt securities if there were a shortfall in the trust deposit or the trustee is prevented from making payment. In fact, if one of the remaining Events of Default occurred, such as our bankruptcy, and the debt securities became immediately due and payable, there may be a shortfall. Depending on the event causing the default, you may not be able to obtain payment of the shortfall.

Debt Securities Issued in Non-Global Form

If any debt securities cease to be issued in global form, they will be issued:

- only in fully registered form;
- without interest coupons; and
- unless we indicate otherwise in the prospectus supplement, in denominations of $2,000 and amounts that are integral multiples of $1,000 in excess thereof.

Holders may exchange their debt securities that are not in global form for debt securities of smaller denominations or combined into fewer debt securities of larger denominations, as long as the total principal amount is not changed.

Holders may exchange or transfer their debt securities at the office of the trustee. We may appoint the trustee to act as our agent for registering debt securities in the names of holders transferring debt securities, or we may appoint another entity to perform these functions or perform them ourselves.

Holders will not be required to pay a service charge to transfer or exchange their debt securities, but they may be required to pay for any tax or other governmental charge associated with the transfer or exchange. The transfer or exchange will be made only if our transfer agent is satisfied with the holder's proof of legal ownership.

If we have designated additional transfer agents for a holder's debt security, they will be named in the applicable prospectus supplement. We may appoint additional transfer agents or cancel the appointment of any particular transfer agent. We may also approve a change in the office through which any transfer agent acts.

If any debt securities are redeemable and we redeem less than all those debt securities, we may stop the transfer or exchange of those debt securities during the period beginning 15 days before the day we mail the notice of redemption and ending on the day of that mailing, in order to freeze the list of holders to prepare the mailing. We may also refuse to register transfers or exchanges of any debt securities selected for redemption, except that we will continue to permit transfers and exchanges of the unredeemed portion of any debt security that will be partially redeemed.

If a debt security is issued as a global security, only the depository will be entitled to transfer and exchange the debt security as described in this section, since it will be the sole holder of the debt security.

Payment Mechanics

Who Receives Payment? If interest is due on a debt security on an interest payment date, we will pay the interest to the person or entity in whose name the debt security is registered at the close of business on the regular record date, discussed below, relating to the interest payment date. If interest is due at maturity but on a day that is not an interest payment date, we will pay the interest to the person or entity entitled to receive the principal of the debt security. If principal or another amount besides interest is due on a debt security at maturity, we will pay the amount to the holder of the debt security against surrender of the debt security at a proper place of payment, or, in the case of a global security, in accordance with the applicable policies of the depository.

Payments on Global Securities. We will make payments on a global security in accordance with the applicable policies of the depository as in effect from time to time. Under those policies, we will pay directly to the depository, or its nominee, and not to any indirect holders who own beneficial interests in the global security. An indirect holder's right to those payments will be governed by the rules and practices of the depository and its participants, as described above under "What is a Global Security?".

Payments on Non-Global Securities. For a debt security in non-global form, we will pay interest that is due on an interest payment date by check mailed on the interest payment date to the holder at his or her address shown on the trustee's records as of the close of business on the regular record date. We will make all other payments by check, at the paying agent described below, against surrender of the debt security. We will make all payments by check in next-day funds; for example, funds that become available on the day after the check is cashed.

Alternatively, if a non-global security has a face amount of at least $1,000,000 and the holder asks us to do so, we will pay any amount that becomes due on the debt security by wire transfer of immediately available funds to an account at a bank in New York City on the due date. To request wire payment, the holder must give the paying agent appropriate transfer instructions at least five business days before the requested wire payment is due. In the case of any interest payment due on an interest payment date, the instructions must be given by the person who is the holder on the relevant regular record date. In the case of any other payment, we will make payment only after the debt security is surrendered to the paying agent. Any wire instructions, once properly given, will remain in effect unless and until new instructions are given in the manner described above.

Regular Record Dates. We will pay interest to the holders listed in the trustee's records as the owners of the debt securities at the close of business on a particular day in advance of each interest payment date. We will pay interest to these holders if they are listed as the owner even if they no longer own the debt security on the interest payment date. That particular day, usually about two weeks in advance of the interest payment date, is called the "regular record date" and will be identified in the prospectus supplement.

Payment When Offices Are Closed. If any payment is due on a debt security on a day that is not a business day, we will make the payment on the next business day. Payments postponed to the next business day in this situation will be treated under the indenture as if they were made on the original due date. A postponement of this kind will not result in a default under any debt security or the indenture, and no interest will accrue on the postponed amount from the original due date to the next business day.

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Paying Agents. We may appoint one or more financial institutions to act as our paying agents, at whose designated offices debt securities in non-global form may be surrendered for payment at their maturity. We call each of those offices a paying agent. We may add, replace or terminate paying agents from time to time. We may also choose to act as our own paying agent. Initially, we have appointed the trustee, at its corporate trust office in New York City, as the paying agent. We must notify you of changes in the paying agents.

Book-entry and other indirect holders should consult their banks or brokers for information on how they will receive payments on their debt securities.

The Trustee Under the Indenture

U.S. Bank National Association is the trustee under the indenture for our debt securities. We will identify any other entity acting as the trustee for a series of debt securities that we may offer in the prospectus supplement for the offering of such debt securities.

The trustee may resign or be removed with respect to one or more series of debt securities and a successor trustee may be appointed to act with respect to these series.

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DESCRIPTION OF COMMON STOCK

General

Our authorized capital stock consists of 200,000,000 shares of common stock, no par value, of which 111,352,650 shares were outstanding on November 8, 2018. Each of our shares of common stock is entitled to one vote on all matters voted upon by shareholders. Our shareholders do not have cumulative voting rights. Our issued and outstanding shares of common stock are fully paid and nonassessable. There are no redemption or sinking fund provisions applicable to the shares of our common stock, and such shares are not entitled to any preemptive rights. Since we are incorporated in both Texas and Virginia, we must comply with the laws of both states when issuing shares of our common stock.

Holders of our shares of common stock are entitled to receive such dividends as may be declared from time to time by our board of directors from our assets legally available for the payment of dividends and, upon our liquidation, a pro rata share of all of our assets available for distribution to our shareholders.

American Stock Transfer & Trust Company is the registrar and transfer agent for our common stock.

Charter and Bylaws Provisions

Some provisions of our articles of incorporation and bylaws may be deemed to have an "anti-takeover" effect. The following description of these provisions is only a summary, and we refer you to our articles of incorporation and bylaws for more information. Our articles of incorporation and bylaws are included as exhibits to our annual reports on Form 10-K filed with the SEC. See "Where You Can Find More Information."

Cumulative Voting. Our articles of incorporation prohibit cumulative voting. In general, in the absence of cumulative voting, one or more persons who hold a majority of our outstanding shares can elect all of the directors who are subject to election at any meeting of shareholders.

Removal of Directors. Our articles of incorporation and bylaws also provide that our directors may be removed only for cause and upon the affirmative vote of the holders of at least 75 percent of the shares then entitled to vote at an election of directors.

Fair Price Provisions. Article VII of our articles of incorporation provides certain "Fair Price Provisions" for our shareholders. Under Article VII, a merger, consolidation, sale of assets, share exchange, recapitalization or other similar transaction, between us or a company controlled by or under common control with us and any individual, corporation or other entity which owns or controls 10 percent or more of our voting capital stock, would be required to satisfy the condition that the aggregate consideration per share to be received in the transaction for each class of our voting capital stock be at least equal to the highest per share price, or equivalent price for any different classes or series of stock, paid by the 10 percent shareholder in acquiring any of its holdings of our stock. If a proposed transaction with a 10 percent shareholder does not meet this condition, then the transaction must be approved by the holders of at least 75 percent of the outstanding shares of voting capital stock held by our shareholders other than the 10 percent shareholder, unless a majority of the directors who were members of our board immediately prior to the time the 10 percent shareholder involved in the proposed transaction became a 10 percent shareholder have either:

- expressly approved in advance the acquisition of the outstanding shares of our voting capital stock that caused the 10 percent shareholder to become a 10 percent shareholder; or
- approved the transaction either in advance of or subsequent to the 10 percent shareholder becoming a 10 percent shareholder.

The provisions of Article VII may not be amended, altered, changed, or repealed except by the affirmative vote of at least 75 percent of the votes entitled to be cast thereon at a meeting of our shareholders duly called for

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consideration of such amendment, alteration, change, or repeal. In addition, if there is a 10 percent shareholder, such action must also be approved by the affirmative vote of at least 75 percent of the outstanding shares of our voting capital stock held by the shareholders other than the 10 percent shareholder.

Shareholder Proposals and Director Nominations. Our shareholders can submit shareholder proposals and nominate candidates for the board of directors if the shareholders follow the advance notice procedures described in our bylaws.

Shareholder proposals (other than those sought to be included in our proxy statement) must be submitted to our corporate secretary at least 60 days, but not more than 85 days, before the annual meeting; provided, however, that if less than 75 days' notice or prior public disclosure of the date of the annual meeting is given or made to shareholders, notice by the shareholder to be timely must be received by our corporate secretary no later than the close of business on the 25th day following the day on which such notice of the date of the annual meeting was provided or such public disclosure was made. The notice must include a description of the proposal, the shareholder's name and address and the number of shares held, and all other information which would be required to be included in a proxy statement filed with the SEC if the shareholder were a participant in a solicitation subject to the SEC's proxy rules. To be included in our proxy statement for an annual meeting, our corporate secretary must receive the proposal at least 120 days prior to the anniversary of the date we mailed the proxy statement for the prior year's annual meeting.

To nominate directors, shareholders must submit a written notice to our corporate secretary at least 60 days, but not more than 85 days, before a scheduled meeting; provided, however, that if less than 75 days' notice or prior public disclosure of the date of the annual meeting is given or made to shareholders, such nomination shall have been received by our corporate secretary no later than the close of business on the 25th day following the day on which such notice of the date of the annual meeting was mailed or such public disclosure was made. The notice must include the name and address of the shareholder and of the shareholder's nominee, the number of shares held by the shareholder, a representation that the shareholder is a holder of record of common stock entitled to vote at the meeting, and that the shareholder intends to appear in person or by proxy to nominate the persons specified in the notice, a description of any arrangements between the shareholder and the shareholder's nominee, information about the shareholder's nominee required by the SEC and the written consent of the shareholder's nominee to serve as a director.

Shareholder proposals and director nominations that are late or that do not include all required information may be rejected. This could prevent shareholders from bringing certain matters before an annual or special meeting or making nominations for directors.

PLAN OF DISTRIBUTION

We may sell the securities offered by this prospectus and a prospectus supplement as follows:

- through agents;
- to or through underwriters;
- through dealers;
- directly by us to purchasers;
- in "at the market offerings," within the meaning of Rule 415(a)(4) of the Securities Act; or
- through a combination of any such methods of sale.

We, directly or through agents or dealers, may sell, and the underwriters may resell, the securities in one or more transactions, including:

- transactions on the New York Stock Exchange or any other organized market where the securities may be traded;

- in the over-the-counter market;
- in negotiated transactions; or
- through a combination of any such methods of sale.

The securities may be sold at a fixed price or prices which may be changed, at market prices prevailing at the time of sale, at prices related to such prevailing market prices or at negotiated prices.

We may designate underwriters or agents to solicit purchases of shares of our common stock for the period of their appointment and to sell securities on a continuing basis, including pursuant to “at-the-market offerings.” We will do so pursuant to the terms of a distribution agreement between us and the underwriters or agents. If we engage in at-the-market sales pursuant to a distribution agreement, we will issue and sell the shares to or through one or more underwriters or agents, which may act on an agency basis or on a principal basis. During the term of any such distribution agreement, we may sell shares on a daily basis in exchange transactions or otherwise as we agree with the underwriters or agents. The distribution agreement may provide that any shares of our common stock sold will be sold at prices related to the then prevailing market prices for our securities. Therefore, exact figures regarding net proceeds to us or commissions to be paid are impossible to determine and will be described in a prospectus supplement. The terms of each such distribution agreement will be set forth in more detail in a prospectus supplement to this prospectus. To the extent that any named underwriter or agent acts as principal pursuant to the terms of a distribution agreement, or if we offer to sell shares of our common stock through another broker dealer acting as underwriter, then such named underwriter may engage in certain transactions that stabilize, maintain or otherwise affect the price of our shares. We will describe any such activities in the prospectus supplement relating to the transaction. To the extent that any named broker dealer or agent acts as agent on a best efforts basis pursuant to the terms of a distribution agreement, such broker dealer or agent will not engage in any such stabilization transactions.

Agents designated by us from time to time may solicit offers to purchase the securities. We will name any such agent involved in the offer or sale of the securities and set forth any commissions payable by us to such agent in a prospectus supplement relating to any such offer and sale of securities. Unless otherwise indicated in the prospectus supplement, any such agent will be acting on a best efforts basis for the period of its appointment. Any such agent may be deemed to be an underwriter of the securities, as that term is defined in the Securities Act.

If underwriters are used in the sale of securities, securities will be acquired by the underwriters for their own account and may be resold from time to time in one or more transactions. Securities may be offered to the public either through underwriting syndicates represented by one or more managing underwriters or directly by one or more firms acting as underwriters. If an underwriter or underwriters are used in the sale of securities, we will execute an underwriting agreement with such underwriter or underwriters at the time an agreement for such sale is reached. We will set forth in the prospectus supplement the names of the specific managing underwriter or underwriters, as well as any other underwriters, and the terms of the transactions, including compensation of the underwriters and dealers. Such compensation may be in the form of discounts, concessions or commissions. Underwriters and others participating in any offering of securities may engage in transactions that stabilize, maintain or otherwise affect the price of such securities. We will describe any such activities in the prospectus supplement.

We may elect to list any class or series of securities on any exchange, but we are not currently obligated to do so. It is possible that one or more underwriters, if any, may make a market in a class or series of securities, but the underwriters will not be obligated to do so and may discontinue any market making at any time without notice. We cannot give any assurance as to the liquidity of the trading market for any of the securities we may offer.

If a dealer is used in the sale of the securities, we or an underwriter will sell such securities to the dealer, as principal. The dealer may then resell such securities to the public at varying prices to be determined by such

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dealer at the time of resale. The prospectus supplement will set forth the name of the dealer and the terms of the transactions.

We may directly solicit offers to purchase the securities, and we may sell directly to institutional investors or others. These persons may be deemed to be underwriters within the meaning of the Securities Act with respect to any resale of the securities. The prospectus supplement will describe the terms of any such sales, including the terms of any bidding, auction or other process, if used.

Agents, underwriters and dealers may be entitled under agreements which may be entered into with us to indemnification by us against specified liabilities, including liabilities under the Securities Act, or to contribution by us to payments they may be required to make in respect of such liabilities. The prospectus supplement will describe the terms and conditions of such indemnification or contribution. Some of the agents, underwriters or dealers, or their affiliates, may engage in transactions with or perform services for us and our subsidiaries in the ordinary course of their business.

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LEGAL MATTERS

Gibson, Dunn & Crutcher LLP and Hunton Andrews Kurth LLP, Richmond, Virginia, have each rendered an opinion with respect to the validity of the securities that may be offered under this prospectus. We filed these opinions as exhibits to the registration statement of which this prospectus is a part. If counsel for any underwriters passes on legal matters in connection with an offering made under this prospectus, we will name that counsel in the prospectus supplement relating to that offering.

EXPERTS

The consolidated financial statements of Atmos Energy appearing in our Annual Report (Form 10-K) for the fiscal year ended September 30, 2018 (including the schedule appearing therein), and the effectiveness of Atmos Energy's internal control over financial reporting as of September 30, 2018 have been audited by Ernst & Young LLP, independent registered public accounting firm, as set forth in their reports thereon, included therein, and incorporated herein by reference. Such consolidated financial statements are incorporated herein by reference in reliance upon such reports given on the authority of such firm as experts in accounting and auditing.

WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission under the Securities Exchange Act of 1934, as amended (the "Exchange Act").

The SEC maintains a website that contains reports, proxy statements and other information about issuers, like us, who file electronically with the SEC. The address of that site is *www.sec.gov* . Unless specifically listed below under "Incorporation of Certain Documents by Reference" the information contained on the SEC website is not incorporated by reference into this prospectus.

You can also inspect reports, proxy statements and other information about us at the offices of the New York Stock Exchange, Inc., 11 Wall Street, New York, New York 10005.

We have filed with the SEC a registration statement on Form S-3, of which this prospectus is a part, which registers the securities we are offering. The registration statement, including the attached exhibits and schedules, contains additional relevant information about us and the securities offered. The rules and regulations of the SEC allow us to omit certain information included in the registration statement from this prospectus.

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INCORPORATION OF CERTAIN DOCUMENTS BY REFERENCE

The SEC allows us to "incorporate by reference" information in this prospectus that we have filed with it. This means that we can disclose important information to you by referring you to another document filed separately with the SEC. The information incorporated by reference is considered to be part of this prospectus, except for any information that is superseded by information that is included directly in this prospectus or the applicable prospectus supplement relating to an offering of our securities.

We incorporate by reference into this prospectus the documents listed below and any future filings we make with the SEC under Sections 13(a), 13(c), 14 or 15(d) of the Exchange Act prior to the termination of our offering of securities. These additional documents include periodic reports, such as annual reports on Form 10-K and quarterly reports on Form 10-Q, and current reports on Form 8-K (other than information furnished under Items 2.02 and 7.01 or corresponding information furnished under Item 9.01 as an exhibit, which is deemed not to be incorporated by reference in this prospectus), as well as proxy statements (other than information identified in them as not incorporated by reference). You should review these filings as they may disclose a change in our business, prospects, financial condition or other affairs after the date of this prospectus.

This prospectus incorporates by reference the documents listed below that we have filed with the SEC but have not been included or delivered with this document:

- Our annual report on Form 10-K for the year ended September 30, 2018;
- The following pages and captioned text contained in our definitive proxy statement for the annual meeting of shareholders on February 7, 2018 and incorporated into our annual report on Form 10-K: pages 7 through 11 under the captions *"Corporate Governance and Other Board Matters — Independence of Directors"* and *"— Related Person Transactions;"* pages 14 through 17 under the captions *"Corporate Governance and Other Board Matters — Committees of the Board of Directors," "— Independence of Audit Committee Members, Financial Literacy and Audit Committee Financial Experts,"* and *"— Other Board and Board Committee Matters — Human Resources Committee Interlocks and Insider Participation;"* page 19 through 25 under the caption *"Proposal One — Election of Directors — Nominees for Director;"* pages 26 to 29 under the caption *"Director Compensation;"* pages 30 to 31 under the caption *"Beneficial Ownership of Common Stock;"* page 33 under the caption *"Proposal Two — Ratification of Appointment of Independent Registered Public Accounting Firm — Audit Committee Pre-Approval Policy;"* page 36 under the caption *"Human Resources Committee Report;"* pages 37 through 50 under the caption *"Compensation Discussion and Analysis;"* pages 51 to 52 under the caption *"Other Executive Compensation Matters — Compensation Risk Assessment;"* and pages 53 through 69 under the caption *"Named Executive Officer Compensation."*

These documents contain important information about us and our financial condition.

You may obtain a copy of any of these filings, or any of our future filings, from us without charge by requesting it in writing or by telephone at the following address or telephone number:

Atmos Energy Corporation
1800 Three Lincoln Centre
5430 LBJ Freeway
Dallas, Texas 75240
Attention: Jennifer Hills
(972) 934-9227

Our website is *www.atmosenergy.com;* any information on or connected to our website is not part of this prospectus.

$450,000,000

Atmos Energy Corporation

4.125% Senior Notes due 2049

PROSPECTUS SUPPLEMENT

Joint Book-Running Managers

BNP PARIBAS **CIBC Capital Markets** **Credit Agricole CIB** **Wells Fargo Securities**
Mizuho Securities **MUFG** **TD Securities**

Senior Co-Manager

Regions Securities LLC

Co-Managers

BB&T Capital Markets **The Williams Capital Group, L.P.**

February 25, 2019

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

APPLICATION OF ATMOS ENERGY	**)**	
	)	
CORPORATION FOR AN ADJUSTMENT	**)**	**Case No. 2018-00281**
	)	
OF RATES AND TARIFF MODIFICATIONS	**)**	

<u>RE BUTTAL TESTIMONY OF LAURA K. GILLHIM</u>

I. <u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Laura K. Gillham. My business address is 5430 LBJ Freeway, Suite 600, Dallas, Texas 75240.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Director of Accounting Services for Atmos Energy Corporation (hereinafter "Atmos Energy" or the "Company").

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY AND EXHIBITS IN THIS DOCKET?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to rebut the testimony of AG witness Mr. Lane Kollen regarding his recommendation to modify the Division 002 Shared Services Unit (SSU) and Division 091 Kentucky/Mid-States (DGO) composite factors, which affect rate base and operating expense allocations to the Kentucky rate division.

Q. PLEASE SUMMARIZE MR. KOLLEN'S RECOMMENDATION REGARDING CHANGES TO SSU AND DGO ALLOCATION FACTORS.

A. Mr. Kollen proposes to eliminate operation and maintenance expenses and number of customers from the Division 002 SSU and Division 091 DGO composite factor and replace them with total operating expenses (O&M, Taxes-Other, and Depreciation Expense). The resulting allocation factor would be equally weighted between gross direct property plant and equipment and total operating expenses.[1]

Q. HAS MR. KOLLEN RECENTLY TESTIFIED ON THE TOPIC OF THE COMPANY'S CAM AND ITS COMPOSITE ALLOCATION FACTORS?

A. Yes. In Kentucky Public Service Commission Case No. 2017-00349, Mr. Kollen made these same recommended changes to the Company's composite allocation factors.

Q. DID THE COMMISSION ORDER ANY CHANGES TO COMPANY'S COMPOSITE ALLOCATION FACTORS AS A RESULT OF MR. KOLLEN'S RECOMMENDATIONS IN CASE NO. 2017-00349?

A. Although the challenge to the Company's allocation factors was not directly addressed in the final order, no adjustment was made to O&M expenses to reflect Mr. Kollen's proposed changes.

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[1] Kollen Direct at 50.

Q. DOES MR. KOLLEN MAKE ANY NEW ARGUMENTS IN THIS CASE?

A. No.

Q. HOW DID THE COMPANY DETERMINE THE COMPOSITE FACTORS USED IN THIS CASE?

A. The Company describes how the composite factors are determined in the Cost Allocation Manual (CAM) that was filed as exhibit LKG-1 attached to my pre-filed testimony. It is the same method as was used in Case No. 2017-00349.

Q. PLEASE DESCRIBE THE HISTORY OF THE CAM.

A. Although the Company had been utilizing the allocation methodology described in the CAM for many years prior, the CAM was formally documented in response to 807 K.A.R. 5 :080, and was first filed with the Commission in April of 2001. Atmos Energy is required to update the CAM each year. The Company has used the CAM to document its allocation processes in the regular course of business since it was first filed with the Commission.

Q. WHAT ARE THE FUNCTIONS OF SHARED SERVICES (SSU) AND THE KENTUCKY MID-STATES DIVISION GENERAL OFFICE (DGO)?

A. The Company's Shared Services Unit (SSU) consists of functions that serve multiple rate divisions. These services include departments such as legal, billing, call center, accounting, information technology, human resources, gas supply, and rates administration, among others. SSU is comprised of SSU - General Office (Division 002) and SSU - Customer Support. SSU - General Office includes all other functions not encompassed by SSU - Customer Support. SSU - Customer Support includes billing, customer call center functions and customer support related services. The Kentucky Mid-States General Office (DGO) is an administrative office that is located outside of SSU which serve as the base of operations and central office for the operating division that encompasses the Company's operations in Kentucky, Tennessee and Virginia.

Q. HOW ARE SSU AND DGO EXPENSES ALLOCATED TO KENTUCKY?

A. SSU - General Office department expenses are allocated by department to the applicable operating divisions using the Composite Factor. The DGO's charges are allocated to the rate divisions using the composite rate for each rate division. Costs are allocated to operating divisions based on a composite factor applied to the SSU departments.

The Composite Factor is the simple average of three percentages:

(1) The average percentage of gross direct property plant and equipment in each operating division unit as a percentage of the total direct property plant and equipment in all of the operating divisions.

(2) The average number of customers in each operating division as a percentage of the total number of customers in all of the operating divisions.

(3) The total direct O&M expense in each operating division as a percentage of the total direct O&M expense in all operating divisions.

SSU - Customer Service department expenses are allocated by cost center to the applicable operating division based on the average number of customers in each operating division as a percentage of the total number of customers in all of the operating divisions. The DGO charges are allocated to rate divisions based on the number of customers in the rate division.

DGO department expenses, which are incurred directly in the DGO, are allocated to the rate divisions utilizing the composite rate for each rate division. The calculations for factors used in this filing for both SSU and DGO were provided in the Company's response to Staff Set 1, Item 71.

Q. HAS THE COMPANY APPLIED ITS ALLOCATION METHODOLOGY CONSISTENTLY, OBJECTIVELY, AND IN ACCORDANCE WITH ITS COST ALLOCATION MANUAL SINCE THE INITIAL INCEPTION OF THE COST ALLOCATION MANUAL, INCLUDING IN CASE NO. 2017-00349 THAT WAS HEARD BEFORE THE KENTUCKY PUBLIC SERICE COMMISSION?

A. Yes. Although the percentages change each year with the input of the latest available fiscal year information, the methodology underlying calculation of the composite factors is the same, as it has been even before developing the CAM in April 2001.

Q. DO YOU AGREE WITH MR. KOLLEN THAT THE COMPOSITE FACTORS USED FOR DIVISION 002 AND DIVISION 091 ARE NOT REASONABLE?[2]

A. No. Atmos Energy's allocation methodology is reasonable and reflective of cost causation. It is applied in all of the jurisdictions in which Atmos Energy operates in a manner that is uniform and consistent and ensures full and fair allocation of Division 002 and Division 091 costs. The cost allocations that result from the

[2] Kollen Direct at 49.

composite factors yield fairly and justly apportioned costs in compliance with KRS 278.010 (20).

Q. WHAT ARE MR. KOLLEN'S RECOMMENDATIONS FOR COMPOSITE FACTORS?

A. He agrees that the gross direct property plant and equipment is reasonable. He claims that the number of customers is not reasonable because there is a separate customer allocation factor that is used for customer costs, particularly the costs from Division 012 Call Center customer support.[3] He also claims that total direct O&M is not reasonable because it is not a comprehensive measure of all expenses that are managed by Division 002.[4]

Q. DO YOU AGREE WITH HIS RECOMMENDATION THAT THE NUMBER OF CUSTOMERS IS NOT REASONABLE?

A. No. It is important to the Company to develop a reasonable correlation between cost causation and allocation of common corporate costs. Servicing our customer needs requires significant management effort. As alluded to above, division 002 includes all other functions not encompassed by division 012. These costs include, among others, senior management costs. The need for and the level of services provided by the Utility is principally driven by the number of customers serviced by a particular operating division. Inclusion of this factor in the composite factor ensures that common corporate costs are being assigned in reasonable relation to

[3] Kollen Direct at 49.
[4] Kollen Direct at 49.

the divisions that generate those costs by providing the necessary functions required to service customers.

Q. DO YOU AGREE WITH HIS RECOMMENDATION THAT TOTAL DIRECT O&M IS NOT REASONABLE?

A. No. Direct O&M is a better metric than total operating expenses as it better reflects the level of service provided. In the Company's extensive experience in providing local gas distribution utility service in multiple jurisdictions, the relative percentage of O&M direct expense appropriately reflects cost causation attributable to a particular division. That is, in allocating common costs for Atmos Energy, the level of O&M direct expense directly attributable to a particular division is one of the principle drivers of the level of services provided by rate division 002 and rate division 091. It has a high, and therefore reasonable, correlation with a division's use of common SSU and DGO services and should be utilized as a component of the three factor composite factor.

Q. WHY IS USING TOTAL OPERATING EXPENSES INAPPROPRIATE?

A. Using total operating expenses as a component of the composite factor produces circular results. As an example, suppose another division of the Company had total operating expense decreases, but the level of service provided to them remains the same. That would mean that the costs to the other divisions' operations would be reduced via the allocation process in the following year, which would again be incorporated into the allocation process making that division's operations less profitable. At no time during these hypothetical years would the costs have been representative of the actual level of service.

Q. WHY IS DIRECT O&M A BETTER INDICATOR OF COST CAUSATION THAN TOTAL OPERATING EXPENSES?

A. Direct O&M represents a collection of expenditure types such as labor, benefits, utilities, telecom and IT expenses that are directly related to the services provided to the operating divisions. In other words, it is the people, as well as their related benefits and employee driven costs, that provide the services to the operating divisions and whose costs must be allocated. Depreciation expense is directly related to and therefore redundant to gross plant, which Mr. Kollen agrees is already one of the reasonable factors that should be included in a composite factor. Depending on the rate structure of any particular jurisdiction relative to another, Other Taxes can easily distort the composite allocation. Texas, for example, requires regulated utilities to record revenue related taxes (such as franchise fees) as revenue and offsetting Other Tax expense. Including them in the composite factor calculation distorts the allocation away from jurisdictions that do not record such items on the income statement. In the cases of depreciation expense and Other Tax expense, to the extent they are higher or lower for a particular jurisdiction, they are not drivers of service costs. In both cases, they are managed by shared resources (primarily people) whose costs are accounted for as O&M and are properly allocated using the Company's existing allocation methodology.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY	**)**	
	)	
CORPORATION FOR AN ADJUSTMENT	**)**	**Case No. 2018-00281**
	)	
OF RATES AND TARIFF MODIFICATIONS	**)**	

REBUTTAL TESTIMONY OF JAMES H. VANDER WEIDE, PH.D.

INDEX TO THE REBUTTAL TESTIMONY
OF JAMES H. VANDER WEIDE, WITNESS FOR
ATMOS ENERGY CORPORATION

TABLE OF CONTENTS

Exhibits:

I. INTRODUCTION AND PURPOSE

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

A. My name is James H. Vander Weide. I am President of Financial Strategy Associates, a firm that provides strategic and financial consulting services to business clients. My business address is 3606 Stoneybrook Drive, Durham, North Carolina 27705.

Q. ARE YOU THE SAME JAMES H. VANDER WEIDE WHO PREVIOUSLY PRESENTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I have been asked by Atmos Energy to respond to the direct testimony and exhibits of Mr. Lane Kollen with respect to his recommendation that Atmos Energy be allowed to earn a rate of return on equity equal to 9.7 percent. Mr. Kollen testifies on behalf of the Office of Attorney General.

Q. WHAT COST OF EQUITY DO YOU RECOMMEND FOR ATMOS ENERGY IN THIS PROCEEDING?

A. I recommended a cost of equity equal to 10.4 percent.

Q. HOW DID YOU ARRIVE AT YOUR 10.4 PERCENT ESTIMATE OF ATMOS ENERGY'S COST OF EQUITY?

A. As described in my direct testimony, I arrived at my 10.4 percent estimate of Atmos Energy's cost of equity by applying standard cost of equity estimation methods, including the discounted cash flow ("DCF"), risk premium, and capital asset pricing model ("CAPM") to a proxy group of publicly-traded natural gas utilities of comparable risk.

Q. ARE THE DCF, RISK PREMIUM, AND CAPM COST OF EQUITY METHODS FREQUENTLY USED TO ESTIMATE THE COST OF EQUITY FOR REGULATED UTILITIES?

A. Yes. From my years of experience in estimating the cost of equity for regulated utilities, I have found that company, staff, and consumer expert witnesses frequently rely on multiple cost of equity methods, including the DCF, risk premium, and CAPM, to estimate a utility's cost of equity in regulatory proceedings.

Q. WHAT AVERAGE COST OF EQUITY RESULT DID YOU OBTAIN FROM YOUR APPLICATION OF YOUR COST OF EQUITY METHODS USING MARKET DATA FOR THE THREE-MONTH PERIOD ENDING JULY 31, 2018?

A. As shown in my direct testimony, Table 2, page 46, the average result of my application of my cost of equity methods to my proxy group of publicly-traded natural gas utilities using data for the three-month period ending July 31, 2018, is 10.4 percent.

II. REBUTTAL COMMENTS

Q. HOW DOES MR. KOLLEN ARRIVE AT HIS RECOMMENDED 9.7 PERCENT ALLOWED RATE OF RETURN ON EQUITY FOR ATMOS ENERGY?

A. Mr. Kollen simply accepts the 9.7 percent allowed rate of return on equity ("ROE") that the Public Service Commission of Kentucky ("PSC" or "Commission") approved for Atmos Energy in Case No. 2017-00349.

Q. DOES MR. KOLLEN PROVIDE ANY EVIDENCE TO SUPPORT HIS RECOMMENDATION TO APPLY THE 9.7 PERCENT PSC-APPROVED ROE IN CASE NO. 2017-00349 TO ATMOS ENERGY IN THIS PROCEEDING, CASE NO. 2018-00281?

A. No.

Q. YOU NOTE THAT MR. KOLLEN RECOMMENDS THAT THE PSC ADOPT THE SAME ROE IN THIS CASE AS IT HAD ADOPTED IN CASE NO. 2017-00349. WHAT COST OF EQUITY EVIDENCE DID THE PSC REVIEW TO ARRIVE AT ITS 9.7 PERCENT ROE IN THE 2017 CASE?

A. The PSC reviewed the testimonies filed in Case No. 2017-00349, including my direct and rebuttal testimonies, filed in September 2017 and February 2018, and the testimony of Mr. Baudino filed in January 2018.

Q. DID THE PSC EXPLAIN HOW IT ARRIVED AT THE 9.7 PERCENT ROE IT APPROVED IN CASE NO. 2017-00349?

A. Although the PSC does not explain precisely how it arrived at the 9.7 percent ROE it approved, the PSC does present some of its opinions regarding evidence that had been presented in the 2017 proceeding, namely:

1. Flotation costs "should be excluded from the analysis as they are already accounted for in the current stock prices." (Order at page 28)

2. South Jersey Industries should be excluded from the DCF proxy group because "including South Jersey as a proxy company in the DCF model results in an overstated ROE." (Order at page 28)

3. The average authorized ROE in the gas utility industry in 2017 was 9.72 percent, and, absent an outlier, 9.63 percent. (Order at page 29)

4. The average earned ROE for Atmos Energy's proxy group is 9.23 percent. (Order at page 29)

5. The Commission recently awarded Duke Energy Kentucky an ROE equal to 9.725 percent. (Order at page 29)

6. The Commission "agrees with Atmos that one must not only look at other regulatory decisions but also at capital markets and expected returns from similar utilities." (Order at page 29)

Q. DO YOU AGREE WITH THE COMMISSION'S CONCLUSION THAT FLOTATION COSTS SHOULD NOT BE RECOVERED IN THE COST OF EQUITY BECAUSE THEY ARE ALREADY ACCOUNTED FOR IN CURRENT STOCK PRICES?

A. No. Flotation costs are an expense that is deducted from the proceeds associated with a stock issuance before the proceeds are distributed to the issuing company.

Because the stock price reflects the return on the amount of cash actually invested by the company, and flotation costs are deducted from the proceeds of a stock issuance prior to the distribution of the net proceeds to the company, flotation costs are not included in the stock price.

Q. IF FLOTATION COSTS ARE AN EXPENSE, WHY DO YOU INCLUDE THEM IN YOUR CALCULATION OF A COMPANY'S COST OF EQUITY?

A. I include flotation costs in my calculation of a company's cost of equity because the company will not be able to earn a fair return on equity if flotation costs are not included in the estimate of the cost of equity.

Q. CAN YOU ILLUSTRATE WHY A COMPANY WILL NOT BE ABLE TO EARN A FAIR RETURN ON EQUITY IF FLOTATION COSTS ARE NOT INCLUDED IN THE ESTIMATE OF THE COST OF EQUITY?

A. Yes. Assume that a company issues $100 in equity, incurs $3 in flotation costs, and that the investors' required rate of return on equity is 10 percent. To satisfy the investors' return requirement, the company must earn a $10 return on the $100 stock holders invest in the company. However, because of the flotation cost, the company will have only $97 to invest in rate base. Thus, the company must earn a 10.31 percent return on its $97 investment in order to earn the investors' required $10 return (10.31% x $97 = $10).

Q. DO YOU AGREE WITH THE COMMISSION'S STATEMENT IN ITS ORDER IN CASE NO. 2017-00349 THAT INCLUDING SOUTH JERSEY INDUSTRIES IN THE DCF MODEL RESULTS CAUSES AN OVER-STATED COST OF EQUITY ESTIMATE?

A. No. First, with regard to the cost of equity studies that I presented in my direct testimony in Case No. 2017-00349, I note that South Jersey Industries' DCF result was not significantly above the average result for my proxy group: the average DCF result for the proxy group was 9.35 percent (the average of the simple average and the market-weighted average result for the proxy group), compared to a result for South Jersey equal to 9.45 percent. Moreover, (due to the small market capitalization of South Jersey compared to others in the proxy group), eliminating South Jersey from the proxy group entirely changes the DCF result by just one basis point, from 9.35 percent to 9.34 percent.

More importantly, my cost of equity recommendation in the previous case, and in this case, does not depend on the application of a single cost of equity method. Rather, my recommendation depends on the application of multiple cost of equity models, including the DCF, risk premium, and CAPM.

Q. THE COMMISSION'S ORDER IN THE 2017 PROCEEDING CITES AN AVERAGE 9.23 PERCENT EARNED ROE FOR THE NATURAL GAS UTILITY PROXY GROUP AS SUPPORT FOR ITS DECISION TO SET ATMOS ENERGY'S ALLOWED ROE EQUAL TO 9.7 PERCENT. HOW DID THE COMMISSION ARRIVE AT THE 9.23 PERCENT EARNED ROE IT CITED IN ITS ORDER IN THE PREVIOUS PROCEEDING?

A. In the 2017 case, the Staff in data request 2-48 requested information on the most recent earned ROEs for the proxy natural gas utility group. The data provided in response to that request are for the year 2016, which was the most recent available data at that time, reported in the December 1, 2017 Value Line natural gas utility reports.

Q. WHAT ARE THE AVERAGE EARNED AND EXPECTED ROES FOR THE VALUE LINE NATURAL GAS UTILITIES FOR THE YEARS 2018 AND 2022 - 2024?

A. The average earned ROE for the Value Line natural gas utilities is equal to 10.4 percent in 2018, and the average expected ROE for 2022 - 2024 is 10.6 percent (see Table 1 below, which displays data from the March 1, 2019 Value Line reports for the natural gas utilities).

Table 1
Earned and Expected Returns on Equity
for the Value Line Natural Gas Utilities

	Company	2018	2022-2024
1	Atmos Energy	9.3%	10.0%
2	Chesapeake Utilities	10.0%	10.0%
3	New Jersey Resources	17.1%	11.0%
4	NiSource Inc.	8.0%	9.0%
5	Northwest Nat. Gas	8.5%	12.0%
6	ONE Gas Inc.	8.5%	10.0%
7	South Jersey Inds.	10.5%	12.0%
8	Southwest Gas	9.0%	9.5%
9	Spire Inc.	9.5%	10.5%
10	UGI Corp.	13.2%	11.5%
11	Average	10.4%	10.6%

Q. DO VALUE LINE'S REPORTED AVERAGE EARNED AND EXPECTED ROES IN THE RANGE 10.4 PERCENT TO 10.6 PERCENT SUPPORT MR. KOLLEN'S RECOMMENDATION TO SET ATMOS ENERGY'S ALLOWED ROE IN THIS PROCEEDING TO 9.7 PERCENT?

A. No. To the contrary, these data support the conclusion that Mr. Kollen's recommended ROE is too low and that my recommendation to set Atmos Energy's allowed ROE equal to 10.4 percent is reasonable.

Q. THE COMMISSION CONCLUDED IN THE 2017 CASE THAT THEY SHOULD "LOOK NOT ONLY AT OTHER REGULATORY DECISIONS BUT ALSO AT CAPITAL MARKETS AND EXPECTED RETURNS FROM OTHER SIMILAR RISK UTILITIES." (ORDER AT 29). DO CURRENT CAPITAL MARKET DATA AND EXPECTED RETURNS FOR SIMILAR-RISK UTILITIES SUPPORT MR. KOLLEN'S RECOMMENDED 9.7 PERCENT ROE?

A. No. As shown above in Table 1, actual and expected returns for other similar-risk utilities, the Value Line natural gas utilities, support a return on equity in the range 10.4 percent to 10.6 percent. The capital market studies reported in my direct testimony support a cost of equity of 10.4 percent. As I show below, my updated capital market cost of equity studies support a cost of equity of 10.5 percent.

III. UPDATED COST OF EQUITY STUDIES

Q. HOW DO YOU ESTIMATE ATMOS ENERGY'S COST OF EQUITY IN YOUR DIRECT TESTIMONY?

A. In my direct testimony, I estimate Atmos Energy's cost of equity by applying standard cost of equity methods, including the DCF, the ex ante risk premium method, the ex post risk premium method, and the CAPM to market data for the Value Line natural gas utilities. A complete description of these methods and my application of these methods is found in my direct testimony.

Q. HAVE YOU UPDATED YOUR STUDY OF ATMOS ENERGY'S COST OF EQUITY USING MORE RECENT DATA?

A. Yes.

Q. WHAT RESULTS DO YOU OBTAIN FROM YOUR UPDATED STUDIES OF ATMOS ENERGY'S COST OF EQUITY?

A. The average result of my updated cost of equity studies for my proxy group of publicly-traded natural gas distribution utilities is 10.5 percent (see Table 2 below). Exhibits showing the detailed results of my updated studies accompany my testimony, Rebuttal Schedules 1 through 9.

Table 2
Cost of Equity Model Results

Method	Model Result
DCF	9.6%
Ex Ante Risk Premium	10.8%
Ex Post Risk Premium	10.1%
CAPM-Historical	9.6%
CAPM-DCF Based	12.2%
Average	10.5%

Q. WHAT CONCLUSION DO YOU DRAW FROM YOUR UPDATED STUDIES OF ATMOS ENERGY'S COST OF EQUITY?

A. I conclude that my updated cost of equity studies continue to support my recommended 10.4 percent allowed rate of return on equity for Atmos Energy in this proceeding.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

LIST OF REBUTTAL SCHEDULES

ATMOS ENERGY
EXHIBIT__(JVW-1)
REBUTTAL SCHEDULE 1
SUMMARY OF DISCOUNTED CASH FLOW ANALYSIS
FOR NATURAL GAS UTILITIES

	COMPANY	MOST RECENT QUARTERLY DIVIDEND (d_0)	STOCK PRICE (P_0)	FORECAST OF FUTURE EARNINGS GROWTH	MARKET CAP $ (MIL)	DCF MODEL RESULT
1	Atmos Energy	0.525	94.947	6.5%	11,116	8.9%
2	Chesapeake Utilities	0.370	84.475	7.9%	1,380	9.9%
3	New Jersey Resources	0.293	47.257	3.9%	4,286	6.6%
4	NiSource Inc.	0.195	25.674	7.2%	9,547	10.8%
5	Northwest Nat. Gas	0.475	66.172	8.2%	1,823	11.5%
6	ONE Gas Inc.	0.460	81.787	7.4%	4,354	10.0%
7	South Jersey Inds.	0.288	31.087	10.9%	2,516	15.4%
8	Southwest Gas	0.520	79.733	7.2%	4,197	10.2%
9	Spire Inc.	0.593	75.068	3.2%	3,846	6.6%
10	UGI Corp.	0.260	55.007	6.0%	9,694	8.1%
11	Average					9.8%
12	Market-weighted Average					9.4%
13	Average, simple, market-weighted					9.6%
14	Average excluding highest and lowest					9.5%

Notes:

d_0	=	Most recent quarterly dividend
d_1,d_2,d_3,d_4	=	Next four quarterly dividends, calculated by multiplying the last four quarterly dividends by the factor (1 + g)
P_0	=	Average of the monthly high and low stock prices during the three months ending December 2018 per Refinitiv (formerly known as Thomson Reuters[1]
FC	=	Flotation cost allowance (five percent) as a percent of stock price
g	=	Forecast of future earnings growth December 2018 from Refinitiv (formerly Thomson Reuters), Value Line, and Yahoo Finance
k	=	Cost of equity using the quarterly version of the DCF model

$$k = \frac{d_1(1+k)^{.75} + d_2(1+k)^{.50} + d_3(1+k)^{.25} + d_4}{P_0(1-FC)} + g$$

[1] In my rebuttal DCF analysis, I obtain earnings growth forecasts from Value Line and Yahoo Finance in addition to IBES/Refinitiv in order to have sufficient data to include all the Value Line natural gas utilities in the DCF analysis. I calculate the Value Line EPS growth forecasts using Value Line's EPS estimate for 2018 as the beginning period and its EPS estimate for the period 2021 – 2023 as the ending period, using the formula (EPS 2021-2023/EPS2018)$^{.25}$ -1 (data are from the November 30, 2018 Value Line gas utility reports). For example, the Value Line EPS 2018 forecast for Atmos is \$4.00, and for the period 2021 -2023, \$5.15. Using these data, the EPS growth estimate is (5.15/4.00)$^{.25}$ -1 = 6.5%. (The IBES EPS growth forecast for Atmos is also 6.5 percent.)

ATMOS ENERGY
EXHIBIT__(JVW-1)
REBUTTAL SCHEDULE 2
COMPARISON OF DCF EXPECTED RETURN ON AN INVESTMENT IN NATURAL GAS UTILITY STOCKS TO THE INTEREST RATE ON MOODY'S A-RATED UTILITY BONDS

In this analysis, I compute a natural gas utility equity risk premium by comparing the DCF estimated cost of equity for an electric utility proxy group to the interest rate on A-rated utility bonds. For each month in my June 1998 through December 2018 study period:

DCF = Average DCF-estimated cost of equity on a portfolio of proxy companies;
Bond Yield = Yield to maturity on an investment in A-rated utility bonds; and
Risk Premium = DCF – Bond yield.

A more detailed description of my *ex ante* risk premium method is contained in Appendix 4.

LINE	DATE	DCF	BOND YIELD	RISK PREMIUM
1	Jun-98	0.1154	0.0703	0.0451
2	Jul-98	0.1186	0.0703	0.0483
3	Aug-98	0.1234	0.0700	0.0534
4	Sep-98	0.1273	0.0693	0.0580
5	Oct-98	0.1260	0.0696	0.0564
6	Nov-98	0.1211	0.0703	0.0508
7	Dec-98	0.1185	0.0691	0.0494
8	Jan-99	0.1195	0.0697	0.0498
9	Feb-99	0.1243	0.0709	0.0534
10	Mar-99	0.1257	0.0726	0.0531
11	Apr-99	0.1260	0.0722	0.0538
12	May-99	0.1221	0.0747	0.0474
13	Jun-99	0.1208	0.0774	0.0434
14	Jul-99	0.1222	0.0771	0.0451
15	Aug-99	0.1220	0.0791	0.0429
16	Sep-99	0.1226	0.0793	0.0433
17	Oct-99	0.1233	0.0806	0.0427
18	Nov-99	0.1240	0.0794	0.0446
19	Dec-99	0.1280	0.0814	0.0466
20	Jan-00	0.1301	0.0835	0.0466
21	Feb-00	0.1344	0.0825	0.0519
22	Mar-00	0.1344	0.0828	0.0516
23	Apr-00	0.1316	0.0829	0.0487
24	May-00	0.1292	0.0870	0.0422
25	Jun-00	0.1295	0.0836	0.0459
26	Jul-00	0.1317	0.0825	0.0492
27	Aug-00	0.1290	0.0813	0.0477
28	Sep-00	0.1257	0.0823	0.0434
29	Oct-00	0.1260	0.0814	0.0446
30	Nov-00	0.1251	0.0811	0.0440
31	Dec-00	0.1239	0.0784	0.0455
32	Jan-01	0.1261	0.0780	0.0481
33	Feb-01	0.1261	0.0774	0.0487
34	Mar-01	0.1275	0.0768	0.0507
35	Apr-01	0.1227	0.0794	0.0433
36	May-01	0.1302	0.0799	0.0503
37	Jun-01	0.1304	0.0785	0.0519
38	Jul-01	0.1338	0.0778	0.0560
39	Aug-01	0.1327	0.0759	0.0568

LINE	DATE	DCF	BOND YIELD	RISK PREMIUM
40	Sep-01	0.1268	0.0775	0.0493
41	Oct-01	0.1268	0.0763	0.0505
42	Nov-01	0.1268	0.0757	0.0511
43	Dec-01	0.1254	0.0783	0.0471
44	Jan-02	0.1236	0.0766	0.0470
45	Feb-02	0.1241	0.0754	0.0487
46	Mar-02	0.1189	0.0776	0.0413
47	Apr-02	0.1159	0.0757	0.0402
48	May-02	0.1162	0.0752	0.0410
49	Jun-02	0.1170	0.0741	0.0429
50	Jul-02	0.1242	0.0731	0.0511
51	Aug-02	0.1234	0.0717	0.0517
52	Sep-02	0.1260	0.0708	0.0552
53	Oct-02	0.1250	0.0723	0.0527
54	Nov-02	0.1221	0.0714	0.0507
55	Dec-02	0.1216	0.0707	0.0509
56	Jan-03	0.1219	0.0706	0.0513
57	Feb-03	0.1232	0.0693	0.0539
58	Mar-03	0.1195	0.0679	0.0516
59	Apr-03	0.1162	0.0664	0.0498
60	May-03	0.1126	0.0636	0.0490
61	Jun-03	0.1114	0.0621	0.0493
62	Jul-03	0.1127	0.0657	0.0470
63	Aug-03	0.1139	0.0678	0.0461
64	Sep-03	0.1127	0.0656	0.0471
65	Oct-03	0.1123	0.0643	0.0480
66	Nov-03	0.1089	0.0637	0.0452
67	Dec-03	0.1071	0.0627	0.0444
68	Jan-04	0.1059	0.0615	0.0444
69	Feb-04	0.1039	0.0615	0.0424
70	Mar-04	0.1037	0.0597	0.0440
71	Apr-04	0.1041	0.0635	0.0406
72	May-04	0.1045	0.0662	0.0383
73	Jun-04	0.1036	0.0646	0.0390
74	Jul-04	0.1011	0.0627	0.0384
75	Aug-04	0.1008	0.0614	0.0394
76	Sep-04	0.0976	0.0598	0.0378
77	Oct-04	0.0974	0.0594	0.0380
78	Nov-04	0.0962	0.0597	0.0365
79	Dec-04	0.0970	0.0592	0.0378
80	Jan-05	0.0990	0.0578	0.0412
81	Feb-05	0.0979	0.0561	0.0418
82	Mar-05	0.0979	0.0583	0.0396
83	Apr-05	0.0988	0.0564	0.0424
84	May-05	0.0981	0.0553	0.0427
85	Jun-05	0.0976	0.0540	0.0436
86	Jul-05	0.0966	0.0551	0.0415
87	Aug-05	0.0969	0.0550	0.0419
88	Sep-05	0.0980	0.0552	0.0428
89	Oct-05	0.0990	0.0579	0.0411
90	Nov-05	0.1049	0.0588	0.0461
91	Dec-05	0.1045	0.0580	0.0465
92	Jan-06	0.0982	0.0575	0.0407
93	Feb-06	0.1124	0.0582	0.0542
94	Mar-06	0.1127	0.0598	0.0529

LINE	DATE	DCF	BOND YIELD	RISK PREMIUM
95	Apr-06	0.1100	0.0629	0.0471
96	May-06	0.1056	0.0642	0.0414
97	Jun-06	0.1049	0.0640	0.0409
98	Jul-06	0.1087	0.0637	0.0450
99	Aug-06	0.1041	0.0620	0.0421
100	Sep-06	0.1053	0.0600	0.0453
101	Oct-06	0.1030	0.0598	0.0432
102	Nov-06	0.1033	0.0580	0.0453
103	Dec-06	0.1035	0.0581	0.0454
104	Jan-07	0.1013	0.0596	0.0417
105	Feb-07	0.1018	0.0590	0.0428
106	Mar-07	0.1018	0.0585	0.0433
107	Apr-07	0.1007	0.0597	0.0410
108	May-07	0.0967	0.0599	0.0368
109	Jun-07	0.0970	0.0630	0.0340
110	Jul-07	0.1006	0.0625	0.0381
111	Aug-07	0.1021	0.0624	0.0397
112	Sep-07	0.1014	0.0618	0.0396
113	Oct-07	0.1080	0.0611	0.0469
114	Nov-07	0.1083	0.0597	0.0486
115	Dec-07	0.1084	0.0616	0.0468
116	Jan-08	0.1113	0.0602	0.0511
117	Feb-08	0.1139	0.0621	0.0518
118	Mar-08	0.1147	0.0621	0.0526
119	Apr-08	0.1167	0.0629	0.0538
120	May-08	0.1069	0.0627	0.0442
121	Jun-08	0.1062	0.0638	0.0424
122	Jul-08	0.1086	0.0640	0.0446
123	Aug-08	0.1123	0.0637	0.0486
124	Sep-08	0.1130	0.0649	0.0481
125	Oct-08	0.1213	0.0756	0.0457
126	Nov-08	0.1221	0.0760	0.0461
127	Dec-08	0.1162	0.0654	0.0508
128	Jan-09	0.1131	0.0639	0.0492
129	Feb-09	0.1155	0.0630	0.0524
130	Mar-09	0.1198	0.0642	0.0556
131	Apr-09	0.1146	0.0648	0.0498
132	May-09	0.1225	0.0649	0.0576
133	Jun-09	0.1208	0.0620	0.0588
134	Jul-09	0.1145	0.0597	0.0548
135	Aug-09	0.1109	0.0571	0.0538
136	Sep-09	0.1109	0.0553	0.0556
137	Oct-09	0.1146	0.0555	0.0592
138	Nov-09	0.1148	0.0564	0.0584
139	Dec-09	0.1123	0.0579	0.0544
140	Jan-10	0.1198	0.0577	0.0621
141	Feb-10	0.1167	0.0587	0.0580
142	Mar-10	0.1074	0.0584	0.0490
143	Apr-10	0.0934	0.0582	0.0352
144	May-10	0.0970	0.0552	0.0418
145	Jun-10	0.0953	0.0546	0.0407
146	Jul-10	0.1050	0.0526	0.0524
147	Aug-10	0.1038	0.0501	0.0537
148	Sep-10	0.1034	0.0501	0.0533
149	Oct-10	0.1050	0.0510	0.0540

LINE	DATE	DCF	BOND YIELD	RISK PREMIUM
150	Nov-10	0.1041	0.0536	0.0505
151	Dec-10	0.1029	0.0557	0.0472
152	Jan-11	0.1019	0.0557	0.0462
153	Feb-11	0.1004	0.0568	0.0436
154	Mar-11	0.1014	0.0556	0.0458
155	Apr-11	0.1031	0.0555	0.0476
156	May-11	0.1018	0.0532	0.0486
157	Jun-11	0.1020	0.0526	0.0494
158	Jul-11	0.1035	0.0527	0.0508
159	Aug-11	0.1179	0.0469	0.0710
160	Sep-11	0.1155	0.0448	0.0707
161	Oct-11	0.1150	0.0452	0.0698
162	Nov-11	0.1120	0.0425	0.0695
163	Dec-11	0.1092	0.0435	0.0657
164	Jan-12	0.1078	0.0434	0.0644
165	Feb-12	0.1081	0.0436	0.0645
166	Mar-12	0.1081	0.0448	0.0633
167	Apr-12	0.1133	0.0440	0.0693
168	May-12	0.1203	0.0420	0.0783
169	Jun-12	0.1013	0.0408	0.0605
170	Jul-12	0.0978	0.0393	0.0585
171	Aug-12	0.1025	0.0400	0.0625
172	Sep-12	0.1040	0.0402	0.0638
173	Oct-12	0.1011	0.0391	0.0620
174	Nov-12	0.1032	0.0384	0.0648
175	Dec-12	0.1023	0.0400	0.0623
176	Jan-13	0.1013	0.0415	0.0598
177	Feb-13	0.0982	0.0418	0.0564
178	Mar-13	0.1018	0.0420	0.0598
179	Apr-13	0.1001	0.0400	0.0601
180	May-13	0.1000	0.0417	0.0583
181	Jun-13	0.1000	0.0453	0.0547
182	Jul-13	0.0983	0.0468	0.0515
183	Aug-13	0.0982	0.0473	0.0509
184	Sep-13	0.0991	0.0480	0.0511
185	Oct-13	0.0998	0.0470	0.0528
186	Nov-13	0.0964	0.0477	0.0487
187	Dec-13	0.0966	0.0481	0.0485
188	Jan-14	0.0948	0.0463	0.0485
189	Feb-14	0.1019	0.0453	0.0566
190	Mar-14	0.1027	0.0451	0.0576
191	Apr-14	0.1081	0.0441	0.0640
192	May-14	0.1069	0.0426	0.0643
193	Jun-14	0.1059	0.0429	0.0630
194	Jul-14	0.1075	0.0423	0.0652
195	Aug-14	0.1069	0.0413	0.0656
196	Sep-14	0.1058	0.0424	0.0634
197	Oct-14	0.1131	0.0406	0.0725
198	Nov-14	0.1113	0.0409	0.0704
199	Dec-14	0.1105	0.0395	0.0710
200	Jan-15	0.1043	0.0358	0.0685
201	Feb-15	0.1043	0.0367	0.0676
202	Mar-15	0.1062	0.0374	0.0688
203	Apr-15	0.1072	0.0375	0.0697
204	May-15	0.1067	0.0417	0.0650

LINE	DATE	DCF	BOND YIELD	RISK PREMIUM
205	Jun-15	0.1020	0.0439	0.0581
206	Jul-15	0.0974	0.0440	0.0534
207	Aug-15	0.0949	0.0425	0.0524
208	Sep-15	0.0975	0.0439	0.0536
209	Oct-15	0.0961	0.0429	0.0532
210	Nov-15	0.1007	0.0440	0.0567
211	Dec-15	0.1027	0.0435	0.0592
212	Jan-16	0.1017	0.0427	0.0590
213	Feb-16	0.1002	0.0411	0.0591
214	Mar-16	0.0973	0.0416	0.0557
215	Apr-16	0.0974	0.0400	0.0574
216	May-16	0.0944	0.0393	0.0551
217	Jun-16	0.0963	0.0378	0.0585
218	Jul-16	0.0952	0.0357	0.0595
219	Aug-16	0.0971	0.0359	0.0612
220	Sep-16	0.0978	0.0366	0.0612
221	Oct-16	0.0990	0.0377	0.0613
222	Nov-16	0.1041	0.0408	0.0633
223	Dec-16	0.1032	0.0427	0.0605
224	Jan-17	0.1021	0.0414	0.0607
225	Feb-17	0.0991	0.0418	0.0573
226	Mar-17	0.0983	0.0423	0.0560
227	Apr-17	0.0975	0.0412	0.0563
228	May-17	0.0984	0.0412	0.0572
229	Jun-17	0.0968	0.0394	0.0574
230	Jul-17	0.0975	0.0399	0.0576
231	Aug-17	0.0955	0.0386	0.0569
232	Sep-17	0.0957	0.0387	0.0570
233	Oct-17	0.0975	0.0391	0.0584
234	Nov-17	0.0975	0.0383	0.0592
235	Dec-17	0.0915	0.0379	0.0536
236	Jan-18	0.0938	0.0386	0.0552
237	Feb-18	0.0994	0.0409	0.0585
238	Mar-18	0.0936	0.0413	0.0523
239	Apr-18	0.0920	0.0417	0.0503
240	May-18	0.0917	0.0428	0.0489
241	Jun-18	0.0920	0.0427	0.0493
242	Jul-18	0.0927	0.0427	0.0500
243	Aug-18	0.0936	0.0426	0.0510
244	Sep-18	0.0944	0.0432	0.0512
245	Oct-18	0.0944	0.0445	0.0499
246	Nov-18	0.0952	0.0452	0.0500
247	Dec-18	0.0971	0.0437	0.0534

The derivation of the updated ex ante risk premium cost of equity is shown in the following table:

1	Constant Coefficient		8.58%
2	Bond coefficient		(0.600)
3	Forecast bond yield =		5.5%
4	Bond coefficient x Bond yield		(0.033)
5	Ex Ante Risk Premium		5.25%
6	Forecast bond yield =		5.55%
7	Ex Ante Risk Premium Cost of Equity		10.8%

Notes: Utility bond yield information from *Mergent Bond Record* (formerly Moody's). See Appendix 4 for a description of my ex ante risk premium approach. DCF results are calculated using a quarterly DCF model as follows:

d_0	=	Latest quarterly dividend
P_0	=	Average of the monthly high and low stock prices for each month per Refinitiv (formerly known as Thomson Reuters
FC	=	Flotation cost allowance (five percent) as a percentage of stock price
g	=	I/B/E/S forecast of future earnings growth for each month
k	=	Cost of equity using the quarterly version of the DCF model

$$k = \left[\frac{d_0 (1+g)^{\frac{1}{4}}}{P_0 (1-FC)} + (1+g)^{\frac{1}{4}} \right]^4 - 1$$

ATMOS ENERGY
EXHIBIT__(JVW-1)
REBUTTAL SCHEDULE 3
COMPARATIVE RETURNS ON S&P 500 STOCK INDEX AND MOODY'S A-RATED UTILITY BONDS 1937 – 2018

LINE	YEAR	S&P 500 STOCK PRICE	STOCK DIVIDEND YIELD	STOCK RETURN	A-RATED BOND PRICE	BOND RETURN	RISK PREMIUM
1	2017	2,275.12	0.0209	24.71%	$96.13	10.75%	13.97%
2	2016	1,918.60	0.0222	20.80%	$95.48	4.87%	15.93%
3	2015	2,028.18	0.0208	-3.32%	$107.65	-7.59%	4.26%
4	2014	1,822.36	0.0210	13.39%	$89.89	24.20%	-10.81%
5	2013	1,481.11	0.0220	25.24%	$97.45	-3.65%	28.89%
6	2012	1,300.58	0.0214	16.02%	$94.36	7.52%	8.50%
7	2011	1,282.62	0.0185	3.25%	$77.36	27.14%	-23.89%
8	2010	1,123.58	0.0203	16.18%	$75.02	8.44%	7.74%
9	2009	865.58	0.0310	32.91%	$68.43	15.48%	17.43%
10	2008	1,378.76	0.0206	-35.16%	$72.25	0.24%	-35.40%
11	2007	1,424.16	0.0181	-1.38%	$72.91	4.59%	-5.97%
12	2006	1,278.72	0.0183	13.20%	$75.25	2.20%	11.01%
13	2005	1,181.41	0.0177	10.01%	$74.91	5.80%	4.21%
14	2004	1,132.52	0.0162	5.94%	$70.87	11.34%	-5.40%
15	2003	895.84	0.0180	28.22%	$62.26	20.27%	7.95%
16	2002	1,140.21	0.0138	-20.05%	$57.44	15.35%	-35.40%
17	2001	1,335.63	0.0116	-13.47%	$56.40	8.93%	-22.40%
18	2000	1,425.59	0.0118	-5.13%	$52.60	14.82%	-19.95%
19	1999	1,248.77	0.0130	15.46%	$63.03	-10.20%	25.66%
20	1998	963.35	0.0162	31.25%	$62.43	7.38%	23.87%
21	1997	766.22	0.0195	27.68%	$56.62	17.32%	10.36%
22	1996	614.42	0.0231	27.02%	$60.91	-0.48%	27.49%
23	1995	465.25	0.0287	34.93%	$50.22	29.26%	5.68%
24	1994	472.99	0.0269	1.05%	$60.01	-9.65%	10.71%
25	1993	435.23	0.0288	11.56%	$53.13	20.48%	-8.93%
26	1992	416.08	0.0290	7.50%	$49.56	15.27%	-7.77%
27	1991	325.49	0.0382	31.65%	$44.84	19.44%	12.21%
28	1990	339.97	0.0341	-0.85%	$45.60	7.11%	-7.96%
29	1989	285.41	0.0364	22.76%	$43.06	15.18%	7.58%
30	1988	250.48	0.0366	17.61%	$40.10	17.36%	0.25%
31	1987	264.51	0.0317	-2.13%	$48.92	-9.84%	7.71%
32	1986	208.19	0.0390	30.95%	$39.98	32.36%	-1.41%
33	1985	171.61	0.0451	25.83%	$32.57	35.05%	-9.22%
34	1984	166.39	0.0427	7.41%	$31.49	16.12%	-8.72%
35	1983	144.27	0.0479	20.12%	$29.41	20.65%	-0.53%
36	1982	117.28	0.0595	28.96%	$24.48	36.48%	-7.51%
37	1981	132.97	0.0480	-7.00%	$29.37	-3.01%	-3.99%
38	1980	110.87	0.0541	25.34%	$34.69	-3.81%	29.16%
39	1979	99.71	0.0533	16.52%	$43.91	-11.89%	28.41%
40	1978	90.25	0.0532	15.80%	$49.09	-2.40%	18.20%
41	1977	103.80	0.0399	-9.06%	$50.95	4.20%	-13.27%

LINE	YEAR	S&P 500 STOCK PRICE	STOCK DIVIDEND YIELD	STOCK RETURN	A-RATED BOND PRICE	BOND RETURN	RISK PREMIUM
42	1976	96.86	0.0380	10.96%	$43.91	25.13%	-14.17%
43	1975	72.56	0.0507	38.56%	$41.76	14.75%	23.81%
44	1974	96.11	0.0364	-20.86%	$52.54	-12.91%	-7.96%
45	1973	118.40	0.0269	-16.14%	$58.51	-3.37%	-12.77%
46	1972	103.30	0.0296	17.58%	$56.47	10.69%	6.89%
47	1971	93.49	0.0332	13.81%	$53.93	12.13%	1.69%
48	1970	90.31	0.0356	7.08%	$50.46	14.81%	-7.73%
49	1969	102.00	0.0306	-8.40%	$62.43	-12.76%	4.36%
50	1968	95.04	0.0313	10.45%	$66.97	-0.81%	11.26%
51	1967	84.45	0.0351	16.05%	$78.69	-9.81%	25.86%
52	1966	93.32	0.0302	-6.48%	$86.57	-4.48%	-2.00%
53	1965	86.12	0.0299	11.35%	$91.40	-0.91%	12.26%
54	1964	76.45	0.0305	15.70%	$92.01	3.68%	12.02%
55	1963	65.06	0.0331	20.82%	$93.56	2.61%	18.20%
56	1962	69.07	0.0297	-2.84%	$89.60	8.89%	-11.73%
57	1961	59.72	0.0328	18.94%	$89.74	4.29%	14.64%
58	1960	58.03	0.0327	6.18%	$84.36	11.13%	-4.95%
59	1959	55.62	0.0324	7.57%	$91.55	-3.49%	11.06%
60	1958	41.12	0.0448	39.74%	$101.22	-5.60%	45.35%
61	1957	45.43	0.0431	-5.18%	$100.70	4.49%	-9.67%
62	1956	44.15	0.0424	7.14%	$113.00	-7.35%	14.49%
63	1955	35.60	0.0438	28.40%	$116.77	0.20%	28.20%
64	1954	25.46	0.0569	45.52%	$112.79	7.07%	38.45%
65	1953	26.18	0.0545	2.70%	$114.24	2.24%	0.46%
66	1952	24.19	0.0582	14.05%	$113.41	4.26%	9.79%
67	1951	21.21	0.0634	20.39%	$123.44	-4.89%	25.28%
68	1950	16.88	0.0665	32.30%	$125.08	1.89%	30.41%
69	1949	15.36	0.0620	16.10%	$119.82	7.72%	8.37%
70	1948	14.83	0.0571	9.28%	$118.50	4.49%	4.79%
71	1947	15.21	0.0449	1.99%	$126.02	-2.79%	4.79%
72	1946	18.02	0.0356	-12.03%	$126.74	2.59%	-14.63%
73	1945	13.49	0.0460	38.18%	$119.82	9.11%	29.07%
74	1944	11.85	0.0495	18.79%	$119.82	3.34%	15.45%
75	1943	10.09	0.0554	22.98%	$118.50	4.49%	18.49%
76	1942	8.93	0.0788	20.87%	$117.63	4.14%	16.73%
77	1941	10.55	0.0638	-8.98%	$116.34	4.55%	-13.52%
78	1940	12.30	0.0458	-9.65%	$112.39	7.08%	-16.73%
79	1939	12.50	0.0349	1.89%	$105.75	10.05%	-8.16%
80	1938	11.31	0.0784	18.36%	$99.83	9.94%	8.42%
81	1937	17.59	0.0434	-31.36%	$103.18	0.63%	-31.99%
82	Average			11.4%		6.7%	4.7%

Note: See Appendix 5 for an explanation of how stock and bond returns are derived and the source of the data presented.

ATMOS ENERGY
EXHIBIT__(JVW-1)
REBUTTAL SCHEDULE 4
COMPARATIVE RETURNS ON S&P UTILITY STOCK INDEX
AND MOODY'S A-RATED UTILITY BONDS 1937 – 2018

LINE	YEAR	S&P UTILITY STOCK PRICE	STOCK DIVIDEND YIELD	STOCK RETURN	A-RATED BOND PRICE	BOND RETURN	RISK PREMIUM
1	2017			11.72%	$96.13	10.75%	0.97%
2	2016			17.44%	$95.48	4.87%	12.57%
3	2015			-3.90%	$107.65	-7.59%	3.69%
4	2014			28.91%	$89.89	24.20%	4.71%
5	2013			13.01%	$97.45	-3.65%	16.66%
6	2012			2.09%	$94.36	7.52%	-5.43%
7	2011			19.99%	$77.36	27.14%	-7.15%
8	2010			7.04%	$75.02	8.44%	-1.40%
9	2009			10.71%	$68.43	15.48%	-4.77%
10	2008			-25.90%	$72.25	0.24%	-26.14%
11	2007			16.56%	$72.91	4.59%	11.96%
12	2006			20.76%	$75.25	2.20%	18.56%
13	2005			16.05%	$74.91	5.80%	10.25%
14	2003			23.48%	$62.26	20.27%	3.21%
16	2002			-14.73%	$57.44	15.35%	-30.08%
17	2001	307.70	0.0287	-17.90%	$56.40	8.93%	-26.83%
18	2000	239.17	0.0413	32.78%	$52.60	14.82%	17.96%
19	1999	253.52	0.0394	-1.72%	$63.03	-10.20%	8.48%
20	1998	228.61	0.0457	15.47%	$62.43	7.38%	8.09%
21	1997	201.14	0.0492	18.58%	$56.62	17.32%	1.26%
22	1996	202.57	0.0454	3.83%	$60.91	-0.48%	4.31%
23	1995	153.87	0.0584	37.49%	$50.22	29.26%	8.23%
24	1994	168.70	0.0496	-3.83%	$60.01	-9.65%	5.82%
25	1993	159.79	0.0537	10.95%	$53.13	20.48%	-9.54%
26	1992	149.70	0.0572	12.46%	$49.56	15.27%	-2.81%
27	1991	138.38	0.0607	14.25%	$44.84	19.44%	-5.19%
28	1990	146.04	0.0558	0.33%	$45.60	7.11%	-6.78%
29	1989	114.37	0.0699	34.68%	$43.06	15.18%	19.51%
30	1988	106.13	0.0704	14.80%	$40.10	17.36%	-2.55%
31	1987	120.09	0.0588	-5.74%	$48.92	-9.84%	4.10%
32	1986	92.06	0.0742	37.87%	$39.98	32.36%	5.51%
33	1985	75.83	0.0860	30.00%	$32.57	35.05%	-5.04%
34	1984	68.50	0.0925	19.95%	$31.49	16.12%	3.83%
35	1983	61.89	0.0948	20.16%	$29.41	20.65%	-0.49%
36	1982	51.81	0.1074	30.20%	$24.48	36.48%	-6.28%
37	1981	52.01	0.0978	9.40%	$29.37	-3.01%	12.41%
38	1980	50.26	0.0953	13.01%	$34.69	-3.81%	16.83%
39	1979	50.33	0.0893	8.79%	$43.91	-11.89%	20.68%
40	1978	52.40	0.0791	3.96%	$49.09	-2.40%	6.36%
41	1977	54.01	0.0714	4.16%	$50.95	4.20%	-0.04%
42	1976	46.99	0.0776	22.70%	$43.91	25.13%	-2.43%

LINE	YEAR	S&P UTILITY STOCK PRICE	STOCK DIVIDEND YIELD	STOCK RETURN	A-RATED BOND PRICE	BOND RETURN	RISK PREMIUM
43	1975	38.19	0.0920	32.24%	$41.76	14.75%	17.49%
44	1974	48.60	0.0713	-14.29%	$52.54	-12.91%	-1.38%
45	1973	60.01	0.0556	-13.45%	$58.51	-3.37%	-10.08%
46	1972	60.19	0.0542	5.12%	$56.47	10.69%	-5.57%
47	1971	63.43	0.0504	-0.07%	$53.93	12.13%	-12.19%
48	1970	55.72	0.0561	19.45%	$50.46	14.81%	4.64%
49	1969	68.65	0.0445	-14.38%	$62.43	-12.76%	-1.62%
50	1968	68.02	0.0435	5.28%	$66.97	-0.81%	6.08%
51	1967	70.63	0.0392	0.22%	$78.69	-9.81%	10.03%
52	1966	74.50	0.0347	-1.72%	$86.57	-4.48%	2.76%
53	1965	75.87	0.0315	1.34%	$91.40	-0.91%	2.25%
54	1964	67.26	0.0331	16.11%	$92.01	3.68%	12.43%
55	1963	63.35	0.0330	9.47%	$93.56	2.61%	6.86%
56	1962	62.69	0.0320	4.25%	$89.60	8.89%	-4.64%
57	1961	52.73	0.0358	22.47%	$89.74	4.29%	18.18%
58	1960	44.50	0.0403	22.52%	$84.36	11.13%	11.39%
59	1959	43.96	0.0377	5.00%	$91.55	-3.49%	8.49%
60	1958	33.30	0.0487	36.88%	$101.22	-5.60%	42.48%
61	1957	32.32	0.0487	7.90%	$100.70	4.49%	3.41%
62	1956	31.55	0.0472	7.16%	$113.00	-7.35%	14.51%
63	1955	29.89	0.0461	10.16%	$116.77	0.20%	9.97%
64	1954	25.51	0.0520	22.37%	$112.79	7.07%	15.30%
65	1953	24.41	0.0511	9.62%	$114.24	2.24%	7.38%
66	1952	22.22	0.0550	15.36%	$113.41	4.26%	11.10%
67	1951	20.01	0.0606	17.10%	$123.44	-4.89%	21.99%
68	1950	20.20	0.0554	4.60%	$125.08	1.89%	2.71%
69	1949	16.54	0.0570	27.83%	$119.82	7.72%	20.10%
70	1948	16.53	0.0535	5.41%	$118.50	4.49%	0.92%
71	1947	19.21	0.0354	-10.41%	$126.02	-2.79%	-7.62%
72	1946	21.34	0.0298	-7.00%	$126.74	2.59%	-9.59%
73	1945	13.91	0.0448	57.89%	$119.82	9.11%	48.79%
74	1944	12.10	0.0569	20.65%	$119.82	3.34%	17.31%
75	1943	9.22	0.0621	37.45%	$118.50	4.49%	32.96%
76	1942	8.54	0.0940	17.36%	$117.63	4.14%	13.22%
77	1941	13.25	0.0717	-28.38%	$116.34	4.55%	-32.92%
78	1940	16.97	0.0540	-16.52%	$112.39	7.08%	-23.60%
79	1939	16.05	0.0553	11.26%	$105.75	10.05%	1.21%
80	1938	14.30	0.0730	19.54%	$99.83	9.94%	9.59%
81	1937	24.34	0.0432	-36.93%	$103.18	0.63%	-37.55%
82	Average			10.64%		6.67%	3.97%

Note: See Appendix 5 for an explanation of how stock and bond returns are derived and the source of the data presented. Because Standard & Poor's discontinued its historical S&P Utilities Index in December 2001, stock returns beginning in 2002 are based on the total returns for the EEI Index of United States shareholder-owned electric utilities, as reported by EEI on its website. http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/Pages/QtrlyFinancialUpdates.aspx

ATMOS ENERGY
EXHIBIT__(JVW-1)
REBUTTAL SCHEDULE 5
USING THE ARITHMETIC MEAN TO ESTIMATE
THE COST OF EQUITY CAPITAL

Consider an investment that in a given year generates a return of 30 percent with probability equal to 0.5 and a return of -10 percent with a probability equal to 0.5. For each one dollar invested, the possible outcomes of this investment at the end of year one are:

END OF YEAR 1	*WEALTH AFTER ONE YEAR*	*PROBABILITY*
	$1.30	0.5
	$0.90	0.5

At the end of year two, the possible outcomes are:

END OF YEAR 2	*WEALTH AFTER TWO YEARS*		*VALUE*	*PROBABILITY*	*WEALTH X PROBABILITY*
	(1.30) (1.30)	=	$ 1.69	0.25	$ 0.4225
	(1.30) (.9)	=	$ 1.17	0.25	$ 0.2925
	(.9) (1.30)	=	$ 1.17	0.25	$ 0.2925
	(.9) (.9)	=	$ 0.81	0.25	$ 0.2025
	Expected Wealth	=			$ 1.21

The expected value of this investment at the end of year two is $1.21. In a competitive capital market, the cost of equity is equal to the expected rate of return on an investment. In the above example, the cost of equity is that rate of return which will make the initial investment of one dollar grow to the expected value of $1.21 at the end of two years. Thus, the cost of equity is the solution to the equation:

$$1(1+k)^2 = 1.21 \text{ or}$$

$$k = (1.21/1)^{.5} - 1 = 10\%.$$

The arithmetic mean of this investment is:

$$(30\%)\ (.5) + (-10\%)\ (.5) = 10\%.$$

Thus, the arithmetic mean is equal to the cost of equity capital.

The geometric mean of this investment is:

$$[(1.3)\ (.9)]^{.5} - 1 = .082 = 8.2\%.$$

Thus, the geometric mean is not equal to the cost of equity capital.

The lesson is obvious: for an investment with an uncertain outcome, the arithmetic mean is the best measure of the cost of equity capital.

ATMOS ENERGY
EXHIBIT__(JVW-1)
REBUTTAL SCHEDULE-6
CALCULATION OF CAPITAL ASSET PRICING MODEL COST OF EQUITY
USING AN HISTORICAL 7.1 PERCENT RISK PREMIUM

LINE	COMPANY	VALUE LINE BETA	RISK-FREE RATE	MARKET RISK PREMIUM	BETA X RISK PREMIUM	CAPM COST OF EQUITY	MARKET CAP $ (MIL)	SIZE PREMIUM	SIZE-ADJUSTED CAPM
1	Atmos Energy	0.60	3.9%	7.1%	4.2%	8.3%	11,116	--	8.3%
2	Chesapeake Utilities	0.65	3.9%	7.1%	4.6%	8.7%	1,380	1.75%	10.4%
3	New Jersey Resources	0.70	3.9%	7.1%	4.9%	9.0%	4,286	1.02%	10.1%
4	NiSource Inc.	0.50	3.9%	7.1%	3.5%	7.6%	9,547	1.02%	8.6%
5	Northwest Nat. Gas	0.60	3.9%	7.1%	4.2%	8.3%	1,823	1.75%	10.1%
6	ONE Gas Inc.	0.65	3.9%	7.1%	4.6%	8.7%	4,354	1.02%	9.7%
7	South Jersey Inds.	0.80	3.9%	7.1%	5.7%	9.7%	2,516	1.02%	10.8%
8	Southwest Gas	0.70	3.9%	7.1%	4.9%	9.0%	4,197	1.02%	10.1%
9	Spire Inc.	0.65	3.9%	7.1%	4.6%	8.7%	3,846	1.02%	9.7%
10	UGI Corp.	0.80	3.9%	7.1%	5.7%	9.7%	9,694	1.02%	10.8%
11	Historical CAPM Result					8.8%			9.9%

Notes			
Estimates of Premiums for Company Size			
Decile	Smallest Mkt. Cap. ($Millions)	Largest Mkt. Cap. ($Millions)	Premium
Large-Cap (No Adjustment)	10,712.000		0
Mid-Cap (3-5)	2,392.689	10,711.194	1.02%
Low-Cap (6-8)	569.279	2,390.899	1.75%
Micro-Cap (9-10)	2.516	567.843	3.67%
Risk-free Rate	3.9%	Forecast Yield on Long-term Treasury Bonds	
Market Risk Premium	7.1%	Ibbotson	
Flotation - Natural Gas Utilities	0.15%		

Historical Ibbotson® SBBI® risk premium including years 1926 through year end 2017 from 2018 SBBI®. Value Line beta for comparable companies from Value Line Investment Analyzer. Treasury bond yield forecast from data in Value Line Selection & Opinion, November 30, 2018, and Energy Information Administration, determined as follows. Value Line forecasts a yield on 10-year Treasury notes equal to 3.5 percent. The spread between the average yield on 10-year Treasury notes (2.83 percent) and 20-year Treasury bonds (2.98 percent) is 15 basis points. Adding 15 basis points to Value Line's 3.5 percent forecasted yield on 10-year Treasury notes produces a forecasted yield of 3.65 percent for 20-year Treasury bonds (see Value Line Investment Survey, Selection & Opinion, November 30, 2018). EIA forecasts a yield of 4.07 percent on 10-year Treasury notes. Adding the 15 basis point spread between 10-year Treasury notes and 20-year Treasury bonds to the EIA forecast of 4.07 percent for 10-year Treasury notes produces an EIA forecast for 20-year Treasury bonds equal to 4.22 percent. The average of the forecasts is 3.94 percent (3.65 percent using Value Line data and 4.22 percent using EIA data).

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ATMOS ENERGY
EXHIBIT__(JVW-1)
REBUTTAL SCHEDULE-7
COMPARISON OF RISK PREMIUMS ON
S&P500 AND S&P UTILITIES 1937 – 2018

YEAR	S&P UTILITIES STOCK RETURN	SP500 STOCK RETURN	10-YR. TREASURY BOND YIELD	UTILITIES RISK PREMIUM	MARKET RISK PREMIUM
2017	0.1172	0.2471	0.0233	0.0939	0.2238
2016	0.1744	0.2080	0.0184	0.1560	0.1896
2015	-0.0390	-0.0332	0.0214	-0.0604	-0.0546
2014	0.2891	0.1339	0.0254	0.2637	0.1085
2013	0.1301	0.2524	0.0235	0.1066	0.2289
2012	0.0209	0.1602	0.0180	0.0029	0.1422
2011	0.1999	0.0325	0.0278	0.1721	0.0047
2010	0.0704	0.1618	0.0322	0.0382	0.1296
2009	0.1071	0.3291	0.0326	0.0745	0.2965
2008	-0.2590	-0.3516	0.0367	-0.2957	-0.3883
2007	0.1656	-0.0138	0.0463	0.1193	-0.0601
2006	0.2076	0.1320	0.0479	0.1597	0.0841
2005	0.1605	0.1001	0.0429	0.1176	0.0572
2004	0.2284	0.0594	0.0427	0.1857	0.0167
2003	0.2348	0.2822	0.0401	0.1947	0.2421
2002	-0.1473	-0.2005	0.0461	-0.1934	-0.2466
2001	-0.1790	-0.1347	0.0502	-0.2292	-0.1849
2000	0.3278	-0.0513	0.0603	0.2675	-0.1116
1999	-0.0172	0.1546	0.0564	-0.0736	0.0982
1998	0.1547	0.3125	0.0526	0.1021	0.2599
1997	0.1858	0.2768	0.0635	0.1223	0.2133
1996	0.0383	0.2702	0.0644	-0.0261	0.2058
1995	0.3749	0.3493	0.0658	0.3091	0.2835
1994	-0.0383	0.0105	0.0708	-0.1091	-0.0603
1993	0.1095	0.1156	0.0587	0.0508	0.0569
1992	0.1246	0.0750	0.0701	0.0545	0.0049
1991	0.1425	0.3165	0.0786	0.0639	0.2379
1990	0.0033	-0.0085	0.0855	-0.0822	-0.0940
1989	0.3468	0.2276	0.0850	0.2618	0.1426
1988	0.1480	0.1761	0.0884	0.0596	0.0877
1987	-0.0574	-0.0213	0.0838	-0.1412	-0.1051
1986	0.3787	0.3095	0.0768	0.3019	0.2327
1985	0.3000	0.2583	0.1062	0.1938	0.1521
1984	0.1995	0.0741	0.1244	0.0751	-0.0503
1983	0.2016	0.2012	0.1110	0.0906	0.0902
1982	0.3020	0.2896	0.1300	0.1720	0.1596
1981	0.0940	-0.0700	0.1391	-0.0451	-0.2091
1980	0.1301	0.2534	0.1146	0.0155	0.1388
1979	0.0879	0.1652	0.0944	-0.0065	0.0708

YEAR	S&P UTILITIES STOCK RETURN	SP500 STOCK RETURN	10-YR. TREASURY BOND YIELD	UTILITIES RISK PREMIUM	MARKET RISK PREMIUM
1978	0.0396	0.1580	0.0841	-0.0445	0.0739
1977	0.0416	-0.0906	0.0742	-0.0326	-0.1648
1976	0.2270	0.1096	0.0761	0.1509	0.0335
1975	0.3224	0.3856	0.0799	0.2425	0.3057
1974	-0.1429	-0.2086	0.0756	-0.2185	-0.2842
1973	-0.1345	-0.1614	0.0684	-0.2029	-0.2298
1972	0.0512	0.1758	0.0621	-0.0109	0.1137
1971	-0.0007	0.1381	0.0616	-0.0623	0.0765
1970	0.1945	0.0708	0.0735	0.1210	-0.0027
1969	-0.1438	-0.0840	0.0667	-0.2105	-0.1507
1968	0.0528	0.1045	0.0565	-0.0037	0.0480
1967	0.0022	0.1605	0.0507	-0.0485	0.1098
1966	-0.0172	-0.0648	0.0492	-0.0664	-0.1140
1965	0.0134	0.1135	0.0428	-0.0294	0.0707
1964	0.1611	0.1570	0.0419	0.1192	0.1151
1963	0.0947	0.2082	0.0400	0.0547	0.1682
1962	0.0425	-0.0284	0.0395	0.0030	-0.0679
1961	0.2247	0.1894	0.0388	0.1859	0.1506
1960	0.2252	0.0618	0.0412	0.1840	0.0206
1959	0.0500	0.0757	0.0433	0.0067	0.0324
1958	0.3688	0.3974	0.0332	0.3356	0.3642
1957	0.0790	-0.0518	0.0365	0.0425	-0.0883
1956	0.0716	0.0714	0.0318	0.0398	0.0396
1955	0.1016	0.2840	0.0282	0.0734	0.2558
1954	0.2237	0.4552	0.0240	0.1997	0.4312
1953	0.0962	0.0270	0.0281	0.0681	-0.0011
1952	0.1536	0.1405	0.0248	0.1288	0.1157
1951	0.1710	0.2039	0.0241	0.1469	0.1798
1950	0.0460	0.3230	0.0205	0.0255	0.3025
1949	0.2783	0.1610	0.0193	0.2590	0.1417
1948	0.0541	0.0928	0.0215	0.0326	0.0713
1947	-0.1041	0.0199	0.0185	-0.1226	0.0014
1946	-0.0700	-0.1203	0.0174	-0.0874	-0.1377
1945	0.5789	0.3818	0.0173	0.5616	0.3645
1944	0.2065	0.1879	0.0209	0.1856	0.1670
1943	0.3745	0.2298	0.0207	0.3538	0.2091
1942	0.1736	0.2087	0.0211	0.1525	0.1876
1941	-0.2838	-0.0898	0.0199	-0.3037	-0.1097
1940	-0.1652	-0.0965	0.0220	-0.1872	-0.1185
1939	0.1126	0.0189	0.0235	0.0891	-0.0046
1938	0.1954	0.1836	0.0255	0.1699	0.1581
1937	-0.3693	-0.3136	0.0269	-0.3962	-0.3405
Risk Premium 1937 to 2018				0.0552	0.0628
RP Utilities/RP SP500				0.88	

ATMOS ENERGY
EXHIBIT__(JVW-1)
REBUTTAL SCHEDULE-8
CALCULATION OF CAPITAL ASSET PRICING MODEL COST OF EQUITY
USING AN HISTORICAL 7.1 PERCENT RISK PREMIUM AND A 0.88 UTILITY BETA

		BETA	RISK-FREE RATE	MARKET RISK PREMIUM	BETA X MRP	MODEL RESULT
1	Historical Utility Beta	0.88	3.9%	7.1%	6.2%	10.3%

Historical utility beta per Rebuttal Schedule 7. Flotation cost of 15 basis points. Treasury bond yield forecast from data in Value Line Selection & Opinion, November 30, 2018, and Energy Information Administration, determined as follows. Value Line forecasts a yield on 10-year Treasury notes equal to 3.5 percent. The spread between the average yield on 10-year Treasury notes (2.83 percent) and 20-year Treasury bonds (2.98 percent) is 15 basis points. Adding 15 basis points to Value Line's 3.5 percent forecasted yield on 10-year Treasury notes produces a forecasted yield of 3.65 percent for 20-year Treasury bonds (see Value Line Investment Survey, Selection & Opinion, November 30, 2018). EIA forecasts a yield of 4.07 percent on 10-year Treasury notes. Adding the 15 basis point spread between 10-year Treasury notes and 20-year Treasury bonds to the EIA forecast of 4.07 percent for 10-year Treasury notes produces an EIA forecast for 20-year Treasury bonds equal to 4.22 percent. The average of the forecasts is 3.94 percent (3.65 percent using Value Line data and 4.22 percent using EIA data).

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ATMOS ENERGY
EXHIBIT__(JVW-1)
REBUTTAL SCHEDULE 9
CALCULATION OF CAPITAL ASSET PRICING MODEL COST OF EQUITY
USING DCF ESTIMATE OF THE EXPECTED RATE OF RETURN
ON THE MARKET PORTFOLIO

LINE	COMPANY	VALUE LINE BETA	RISK-FREE RATE	DCF S&P 500	MARKET RISK PREMIUM	BETA X RISK PREMIUM	CAPM COST OF EQUITY
1	Atmos Energy	0.60	3.9%	14.4%	10.5%	6.30%	10.4%
2	Chesapeake Utilities	0.65	3.9%	14.4%	10.5%	6.82%	10.9%
3	New Jersey Resources	0.70	3.9%	14.4%	10.5%	7.35%	11.4%
4	NiSource Inc.	0.50	3.9%	14.4%	10.5%	5.25%	9.3%
5	Northwest Nat. Gas	0.60	3.9%	14.4%	10.5%	6.30%	10.4%
6	ONE Gas Inc.	0.65	3.9%	14.4%	10.5%	6.82%	10.9%
7	South Jersey Inds.	0.80	3.9%	14.4%	10.5%	8.40%	12.5%
8	Southwest Gas	0.70	3.9%	14.4%	10.5%	7.35%	11.4%
9	Spire Inc.	0.65	3.9%	14.4%	10.5%	6.82%	10.9%
10	UGI Corp.	0.80	3.9%	14.4%	10.5%	8.40%	12.5%
11	DCF CAPM Result	0.66	3.9%	14.4%	10.5%	6.98%	11.1%
	Using Beta Equal to 0.88						
1	Historical Utility Beta	0.88	3.9%	14.4%	10.5%	9.24%	13.3%
	Average DCF CAPM Result						12.1%
	Risk-free Rate	3.94%					
	Flotation	0.15%					
	DCF S&P 500 December 2018	14.4%					

Beta per Value Line for proxy utilities and per Rebuttal Schedule 7. Treasury bond yield forecast from data in Value Line Selection & Opinion, November 30, 2018, and Energy Information Administration, determined as follows. Value Line forecasts a yield on 10-year Treasury notes equal to 3.5 percent. The spread between the average yield on 10-year Treasury notes (2.83 percent) and 20-year Treasury bonds (2.98 percent) is 15 basis points. Adding 15 basis points to Value Line's 3.5 percent forecasted yield on 10-year Treasury notes produces a forecasted yield of 3.65 percent for 20-year Treasury bonds (see Value Line Investment Survey, Selection & Opinion, November 30, 2018). EIA forecasts a yield of 4.07 percent on 10-year Treasury notes. Adding the 15 basis point spread between 10-year Treasury notes and 20-year Treasury bonds to the EIA forecast of 4.07 percent for 10-year Treasury notes produces an EIA forecast for 20-year Treasury bonds equal to 4.22 percent. The average of the forecasts is 3.94 percent (3.65 percent using Value Line data and 4.22 percent using EIA data).

ATMOS ENERGY
EXHIBIT__(JVW-1)
REBUTTAL SCHEDULE 9 (CONTINUED)
SUMMARY OF DISCOUNTED CASH FLOW ANALYSIS
FOR S&P 500 COMPANIES

	COMPANY	STOCK PRICE (P_0)	D_0	FORECAST OF FUTURE EARNINGS GROWTH	MODEL RESULT	MARKET CAP $ (MILS)
1	3M	198.00	5.44	9.11%	12.1%	109,109
2	ABBOTT LABORATORIES	70.39	1.28	11.69%	13.7%	120,098
3	ACTIVISION BLIZZARD	60.06	0.34	11.97%	12.6%	35,902
4	AGILENT TECHS.	67.63	0.66	10.51%	11.6%	20,765
5	ALBEMARLE	95.36	1.34	12.70%	14.3%	8,089
6	ALLEGION	86.75	0.84	11.28%	12.4%	7,643
7	ALLIANCE DATA SYSTEMS	197.80	2.28	12.08%	13.4%	8,404
8	ALTRIA GROUP	57.86	3.20	9.14%	15.3%	94,779
9	AMERISOURCEBERGEN	85.07	1.60	9.48%	11.6%	15,518
10	AON CLASS A	154.67	1.60	15.34%	16.5%	35,108
11	APPLE	193.95	2.92	13.00%	14.7%	744,220
12	APTIV	74.02	0.88	13.37%	14.7%	16,430
13	AT&T	30.46	2.04	5.88%	13.2%	208,515
14	AVERY DENNISON	94.05	2.08	13.41%	15.9%	7,517
15	BALL	46.22	0.40	10.81%	11.8%	14,972
16	BAXTER INTL.	66.70	0.76	13.70%	15.0%	33,355
17	BECTON DICKINSON	239.03	3.08	12.77%	14.2%	58,600
18	BLACKROCK	413.43	12.52	10.82%	14.2%	58,617
19	BRISTOL MYERS SQUIBB	52.91	1.64	10.95%	14.4%	81,708
20	CARNIVAL	57.30	2.00	11.92%	15.9%	26,232
21	CHUBB	128.63	2.92	10.79%	13.3%	57,246
22	CHURCH & DWIGHT CO.	62.71	0.87	10.26%	11.8%	15,921
23	CIGNA	208.58	0.04	15.69%	15.7%	68,464
24	CISCO SYSTEMS	45.72	1.32	9.15%	12.3%	191,033
25	CITRIX SYS.	105.72	1.40	10.87%	12.3%	13,907
26	COGNIZANT TECH.SLTN.'A'	68.92	0.80	12.66%	14.0%	36,351
27	CONSTELLATION BRANDS 'A'	195.98	2.74	11.71%	13.3%	27,725
28	COSTCO WHOLESALE	222.71	2.28	11.12%	12.3%	86,834
29	COTY CL.A	9.44	0.50	6.57%	12.3%	4,867
30	CUMMINS	141.44	4.56	12.21%	15.9%	20,891
31	CVS HEALTH	74.48	2.00	12.58%	15.6%	85,972
32	DARDEN RESTAURANTS	106.66	3.00	12.80%	16.0%	12,297
33	DOLLAR GENERAL	108.11	1.16	14.03%	15.3%	26,378
34	DOMINION ENERGY	72.59	3.34	7.37%	12.4%	49,117
35	EATON	74.77	2.64	10.54%	14.5%	29,085
36	ECOLAB	151.17	1.84	13.47%	14.9%	42,092
37	ELI LILLY	111.66	2.58	13.44%	16.1%	115,773
38	EMERSON ELECTRIC	67.89	1.96	11.43%	14.7%	35,503
39	FIDELITY NAT.INFO.SVS.	103.81	1.28	13.25%	14.7%	32,467
40	FORTIVE	74.04	0.28	14.21%	14.6%	21,761
41	GAP	26.59	0.97	10.82%	14.9%	9,555
42	HCA HEALTHCARE	134.11	1.40	15.25%	16.5%	41,248
43	HERSHEY	106.04	2.89	9.55%	12.6%	15,878
44	HOME DEPOT	179.66	4.12	14.09%	16.7%	185,423
45	HUMANA	319.58	2.00	16.07%	16.8%	38,150
46	ILLINOIS TOOL WORKS	131.60	4.00	11.70%	15.1%	41,542

	COMPANY	STOCK PRICE (P_0)	D_0	FORECAST OF FUTURE EARNINGS GROWTH	MODEL RESULT	MARKET CAP $ (MILS)
47	INTEL	46.99	1.20	10.23%	13.1%	207,844
48	INTERCONTINENTAL EX.	76.57	0.96	14.21%	15.6%	41,916
49	INTUIT	207.47	1.88	14.55%	15.6%	49,841
50	J M SMUCKER	104.14	3.40	8.40%	12.0%	10,855
51	JACOBS ENGR.	69.43	0.60	12.12%	13.1%	8,129
52	JP MORGAN CHASE & CO.	107.07	3.20	9.68%	13.0%	320,736
53	KLA TENCOR	93.17	3.00	9.94%	13.5%	13,149
54	KRAFT HEINZ	51.89	2.50	6.32%	11.5%	54,692
55	MARSH & MCLENNAN	83.24	1.66	12.83%	15.1%	39,944
56	MCCORMICK & COMPANY NV.	143.23	2.28	10.55%	12.3%	16,932
57	MERCK & COMPANY	73.55	2.20	9.39%	12.7%	191,102
58	MICROSOFT	105.88	1.84	13.68%	15.7%	779,213
59	MOTOROLA SOLUTIONS	123.93	2.28	15.34%	17.5%	18,887
60	NEWELL BRANDS (XSC)	19.70	0.92	6.42%	11.5%	9,350
61	NEXTERA ENERGY	173.73	4.44	9.30%	12.1%	83,597
62	NIKE 'B'	75.03	0.88	14.15%	15.5%	85,970
63	NVIDIA	187.20	0.64	15.56%	16.0%	82,411
64	PACKAGING CORP.OF AM.	94.14	3.16	10.61%	14.4%	7,978
65	PERKINELMER	84.96	0.28	15.19%	15.6%	8,499
66	PHILIP MORRIS INTL.	83.34	4.56	7.09%	13.1%	107,387
67	PNC FINL.SVS.GP.	128.22	3.80	11.13%	14.5%	52,409
68	PVH	116.75	0.15	12.97%	13.1%	6,842
69	QUALCOMM	61.16	2.48	10.73%	15.3%	68,330
70	RALPH LAUREN CL.A	118.74	2.50	11.41%	13.8%	5,422
71	ROCKWELL AUTOMATION	168.74	3.88	12.50%	15.1%	17,878
72	ROSS STORES	90.64	0.90	12.01%	13.1%	28,595
73	SEAGATE TECH.	41.99	2.52	6.06%	12.6%	10,469
74	SKYWORKS SOLUTIONS	78.17	1.52	10.90%	13.1%	11,653
75	SOUTHWEST AIRLINES	52.37	0.64	15.90%	17.3%	26,468
76	STANLEY BLACK & DECKER	125.34	2.64	10.77%	13.1%	17,463
77	STATE STREET	71.69	1.88	9.44%	12.3%	22,924
78	STRYKER	165.69	2.08	10.34%	11.7%	57,546
79	SYMANTEC	20.20	0.30	12.23%	13.9%	12,497
80	SYSCO	67.38	1.56	11.40%	14.0%	32,133
81	T ROWE PRICE GROUP	97.28	2.80	11.90%	15.2%	21,009
82	TAPESTRY	40.68	1.35	9.82%	13.5%	9,682
83	TECHNIPFMC	24.90	0.52	10.82%	13.2%	8,611
84	TEXAS INSTRUMENTS	96.81	3.08	13.13%	16.8%	86,535
85	THERMO FISHER SCIENTIFIC	234.95	0.68	12.15%	12.5%	88,430
86	TJX	50.23	0.78	11.39%	13.1%	52,322
87	TOTAL SYSTEM SERVICES	87.92	0.52	15.95%	16.6%	14,431
88	TRACTOR SUPPLY	89.87	1.24	14.50%	16.1%	10,122
89	UNITED PARCEL SER.'B'	108.52	3.64	11.59%	15.4%	65,308
90	UNITEDHEALTH GROUP	264.94	3.60	15.80%	17.4%	233,236
91	UNIVERSAL HEALTH SVS.'B'	126.22	0.40	11.21%	11.6%	9,836
92	WALGREENS BOOTS ALLIANCE	77.39	1.76	10.10%	12.6%	65,673
93	WELLS FARGO & CO	51.48	1.72	10.94%	14.7%	216,721
94	WHIRLPOOL	114.49	4.60	10.23%	14.7%	6,965
95	WILLIS TOWERS WATSON	148.09	2.40	13.39%	15.2%	19,405
96	Market-weighted Average				14.4%	

Notes: In applying the DCF model to the S&P 500, I included in the DCF analysis only those companies in the S&P 500 group which pay a dividend, have a positive growth rate, and have at least three analysts' long-term growth estimates. I also eliminated those 25 percent of companies with the highest and lowest DCF results, a decision which had no impact on my CAPM estimate of the cost of equity.

D_0	=	Current dividend per Refinitiv (formerly known as Thomson Reuters
P_0	=	Average of the monthly high and low stock prices during the three months ending December 2018 per Refinitiv (formerly Refinitiv (formerly known as Thomson Reuters)
g	=	I/B/E/S forecast of future earnings growth December 2018
k	=	Cost of equity using the quarterly version of the DCF model shown below:

$$k = \left[\frac{d_0 (1+g)^{\frac{1}{4}}}{P_0} + (1+g)^{\frac{1}{4}} \right]^4 - 1$$

BEFORE THE PUBLIC SERVICE COMMISSION
COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY	)	
	)	
CORPORATION FOR AN ADJUSTMENT	)	**Case No. 2018-00281**
	)	
OF RATES AND TARIFF MODIFICATIONS	)	

REBUTTAL TESTIMONY OF DANE A. WATSON, PE CDP

INDEX TO THE REBUTTAL TESTIMONY
OF DANE A. WATSON, WITNESS FOR
ATMOS ENERGY CORPORATION

TABLE OF CONTENTS

I. INTRODUCTION OF WITNESS

Q. PLEASE STATE YOUR NAME AND POSITION.

A. My name is Dane A. Watson. I am Managing Partner at Alliance Consulting Group. My address is 101 E. Park Blvd., Suite 220, Plano, Texas 75074

Q. DID YOU FILE DIRECT TESTIMONY IN THIS CASE?

A. Yes.

Q. HAVE YOU REVIEWED THE TESTIMONY ON DEPRECIATION EXPENSE RELATED TO THE USE OF THE AVERAGE LIFE GROUP ("ALG") PROCEDURE IN THIS CASE PUT FORWARD BY ATTORNEY GENERAL WITNESS MR. LANE KOLLEN?

A. Yes, I have.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond on behalf of Atmos Energy Corporation Kentucky Division ("Atmos Energy" or the "Company"), to the position taken by Attorney General Witness Mr. Lane Kollen regarding the use of the ALG procedure. Specifically, I explain why Mr. Kollen's proposal to adopt the Average Life Group ("ALG") procedure to establish depreciation rates should be rejected. Mr. Kollen's recommendations should be rejected in favor of the Kentucky Public Service Commission's ("KPSC" or the "Commission") long standing approval of the Equal Life Group ("ELG") procedure for Atmos Energy, both through stipulated agreement and litigated proceedings. The Company has been submitting and the Commission subsequently approving depreciation rates based on the ELG procedure as far back as 1999.[1]

III. BACKGROUND ON ATMOS ENERGY KENTUCKY DEPRECIATION STUDY

Q. WHEN DID ATMOS ENERGY KENTUCKY CONDUCT THE DEPRECIATION STUDY THAT IS THE BASIS FOR THE EXISTING DEPRECIATION RATES USED IN THIS CASE?

A. The last depreciation study conducted was as of September 30, 2014 and was submitted and approved by this Commission in Case No. 2015-00343. In that depreciation study, the Company requested and received depreciation rates using the ELG methodology.

Q. IS THERE NEW EVIDENCE PROVIDED BY MR. KOLLEN ON THE ELG PROCEDURE TO JUSTIFY HIS RECOMMENDATION TO MOVE AWAY FROM THE ESTABLISHED ELG PROCEDURE?

A. No. His only new "evidence" is that he cites that the Commission recently ordered ALG-based depreciation rates for Duke Kentucky in Case No. 2017-00321. He does not attempt to justify why an <u>electric</u> utility case involving a different company with different facts and circumstances would be directly applicable to Atmos Energy - nor why the ruling for one single electric company should create such dramatic reduction in depreciation expense for the gas company, Atmos Energy.[2] I

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[1] Case Nos. 99-070, 2006-00464, 2013-00148, and 2015-00343.

[2] When asked in discovery, in response to AG Response to Atmos Energy question no. 1, Mr. Kollen acknowledges that *he has not performed a study to determine the history of how utilities in Kentucky have come to utilize their current depreciation procedure, whether it be ALG or ELG.* However, Mr. Kollen believes that each Kentucky utility other than Atmos currently utilizes the ALG procedure to determine depreciation rates. *[emphasis added]*

would offer that the results of the Duke Kentucky Case, an electric utility, should not be considered precedent and automatically applied to Atmos Energy and there is no justification provided by Mr. Kollen as to why it should be. The Commission, as it has done previously, should consider the individual merits of each utility and the case.

Q. HAS MR. KOLLEN, IN OTHER CASES, VARIED FROM METHODOLOGIES SUPPORTED BY AUTHORITATIVE TEXTS AND STANDARD PRACTICE AS IT RELATES TO DEPRECIATION?

A. Yes. In Case No. 2017-00349, where new depreciation rates were not even part of the case, he attempted to offer several alternative net salvage methodologies to lower the depreciation expense of the Company.[3] None of which have any depreciation support by authoritative texts, published sources, or the industry. The Commission did not agree with Mr. Kollen and the existing approved rates were not changed. This is another example from Mr. Kollen disregarding established theoretically sound practice with the end result of decreasing depreciation expense. What is a fact is that both the ELG and ALG procedures are widely known, and in the case of Atmos Energy and the Kentucky Commission, the ELG has been routinely approved and has been recognized by depreciation experts (which I will discuss in detail later in my rebuttal testimony). Mr. Kollen's recommendation related to ELG should be dismissed.

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[3] Direct Testimony Lane Kollen, Case No. 2017-00349.

Q. DO YOU HAVE ANYTHING ELSE YOU WOULD LIKE TO DISCUSS BEFORE YOUR SPECIFIC REBUTTAL ON MR. KOLLEN'S TESTIMONY ON ALG RATES?

A. Yes. Mr. Kollen has been providing testimony in Kentucky for a number of years on a wide variety of topics. However, Mr. Kollen cannot calculate ALG depreciation rates[4], which he claims "is the most dominant procedure used by other electric and gas utilities".[5] This fact was further exemplified when the Attorney General's Office requested the Commission to compel Atmos Energy to perform the ALG calculations on the AG's behalf.[6] The lack of ability to even calculate one of the most basic components of depreciation should be factored into the veracity given to the opinion of and depreciation theory-related expertise of Mr. Kollen.

IV. RESPONSE TO ATTORNEY GENERAL ALG RATES

Q. PLEASE SUMMARIZE MR. KOLLEN'S PROPOSAL REGARDING THE DEPRECIATION PROCEDURE THAT SHOULD BE USED TO ESTABLISH DEPRECIATION RATES IN THIS CASE.

A. Mr. Kollen proposes to further reduce Atmos Energy's depreciation expense by over 30 percent simply by recommending a different depreciation procedure in this case than has been historically used by the Company and approved by the Commission.[7] The depreciation procedure refers to the grouping of assets with

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[4] AG Response to Commission Staff Data Request, Question 8 (a and b) Case No. 2017-00349.

[5] Direct Testimony Lane Kollen, Case No. 2018-00281, p. 7.

[6] Atmos Energy Compliance to PSC Order dated January 14, 2019; Calculation of ALG based depreciation rates for Case No. 2018-00281.

[7] Atmos Energy Response to Staff DR Set 2, Question 2-39 (a) Case Nos. 99-070, 2006-00464, 2013-00148, and 2015-00343.

respect to the depreciation rate calculation. There are two main depreciation procedures associated with large groups of assets comparable to those of the Company. These two procedures are known as the ALG procedure and the ELG procedure. Mr. Kollen argues that depreciation rates should be established for Atmos Energy using the ALG procedure instead of the ELG procedure. Notably, Mr. Kollen takes this position despite the fact that this Commission has repeatedly affirmed the use of the ELG procedure to establish depreciation rates for Atmos Energy for at least 20 years.

A. Depreciation Procedure - ELG versus ALG

Q. PLEASE DESCRIBE THE MAIN DIFFERENCE BETWEEN THE ELG AND ALG PROCEDURES?

A. The ELG procedure recognizes that individual assets within a group of assets have different lives, and therefore should be depreciated over different periods to fully recover the cost of each asset at the end of the life of that asset. The ALG procedure is in contrast to the ELG procedure, in that it indirectly (through the Iowa curve retirement dispersion) recognizes that individual assets within a group have different lives yet depreciates all assets over the "average" life. In the ALG procedure, the remaining depreciation on assets that retire before the average life of the group will effectively be recovered later through assets that retire after the average life.

Q. CAN YOU PROVIDE A SIMPLE EXAMPLE THAT ILLUSTRATES THESE DIFFERENCES?

A. Yes. Assume that we have a category containing two assets, both installed in the same year and each costing $10. Further assume that Asset A has a life of two years and Asset B has a life of eight years. The average service life of this group is five years ($10 x 2 years plus $10 x 8 years divided by $20). The following Table illustrates the difference between the ALG and the ELG procedures:

		ALG BASIS		**ELG BASIS**	
Period	**Balance**	**Accrual**	**EOY Reserve**	**Accrual**	**EOY Reserve**[8]
1	20.0	4.0	4.0	6.25	6.25
2	20.0	4.0	(2.0)	6.25	2.50
3	10.0	2.0	0.0	1.25	3.75
4	10.0	2.0	2.0	1.25	5.00
5	10.0	2.0	4.0	1.25	6.25
6	10.0	2.0	6.0	1.25	7.50
7	10.0	2.0	8.0	1.25	8.75
8	10.0	2.0	0.0	1.25	0.0

Q. WHAT DOES THIS TABLE ILLUSTRATE?

A. This Table illustrates a number of features of both the ALG and ELG procedures. First, there is retirement dispersion since each asset has a different life (i.e., the two assets retired at different ages). Second, neither of the assets has a life equivalent to the average service life. Third, both procedures provide for full recovery of the $20 investment. Fourth, and most importantly, the two-year asset is not recovered over its two-year life in the ALG procedure, but it is in the ELG procedure. As I

[8] EOY Reserve means end-of-year accumulated depreciation balance.

explain more fully below, there is a deferral of recovery inherent in the ALG procedure.

Q. PLEASE EXPLAIN.

A. Notice the end-of year ("EOY") Reserve Column for the ALG procedure at the end of Period 2: it is negative. This means that one must over-accrue depreciation for the long-lived asset (eight years) to make up for the under-accrual for the short-lived asset (two years) under the ALG procedure. In contrast, the ELG procedure provides the proper matching between asset consumption and depreciation and results in a more accurate depiction of each asset over its expected life.

Q. WHAT IS THE DIFFERENCE IN THE PATTERNS OF DEPRECIATION RATES FOR THE TWO PROCEDURES?

A. For the ALG procedure, the depreciation rate is always 20.00%, regardless of which assets are in service. For the ELG procedure, the depreciation rate is 31.25% for the first two years (6.25/20) to depreciate one asset over 8 years and one asset over two years and 12.50% for the remaining six years (1.25/10) to recover the remaining periods for the second asset.

Q. DOES THE ELG DEPRECIATION RATE CHANGE OVER TIME?

A. In theory, it can. In reality, the ELG depreciation rate remains relatively constant through time for accounts when normal growth is occurring.

Q. WHY IS THIS THE CASE?

A. This occurs because the Company's accounts are continuous property groups. That is, additions and retirements are continuously being made to the accounts and the actual ELG depreciation rate changes very little, if at all, over time in most cases.

However, in periods where there is significantly higher or lower than normal capital expenditures, such as infrastructure replacements or capital constraints, it is possible that there could be an increase or decrease in depreciation expense under the ELG approach. Increases and decreases in these scenarios are also possible under the ALG approach.

Q. DOES THE DEPRECIATION STUDY SHOW AN INCREASE?

A. No. Despite Atmos Energy's higher capital investment in infrastructure replacements for a safe and reliable system, the study (comparing ELG rates for existing and proposed deprecation rates) shows nearly no change. When comparing the depreciation expense using existing depreciation rates and the proposed depreciation rates, using plant balances at September 30, 2017, it results in a decrease of $38,294.[9]

Q. MR. KOLLEN CLAIMS THAT MOVING FROM ALG TO ELG HAS IMPLICATIONS,[10] BUT WHAT ARE THE IMPLICATIONS OF MOVING FROM ELG TO ALG AS MR. KOLLEN RECOMMENDS?

A. Using the depreciable balances at September 30, 2017 and applying the proposed ELG rates results in a small decrease ($38,294) in depreciation expense. Using the ALG rates applied to the same September 30, 2017 balances results in an additional $5.8 million decrease. Moving to the less accurate ALG procedure results in over a <u>31 percent decrease</u> in depreciation expense, deferring recovery of some investment until after the assets are retired and impacting both customers and the

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[9] Direct Testimony Dane A. Watson, Exhibit DAW-2, Appendix B.
[10] Direct Testimony Lane Kollen, p. 10.

Company. The negative impact to both customers and Atmos Energy is discussed in detail later in my testimony. Given that the ELG procedure has been in place since 1999, this dramatic and unsupported change should not be adopted.

Q. IS THE ELG PROCEDURE VIEWED AS A MORE ACCURATE DEPRECIATION PROCEDURE BY DEPRECIATION EXPERTS?

A. Yes. ELG has been historically recognized as the more theoretically correct depreciation procedure, first by Mr. Robley Winfrey (who was instrumental in designing the current depreciation system we use today) over 70 years ago. In fact, Mr. Winfrey stated that ELG is "the only mathematically correct [depreciation] procedure."[11] Some 30 years later, Mr. Winfrey reflected on the use of ELG and confirmed his earlier opinion that ELG was the most appropriate depreciation methodology.[12] Similarly, Dr. W. Chester Fitch and Dr. Frank K. Wolf, (who wrote the book on depreciation and trained me) are in agreement with Mr. Winfrey on the validity of the ELG method.[13] In short, it is (seemingly) arrogantly rejecting the strongly-held opinions of the most well-respected experts in the field of depreciation to argue, as Mr. Kollen does, that the ELG method is not more accurate.

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[11] Winfrey, Robley, Depreciation of Property Groups, Bulletin 155 at 71 (1969).
[12] W.C. Fitch, F. K. Wolf, and B.H. Bissinger, The Estimation of Depreciation, 53-54 (1982).
[13] Frank K. Wolf and W. C. Fitch, Depreciation Systems, 93 (1994).

Q. HAS THIS COMMISSION RECOGNIZED THAT THE ELG PROCEDURE IS A REASONABLE DEPRECIATION PROCEDURE?

A. Yes. In Case No. 2013-00148 the Commission stated Atmos Energy's rates were reasonable and should be approved for use.[14] Also, the fact the Commission has routinely approved ELG derived rates indicates support and/or its recognition that the ELG procedure provides a more accurate estimate of the actual consumption of the property. This is supported because the ELG procedure appropriately recognizes that specific assets within a FERC account retire at different ages, not over just the stated average service life of all assets in the account. As such, the ELG procedure groups assets that share similar lives within an account and appropriately calculates a theoretical reserve amount for that account to reflect retirements that occur at ages outside of the average, unlike the ALG procedure.

B. Commission precedent and Atmos Energy Kentucky's asset records support the use of the ELG procedure

Q. HAS THIS COMMISSION REPEATEDLY APPROVED ELG DERIVED DEPRECIATION RATES FOR ATMOS ENERGY'S KENTUCKY ASSETS?

A. Yes. As previously noted, the Commission has approved depreciation rates using the ELG procedure for Atmos Energy Kentucky's assets dating back to at least 1999.[15]

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[14] Final Order Case No. 2013-00148, p. 57.

[15] Case Nos. 99-070, 2006-00464, 2013-00148 and 2015-00343.

Q. DO ATMOS ENERGY'S ASSET RECORDS SUPPORT THE CONTINUED USE OF THE ELG PROCEDURE?

A. Yes. Atmos Energy maintains aged records for its assets and performs depreciation studies at regular intervals.[16] Atmos Energy's consistent historical use of ELG combined with detailed accounting records justifies its continued use of ELG.

C. Mr. Kollen's arguments against the ELG procedure are unpersuasive.

Q. ATTORNEY GENERAL WITNESS LANE KOLLEN CHARACTERIZES THE ELG PROCEDURE AS ACCELERATED DEPRECIATION. IS THIS AN ACCURATE CHARACTERIZATION?

A. No. An accurate characterization would be that the ALG procedure is actually a *deferred* approach compared to ELG and ALG is less precise. The example provided above illustrates the more accurate recovery of costs over the life of each asset under the ELG methodology.

Both procedures are straight-line methods of calculating depreciation so that asset groups are fully depreciated at the end of their service lives. The fact that ELG recognizes that some assets will be shorter-lived and should be depreciated over their shorter period (and also that long-lived assets should be depreciated over their longer life) is what makes it accurate in recovering the cost of individual assets over the life of each asset and the group. ALG, on the other hand, does not recognize the varying lives of assets within the same group. There is no "acceleration of depreciation" inherent in using a straight-line methodology that

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[16] See Atmos Energy Response to Staff DR Set 2, Question 2-41.

performs depreciation at an asset level - taking into account the life of that assets. The truth is that when you don't take into account the shorter lives of some assets within a group in the depreciation rate calculation, you defer the recovery of some of the cost recovery of that asset past when the asset retires. Additionally, Mr. Kollen incorrectly confuses the record in this case by stating "that if [the ELG procedure" is adopted after the utility historically has used the the ALG procedure, the capital recovery periods are accelerated and shortened..."[17] This statement is not applicable to Atmos Energy in this case since it has had ELG based depreciation rates for at least 20 years and is not asking for the "adoption" of ELG, simply the continued use of the procedure.

Q. CAN YOU PROVIDE AN EXAMPLE OF AN ACCOUNT DEPRECIATION RATE UNDER ELG THAT IS LOWER THAN THE DEPRECIATION RATE UNDER ALG?

A. Yes. In this study there are two: Account 353 Storage Lines has an ELG rate of 0.91% compared to the ALG rate of 1.12% and Account 355 Measuring and Regulating has an ELG rate of 1.67% compared to the ALG rate of 1.71%.[18] The ELG derived depreciation rates do not always produce a higher depreciation expense. It does, however, provide for a better matching to the recording of assets on the books of the Company.

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[17] Direct Testimony Lane Kollen, p. 10.
[18] Direct Testimony Lane Kollen, p. 8 Table.

Q. HOW DO YOU RESPOND TO MR. KOLLEN'S STATEMENT THAT ATMOS ENERGY WILL RECOVER ALL ITS INVESTMENT REGARDLESS OF THE PROCEDURE?

A. It is true that recovery under either approach occurs. The more critical question is which procedure will provide a more accurate and timely recovery of the capital investment through depreciation expense. The full recovery in either procedure is not an endorsement of ALG being a better approach. In reality, given the facts and details of the ELG procedure discussed above, as well as the opinions of the most respected experts in the field of depreciation, it is evident that Atmos Energy already has in place a superior approach that provides better matching and more accurate recovery of Atmos Energy Kentucky assets - Atmos Energy does not need a "new" approach.

Q. DOES THE ALG PROCEDURE PROVIDE A MORE NORMALIZED AND CONSTANT RATE APPLICATION ACROSS GENERATIONS OF RATEPAYERS?

A. No. In fact, it shifts costs to future generations. The ALG procedure considers all units in an account to be one group,[19] so all costs for the entire group are allocated over one life, the average service life. As stated in Depreciation Systems:[20]

> The ALG procedure treats each unit as though its life is equal to the average of the group. The ELG procedure treats each unit in the group as though its life was known. This is the basis for the argument that the equal life group procedure better matches depreciation charges with the life of the units in the group.

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[19] NARUC, Public Utility Depreciation Practices, 1996, p. 62.

[20] Depreciation Systems, by Drs. F. K. Wolf and W. C. Fitch, Iowa State University Press, 1994, p 93.

ALG relies on the last units in the group to achieve full recovery. ELG uses each ELG group appropriately to recover the capital for that group. By deferring capital recovery to the longest-surviving units in the group, ALG shifts the burden of capital recovery to future customers in return for lower immediate rates. Stated differently, future customers are paying depreciation expense on assets long after they have been retired under the ALG procedure. In contrast, the National Association of Regulatory Utility Commissioners ("NARUC") provides that the ELG procedure will group assets according to their service lives, with the units from each vintage expected to experience the same service life being included in the same life group.[21] NARUC further states "[t]his procedure permits accruing the full cost of the shorter lived units to the depreciation reserve while they are in service. Thus the longer-lived units bear only their own costs."[22]

Q. CAN YOU DESCRIBE HOW INTERGENERATIONAL INEQUITY OCCURS UNDER THE ALG PROCEDURE?

A. Yes. Assume that you have plant assets with an average 30-year life. Further assume that one of these assets is damaged and must be retired from service after two years. Under the ALG procedure, the cost of the retired asset will not be fully depreciated at the end of its two-year life. Instead, when the two-year asset is replaced at the end of its two-year life, the replacement asset will begin to be depreciated while at the same time, most of the cost of the retired asset will continue to be recovered from customers until it too is fully depreciated. Effectively, in year

[21] NARUC, Public Utility Depreciation Practices, 1996, p. 62.
[22] *Id*.

three, customers are paying for the new asset and also the retired two-year asset. This is the reality anytime you assign averaged depreciation lives for assets-it creates intergenerational inequities for future customers by deferring recovery of cost until later in the life of the group. Mr. Kollen's claims there is potential generational inequities due to the ELG is not supported.[23]

Q. DOES UNDERESTIMATING DEPRECIATION RATES HARM THE UTILITY AND THE CUSTOMER?

A. Yes. The goal of setting depreciation rates is to estimate them as accurately as possible - neither overestimating nor underestimating. In reality, there are impacts to both the Company and customers of over or under estimating depreciation expense. The realities caused by underestimated depreciation rates, such as reduced cash flow and problems it would generate as well as ignoring the fact that customers will, all else being equal, pay a higher long-term rate base return on investment if too little depreciation expense is recovered.

Q. IS THERE ANY OTHER COMMISSION THAT HAS ENDORSED THE ELG PROCEDURE AND ROUTINELY APPROVED ITS RATES?

A. Yes. The Railroad Commission of Texas ("RCT") ruled on the use of the ELG procedure in a highly litigated docket.[24] The RCT continued the approval of the ELG depreciation procedure for other Atmos Energy divisions.[25] The RCT has also

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[23] Attorney General's Responses to Commission Staff Data Request 1 (d) Case No. 2018-00281.

[24] In GUD No. 8664, the Commission found that "[the ELG procedure] provides a more accurate estimate of the actual consumption of the property."

[25] GUD No. 10000, Final Order (Apr. 18, 2007) Direct Testimony of Dane A. Watson, Exhibit DAW-1, p 1. & 8; GUD No. 9400, Final Order at FoF 102 (Mar. 25, 2004); GUD No. 8976, Final Order at FoF 134 (June 22, 2000); GUD No. 8664, 2nd Order on Rehearing Nunc Pro Tunc at FoF 92 (Nov. 25, 1997). *See* GUD No. 10174, Final Order at 40 (Oct. 2, 2012) GUD No. 10170, Final Order FOF 33 (Dec. 4, 2012) Direct Testimony

repeatedly approved the use of the ELG methodology to establish deprecation rates for CenterPoint and West Texas Gas, either as part of settlement agreements and in fully litigated proceedings.[26] In fact, the RCT has expressly precluded this issue from litigation in past rate cases involving Atmos Energy Corporation divisions because the RCT precedent on this issue was so well settled.[27]

Q. WAS THIS ISSUE EXTENSIVELY LITIGATED IN ANY OF THOSE CASES?

A. Yes. In fact, in Docket Nos. 8664 and 9145, the examiner recommended shifting to the ALG method, and the RCT expressly rejected the examiners' recommendations both times on the basis that ELG provided a better matching of capital consumption than ALG.[28] These orders, clearly demonstrate that the RCT has thoroughly considered this issue and concluded that the ELG procedure should be used to calculate depreciation rates[29] and has since that time continued to reaffirm its use in subsequent proceedings for all of its regulated gas utilities.

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of Dane A. Watson, Exhibit DAW-1, 8; GUD No. 9762, Final Order at 19; GUD No. 9670, Final Order at FoF 22 (Mar. 29, 2007); GUD No. 9400, Final Order at FOF 102 (Mar. 25, 2004); GUD Nos. 9145-9148, Final Order at FoF 111 (Nov. 20, 2000).

[26] GUD No. 10432, Final Order (Aug. 25, 2015) Direct Testimony of Dane A. Watson, Exhibit DAW-2, 15; GUD No. GUD No. 10235 Final Order at FoF 36 -40 (June 13, 2013); GUD No. 10182, Final Order (Dec. 7, 2012); *id*., Direct Testimony of Dane A. Watson, Exhibit DAW-1, p. 14; GUD No. 10038, Final Order (Apr. 18, 2011); *id*., Direct Testimony of Dane A. Watson, Exhibit DAW-1, 14 - 15; GUD No. 9902, PFD at 68 (May 4, 2010); *id*., Final Order Nunc Pro Tunc at FoF 27 (May 5, 2010); GUD 9002-9135, Final Order at (Dec. 1, 2000).GUD No. 10567.

[27] GUD No. 9670, Final Order at FoF 22 (Mar. 29, 2007); GUD No. 9762, Final Order at FoF 19 (June 25, 2008); GUD No. 10170, Final Order at FoF 33 (Dec. 4, 2012).

[28] GUD No. 8664, 2nd Order on Rehearing Nunc Pro Tunc at FoF 92 (Nov. 25, 1997) ("Because it provides a more accurate estimate of the actual consumption of property, the ELG depreciation procedure requested by Lone Star is reasonable."); GUD Nos. 9145-9148, Final Order at FoF 111 (Nov. 20, 2000).

[29] *Id*.

Q. IN YOUR OPINION SHOULD THE COMMISSION CONTINUE TO USE THE ELG PROCEDURE TO ESTABLISH DEPRECIATION RATES FOR ATMOS ENERGY?

A. Yes. The ALG procedure does not fully recognize that some assets retire before the average service life occurs (and it is clear that they can and do) and the longer-lived assets have to make up for those early retired assets. The reality is very few assets actually retire at the average service life. The ALG procedure can create intergenerational inequity and is not as accurate as ELG. The ELG procedure, on the other hand, does recognize and account for the retirement of assets at varying ages. The ELG procedure more accurately accounts for how assets are actually recorded in Atmos Energy's books and records. The use of the ELG procedure facilitates generational equity among all ratepayers. Finally, ELG has been in place and previously approved by this Commission.

V. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS YOU WOULD LIKE TO MAKE?

A. Yes. As shown in my rebuttal testimony, the position on ALG taken by Mr. Kollen is not supported by this Commission's precedent with Atmos Energy. Mr. Kollen's arguments are not supported by authoritative texts and he has inaccurately characterized the ELG procedure as accelerated when it is in fact recognized as a straight-line method and provides more accurate recovery of Atmos Energy's assets. My recommendations on depreciation are fair, reasonable, well supported by the analysis, and follow standard depreciation methods and procedures previously reviewed and approved by this Commission.

The depreciation rates used by the Company in this case provide for a fair and reasonable recovery of its assets from each generation of customers who use them.

I respectfully request that this Commission reject Mr. Kollen's recommendation and remain consistent by the continued approval of the ELG based depreciation rates contained in my study, and as submitted in this case by the Company.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.